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CHAPTER 5

REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 SUMMARY DESCRIPTION

The reactor coolant system (RCS) schematic shown on Figure 5.1-1 consists of three similar heat transfer loops connected in parallel to the reactor pressure vessel. Each loop contains a reactor coolant pump (RCP), steam generator, and associated piping and valves. In addition, the system includes a pressurizer, a pressurizer relief tank (PRT), interconnecting piping, and instrumentation necessary for operational control. All previously mentioned components are located in the containment building.

During operation, the RCS transfers the heat generated in the core to the steam generators where steam is produced to drive the turbine generator. Borated demineralized water is circulated in the RCS at a flow rate and temperature consistent with achieving the reactor core thermal-hydraulic performance. The water also acts as a neutron moderator and reflector and as a solvent for the neutron absorber used in chemical shim control.

The RCS pressure boundary provides a barrier against the release of radioactivity generated within the reactor and is designed to ensure a high degree of integrity throughout the life of the plant.

The RCS pressure is controlled by the pressurizer where water and steam are maintained in equilibrium by electrical heaters and water sprays. Steam can be formed (by the heaters) or condensed (by the pressurizer spray) to minimize pressure variations due to contraction and expansion of the reactor coolant. Spring-loaded safety valves and power-operated relief valves (PORVs) are mounted on the pressurizer and when actuated discharge to the PRT, where the steam is condensed and cooled by mixing with water.

The extent of the RCS is defined as:

1. The reactor vessel including control rod drive mechanism (CRDM) housings.
2. The reactor coolant side of the steam generators.
3. Reactor coolant pumps.
4. A pressurizer attached to one of the reactor coolant loops.
5. The pressurizer relief tank.
6. Safety and relief valves.

7. The interconnecting piping, valves, and fittings between the principal components previously listed.

8. The piping, fittings, and valves leading to connecting auxiliary or support systems.

The following describes the RCS components.

1. Reactor vessel - The reactor vessel is cylindrical, with a welded hemispherical bottom head and a removable, flanged and gasketed, hemispherical upper head. The vessel contains the core, core supporting structures, control rods, and other parts directly associated with the core. The vessel has inlet and outlet nozzles located in a horizontal plane just below the reactor vessel flange but above the top of the core. Coolant enters the vessel through the inlet nozzles and flows down the core barrel-vessel wall annulus, turns at the bottom and flows up through the core to the outlet nozzles.

2. Steam generators - The steam generators are vertical shell and U-tube evaporators with integral moisture-separating equipment. The reactor coolant flows through the inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the steam generator. Steam is generated on the shell side and flows upward through the moisture separators to the outlet nozzle at the top of the vessel.

3. Reactor coolant pumps - The RCPs are identical, single-speed, centrifugal units driven by air-cooled, three-phase induction motors. The shaft is vertical with the motor mounted above the pumps. A flywheel on the shaft above the motor provides additional inertia to extend pump coastdown. The inlet is at the bottom of the pump; discharge is on the side.

4. Piping - The reactor coolant loop piping is specified in sizes consistent with system requirements. The hot-leg inside diameter (ID) is 29 inches and the ID of the cold-leg return line to the reactor vessel is 27 1/2 inches. The piping between the steam generator and the pump suction is increased to 31 inches ID to reduce pressure drop and improve flow conditions to the pump suction.

5. Pressurizer - The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads. Electrical heaters are installed through the bottom head of the vessel while the spray nozzle, relief, and safety valve connections are located in the top head of the vessel.

6. Pressurizer relief tank - The PRT is a horizontal, cylindrical vessel with elliptical dished heads. Steam from the pressurizer safety and relief valves are discharged into the PRT through a sparger pipe under the water level. This condenses and cools the steam by mixing it with water that is near ambient temperature.

7. Safety and relief valves - The pressurizer safety valves are of the totally-enclosed, pop-type. The valves are spring-loaded, self-activated with back pressure compensation. The PORVs limit system pressure for large power mismatch. They are operated automatically or by remote manual control. Remotely-operated valves are provided to isolate the inlet to the PORVs if excessive leakage occurs.

   The PORVs, with additional actuation logic, are also utilized to mitigate potential RCS cold overpressurization transients. The system provides the capability for additional RCS letdown, thereby maintaining RCS temperature and pressure within limits based on Appendix G requirements.

   Additionally, the PORVs are available for venting steam from the pressurizer to the PRT to create an alternate means of depressurizing the RCS instead of utilizing the pressurizer spray.

8. Loop stop valves - Reactor coolant loop stop valves are remotely-controlled, motor-operated gate valves which permit any loop to be isolated from the reactor vessel. The valve on the hot leg is like the one on the cold leg, except for the internal diameter of the valve ends. A discussion of operation of the valves is given in Section 5.4.12 and the analysis for the startup of an inactive loop, applicable in Modes 5 and 6 only, is given in Section 15.4. Safety limits and limiting safety system settings are discussed as part of the Technical Specification limitations in Chapter 16.

9. Reactor vessel head vent system - The reactor vessel head vent system consists of 4 solenoid operated open/closed isolation valves in parallel which are provided to remove noncondensible gases and steam from the reactor vessel and furnish a safety related means of RCS letdown.

The following describes the RCS performance characteristics. Important design and performance characteristics of the RCS are provided in Table 5.1-1.

The reactor coolant flow, a major parameter in the design of the system and its components, is established with a detailed design procedure supported by operating plant performance data, by pump model tests and analysis, and by pressure drop tests and analyses of

the reactor vessel and fuel assemblies. Data from all operating plants have indicated that the actual flow has been well above the flow specified for the thermal design of the plant. By applying the design procedure described subsequently, it is possible to specify the expected operating flow with reasonable accuracy.

Three reactor coolant flow rates are identified for the various plant design considerations.

1. Best estimate flow - The best estimate flow is the most likely value for the actual plant operating condition. This flow is based on the best estimate of the reactor vessel, steam generator, and piping flow resistance, and on the best estimate of the RCP head-flow capacity, with no uncertainties assigned to either the system flow resistance or the pump head. System pressure drops, based on best estimate flow, are presented in Table 5.1-1. Although the best estimate flow is the most likely value to be expected in operation, more conservative flow rates are applied in the thermal and mechanical designs.

2. Thermal design flow - Thermal design flow is the basis for the reactor core thermal performance, the steam generator thermal performance, and the nominal plant parameters used throughout the design. To provide the required margin, the thermal design flow accounts for the uncertainties in reactor vessel, steam generator and piping flow resistances, RCP head, and the methods used to measure flow rate. The thermal design flow is approximately 10 percent less than the best estimate flow. The thermal design flow is confirmed when the plant is placed in operation. Tabulations of important design and performance characteristics of the RCS, as provided in Table 5.1-1, are based on the thermal design flow.

3. Mechanical design flow - Mechanical design flow is the conservatively high flow used in the mechanical design of the reactor vessel internals and fuel assemblies. To assure that a conservatively high flow is specified, the mechanical design flow is based on a reduced system resistance and on increased pump head capability. The mechanical design flow is approximately four percent greater than the best estimate flow. Maximum pump overspeed results in a peak reactor coolant flow of 120 percent of the mechanical design flow. This overspeed condition, which is coincident with a turbine-generator overspeed of 20 percent, applies when a turbine trip is actuated only if the turbine governor fails and the turbine is tripped by the mechanical overspeed trip device.

The interrelated performance and safety functions of the RCS and its major components are listed below:

1. The RCS provides sufficient heat transfer capability to transfer the heat produced during power operation and when the reactor is subcritical, including the initial phase of plant cooldown, to the steam and power conversion system.

2. The system provides sufficient heat transfer capability to transfer the heat produced during the subsequent phase of plant cooldown and cold shutdown to the residual heat removal system.

3. The system heat removal capability under power operation and normal operational transients, including the transition from forced to natural circulation, shall assure no fuel damage within the operating bounds permitted by the reactor control and protection systems.

4. The RCS provides the water used as the core neutron moderator and reflector and as a solvent for chemical shim control.

5. The system maintains the homogeneity of the soluble neutron poison concentration and the rate of change of coolant temperature such that uncontrolled reactivity changes do not occur.

6. The reactor vessel is an integral part of the RCS pressure boundary and is capable of accommodating the temperatures and pressures associated with the operational transients. The reactor vessel functions to support the reactor core and CRDM. The vessel head is equipped with a vent to the PRT which supplies an additional means of pressure relief from the RCS if required.

7. The pressurizer maintains the system pressure during operation and limits pressure transients. During the reduction or increase of plant load, reactor coolant volume changes are accommodated in the pressurizer via the surge line.

8. The RCPs supply the coolant flow necessary to remove heat from the reactor core and transfer it to the steam generators.

9. The steam generators provide high quality steam to the turbine. The tube and tubesheet boundary are designed to prevent or control to acceptable levels the transfer of activity generated within the core to the secondary system.

10. The RCS piping serves as a boundary for containing the coolant under operating temperature and pressure conditions and for limiting leakage (and activity release) to the containment atmosphere. The RCS piping contains demineralized borated water which is circulated at the flow rate and temperature consistent with achieving the reactor core thermal and hydraulic performance.

5.1.1 Schematic Flow Diagram

The RCS is shown schematically on Figure 5.1-1. Design and Operating pressures, temperatures, and flow rates of the system under normal steady-state, full-power, operating conditions are presented in Table 5.1-1. The RCS volume under these conditions is presented in Table 5.1-1.

Tables for Section 5.1

TABLE 5.1-1

REACTOR COOLANT SYSTEM
DESIGN AND OPERATING PARAMETERS*

Characteristics	Parameters
Plant design life (years)	40***
Nominal operating pressure (psig)	2,235
Total system volume including pressurizer and surge line (ft^3)	9,650
Pressurizer spray rate, design (gpm)	600
Pressurizer heater capacity (kW)	1,400
Pressurizer relief tank volume (ft^3)	1,300

System Thermal and Hydraulic Data
(3 Reactor Coolant Pumps Running)

NSSS power (MWt)		2,910
Reactor power (MWt)		2,900
Thermal design flows (gpm)		
Active loop		87,200
Reactor		261,600
Mechanical design flows (gpm)		
Active loop		101,400
Reactor		304,200
	High Tavg (580.0°F)	Low Tavg (566.2°F)
Total reactor flow (lb/hr x 10^6)	99.3	101.1
Temperature (°F)		
Reactor vessel outlet	617.0	603.9
Reactor vessel inlet	543.1	528.5
Steam generator outlet	542.8	528.2
Steam generator steam	518.1	493.3
Feedwater**	455	400
Steam generator tube plugging, %**	0	22
Steam pressure (psia)	799	641
Total steam flow (lb/hr x 10^6)	13.04	12.03
Best estimate flows (gpm)		
Active loop	97,500	90,800
Reactor	292,500	272,400

* Parameter ranges are given, where appropriate, for high temperature and low temperature operating conditions, and are based on Tavg values of 580.0°F and 566.2°F, respectively.

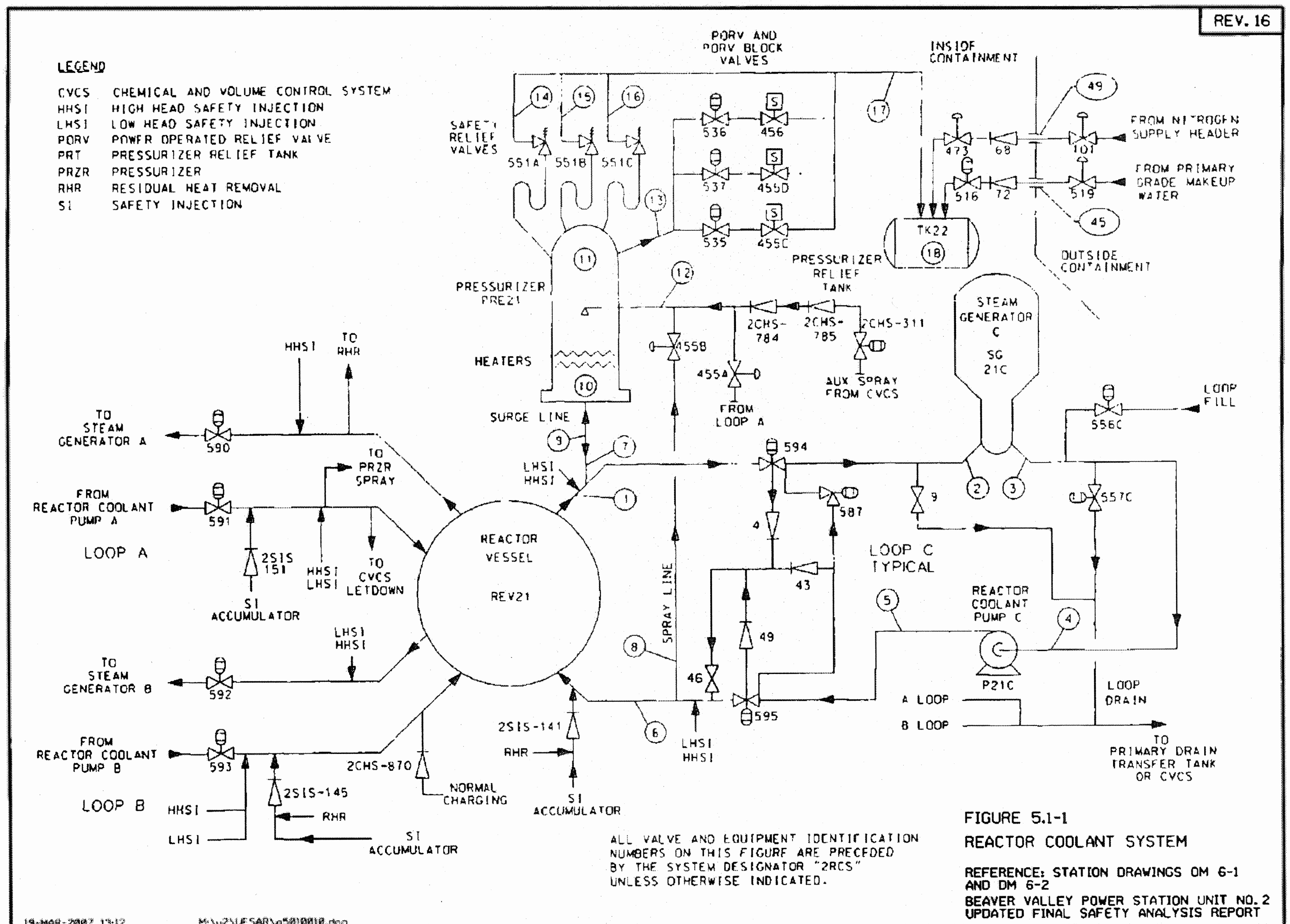
** Range includes operation over Tavg range specified above, as well as the effect of operation over a range of feedwater temperature (400°F and 455°F) and a range of steam generator tube plugging (0% and 22%).

*** License Renewal has extended the operating term of the plant to 60 years, but did not affect other parameters in this table.

TABLE 5.1-1 (Cont)

Characteristics	Parameters
System Pressure Drops (Estimated)[1]	
Reactor vessel Δp (psi)	40.2
Steam generator Δp (psi)	48.2
Hot leg piping Δp (psi)	2.7
Pump suction piping Δp (psi)	2.7
Cold leg piping Δp (psi)	2.8
Pump head (ft)	295

(1) Estimate based on best estimate flow of 90,800 gpm/loop and steam generator tube plugging of 22%.



ALL VALVE AND EQUIPMENT IDENTIFICATION NUMBERS ON THIS FIGURE ARE PRECEDED BY THE SYSTEM DESIGNATOR "2RCS" UNLESS OTHERWISE INDICATED.

FIGURE 5.1-1
REACTOR COOLANT SYSTEM

REFERENCE: STATION DRAWINGS OM 6-1 AND OM 6-2

BEAVER VALLEY POWER STATION UNIT NO. 2
UPDATED FINAL SAFETY ANALYSIS REPORT

5.2 INTEGRITY OF REACTOR COOLANT PRESSURE BOUNDARY

This section of the UFSAR discusses the measures employed to provide and maintain the integrity of the reactor coolant pressure boundary (RCPB) for the Beaver Valley Power Station - Unit 2 (BVPS-2) design lifetime. In this context, the RCPB is as defined in Section 50.2 (v) of 10 CFR 50 and extends to the outermost containment isolation valve in system piping which penetrates the containment and is connected to the reactor coolant system (RCS). Since other sections of this UFSAR describe the components of the auxiliary fluid systems, this section will be limited to the components of the RCS as defined in Section 5.1, unless otherwise noted.

For additional information on the RCS and for components which are part of the RCPB but are not described in this section, refer to the following sections:

Section 6.3 - For discussions of the RCPB components which are part of the emergency core cooling system.

Section 9.3.4 - For discussions of the RCPB components which are part of the chemical and volume control system (CVCS).

Section 3.9N.1 - For discussions of the design loadings, stress limits, and analyses applied to the RCS and ASME Code Class 1 components.

Section 3.9N.3 - For discussions of the design loadings, stress limits, and analyses applied to ASME Code Class 2 and 3 components.

5.2.1 Compliance With Codes and Code Cases

5.2.1.1 Compliance With 10 CFR 50, Section 50.55a

Reactor coolant system components will be designed and fabricated in accordance with the rules of 10 CFR 50, Section 50.55a, Codes and Standards. The addenda of the ASME Code applied in the design of each component is listed in Table 5.2-1.

5.2.1.2 Applicable Code Cases

Compliance with Regulatory Guides 1.84 and 1.85 is discussed in Section 1.8. The following discussion addresses only unapproved or conditionally approved Section III ASME Code Cases (Regulatory Guides 1.84 and 1.85) used on Class 1 primary components.

Code Case 1528 (SA 508 Class 2A) material has been used in the manufacture of the BVPS-2 steam generators and pressurizer. It should be noted that the purchase orders for this equipment were

placed prior to the original issue of Regulatory Guide 1.85 (June 1974). Regulatory Guide 1.85 (December 1980) reflects a conditional USNRC approval of Code Case 1528. Westinghouse Electric Corporation (Westinghouse) has conducted a test program which demonstrates the adequacy of Code Case 1528 material. The results of the test program are documented in WCAP-9292 (Westinghouse 1978). WCAP-9292 (Westinghouse 1978) and a request for approval of the use of Code Case 1528 have been submitted to the USNRC (Eicheldinger 1978).

5.2.2 Overpressure Protection

Reactor coolant system overpressure protection is accomplished by the utilization of pressurizer safety relief valves along with the reactor protection system (RPS) and associated equipment. Combinations of these systems provide compliance with the overpressure requirements of the ASME Boiler and Pressure Vessel Code, Section III, Subarticles NB-7400 and NC-7400, for pressurized water reactor (PWR) systems.

Auxiliary or emergency systems connected to the RCS are not utilized for prevention of RCS overpressurization protection.

5.2.2.1 Design Bases

Overpressure protection is provided for the RCS by the pressurizer safety valves which discharge to the pressurizer relief tank (PRT) by a common header. The transient which sets the design requirements for the primary system overpressure protection is a complete loss of steam flow to the turbine with credit taken for steam generator safety valve operation. For the sizing of the pressurizer safety valves, main feedwater flow is maintained and no credit is taken for reactor trip nor the operation of the following:

1. Pressurizer power-operated relief valves (PORVs), plus manual controls,
2. Steam line atmospheric dump valves (ADVs),
3. Steam dump system,
4. Reactor control system,
5. Pressurizer level control system, and
6. Pressurizer spray valve.

For this transient, the peak RCS and peak steam system pressures are limited to 110 percent of their respective design values.

The overpressure analysis is discussed in Section 15.2.

Overpressure protection for the steam system is described in Section 10.3.

Blowdown and heat dissipation systems of the nuclear steam supply system (NSSS) connected to the discharge of these pressure relieving devices are discussed in Section 5.4.11.

The steam generator blowdown system is discussed in Section 10.4.8.

Postulated events and transients on which the design requirements of the overpressure protection system are based are discussed in WCAP-7769, Rev. 1 (Cooper, et al, 1972).

5.2.2.2 Design Evaluation

A description of the pressurizer safety valves performance characteristics along with the design description of the incidents, assumptions made, method of analysis, and conclusions are discussed in Chapter 15.

The relief capacities of the pressurizer and steam generator safety valves are determined from the postulated overpressure transient conditions in conjunction with the action of the reactor protection system. An evaluation of the functional design of the overpressure protection system and an analysis of the capability of the system to perform its function for a typical plant are presented in WCAP-7769, Rev. 1 (Cooper, et al, 1972). The report describes in detail the types and number of pressure relief devices employed, relief device description, locations in the systems, reliability history, and the details of the methods used for relief device sizing based on typical worst-case transient conditions and analysis data for each transient condition. An overpressure protection report specifically for BVPS-2 is prepared in accordance with Article NB-7300 of Section III of the ASME Code.

The capacities of the pressurizer safety valves are discussed in Section 5.4.13.

5.2.2.3 Piping and Instrumentation Diagrams

Overpressure protection for the RCS is provided by pressurizer safety valves shown schematically on Figure 5.1-1. These valves discharge to the PRT by a common header.

The steam system safety valves are discussed in Section 10.3 and are shown on Figure 10.3-1.

5.2.2.4 Equipment and Component Description

The operation, significant design parameters, number and types of operating cycles, and environmental qualification of the pressurizer safety valves are discussed in Section 5.4.13. A discussion of the equipment and components of the steam system overpressure system is discussed in Section 10.3.

5.2.2.5 Mounting of Pressure Relief Devices

Westinghouse provides the installation guidelines and suggested physical layout as part of a systems standard design criteria document. The BVPS-2 system piping and support structures limit the piping reaction loads on the safety valves to acceptable values.

The pressurizer safety valves are mounted and supported from the pressurizer by means of metal bands around the pressurizer from which the individual support for each valve is attached. Design of the support and the bands is capable of accepting the reaction forces from valve lifting. Section 5.4.10 describes the support in greater detail.

Mounting of the components of the steam system overpressure system is discussed in Section 10.3.

5.2.2.6 Applicable Codes and Classification

The requirements of ASME Boiler and Pressure Vessel Code, Section III, Paragraphs NB-7300 (Overpressure Protection Report) and NC-7300 (Overpressure Protection Analysis), have been followed and complied with for pressurized water reactor systems.

Piping, valves, and associated equipment used for overpressure protection are classified in accordance with ANSI N18.2, Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants. These safety class designations are delineated in Table 3.2-1.

For further information, refer to Section 3.9.

5.2.2.7 Material Specifications

Refer to Section 5.2.3 for a description of material specifications.

5.2.2.8 Process Instrumentation

Each pressurizer safety valve discharge line incorporates a control board temperature indicator and alarm to notify the operator of steam discharge due to either leakage or actual valve operation. For a further discussion of process instrumentation associated with the system, refer to Chapter 7.0.

5.2.2.9 System Reliability

The reliability of the pressure relieving devices is discussed in Section 4 of WCAP-7769, Rev. 1 (Cooper, et al, 1972).

5.2.2.10 Testing and Inspection

Testing and inspection of the overpressure protection components are discussed in Section 5.4.13.4 and Chapter 14.

5.2.2.11 Reactor Coolant System Pressure Control During Low Temperature Operation

Administrative procedures are available to aid the operator in controlling RCS pressure during low temperature operation. However, to provide a backup to the operator and to minimize the frequency of RCS overpressurization, a system is provided to mitigate any inadvertent pressure excursion.

Protection against such overpressurization events is provided through the use of two PORVs to mitigate any potential pressure transients. Analyses have shown that one PORV is sufficient to prevent violation of these limits due to anticipated mass and heat input transients. The mitigation system is required only during low temperature water solid operation. It is manually armed and automatically actuated.

5.2.2.11.1 System Operation

Two pressurizer PORVs are each supplied with actuation logic to ensure that an automatic and independent RCS pressure control backup feature is available to the operator during low temperature operations. This system provides the capability for additional RCS inventory letdown, thereby maintaining RCS pressure within allowable limits. Refer to Sections 5.4.7, 5.4.10, 5.4.13, 7.7, and 9.3.4 for additional information on RCS pressure and inventory control during other modes of operation.

The basic function of the system logic is to continuously monitor RCS temperature and pressure conditions whenever BVPS-2 operation is at low temperatures. The system logic will first annunciate at a predetermined low RCS temperature to alert the operator to arm the system. An auctioneered system temperature will then be continuously converted to an allowable pressure and then compared to the actual RCS pressure. Another alarm on the main control board will annunciate whenever the measured pressure approaches, by a predetermined amount, the reference pressure. On further increase of the measured pressure, an actuation signal is transmitted to the PORVs to mitigate the pressure transient.

5.2.2.11.2 Evaluation of Low Temperature Overpressure Transients

Pressure Transient Analyses

ASME Section III, Appendix G, establishes guidelines and limits for RCS pressure primarily for low temperature conditions (≤350°F). The relief system operation discussed in Section 5.2.2.5 satisfies these conditions as discussed in the following paragraphs.

Transient analyses were performed to determine the maximum pressure for the postulated worst case mass input and heat input events.

The mass input transient analysis was performed assuming the inadvertent actuation of a high head safety injection pump, which in combination with other misoperation, pressurizes the RCS.

The heat input analysis was performed for an incorrect reactor coolant pump start assuming that the RCS was water solid at the initiation of the event and that a 50°F mismatch existed between the RCS (250°F) and the secondary side of the steam generators (300°F). (At lower temperatures, the mass input case is the limiting transient condition.)

5.2.2.11.3 Operating Basis Earthquake Evaluation

A fluid systems evaluation has been performed considering the potential for overpressure transients following an operating basis earthquake. The BVPS PORVs have been designed in accordance with the ASME code to provide the integrity required for the RCPB and qualified in accordance with the Westinghouse valve operability program which is described in detail in Section 3.9.3.2.

5.2.2.11.4 Administrative Procedures

Although the system described in Section 5.2.2.11.1 is designed to maintain RCS pressure within allowable limits, administrative procedures have been provided for minimizing the potential for any transient that could actuate the overpressure relief system.

5.2.3 Materials Selection, Fabrication, and Processing

5.2.3.1 Material Specifications

Material specifications used for the principal pressure retaining applications in each component of the RCPB are listed in Table 5.2-2 for ASME III Class 1 Primary Components and Table 5.2-3 for ASME III Class 1 and 2 Auxiliary Components. Tables 5.2-2 and 5.2-3 also include the unstabilized austenitic stainless steel material specifications used for the components in systems required for reactor shutdown or for emergency core cooling.

The unstabilized austenitic stainless steel material for the reactor vessel internals which are required for emergency core cooling for any mode of normal operation or under postulated accident conditions and for core structural load bearing members are listed in Table 5.2-4. In some cases, the tables may not be totally inclusive of the material specifications used in the listed applications. However, the listed specifications are representative of those materials utilized.

The materials utilized conform with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, plus applicable Addenda and Code Cases.

The welding materials used for joining the ferritic base materials of the RCPB conform to, or are equivalent to, ASME Material Specifications SFA 5.1, 5.2, 5.5, 5.17, 5.18, 5.20. They are qualified to the requirements of ASME Section III.

The welding materials used for joining the austenitic stainless steel base materials of the RCPB conform to ASME Material Specifications SFA 5.4 and 5.9. They are qualified to the requirement of ASME Section III.

The welding materials used for joining nickel-chromium-iron alloy in similar base material combination and in dissimilar ferritic or austenitic base material combination conform to ASME Material Specifications SFA 5.11 and 5.14. They are qualified to the requirements of ASME Section III.

5.2.3.2 Compatibility With Reactor Coolant

5.2.3.2.1 Chemistry of Reactor Coolant

The RCS chemistry specifications are given in Table 5.2-5. The RCS chemistry is selected to minimize corrosion. A routinely scheduled analysis of the coolant composition is performed to verify that the reactor coolant chemistry meets the specifications.

The CVCS provides a means for adding chemicals to the RCS which control the pH of the coolant during prestart-up testing and subsequent operation, scavenge oxygen from the coolant during heatup, and control radiolysis reactions involving hydrogen, oxygen, and nitrogen during all power operations subsequent to startup. Hydrogen peroxide may be added to the RCS via the CVCS during plant shutdown as part of RCS activity reduction efforts. The limits specified for chemical additives and reactor coolant impurities for power operation are shown in Table 5.2-5.

The pH control chemical specified, lithium hydroxide monohydrate, is enriched in Li-7 isotope to 99.9 percent. This chemical is chosen for its compatibility with the materials and water chemistry of borated water/stainless steel/zirconium/inconel systems. In addition, Li-7 is produced in solution from the neutron irradiation of the dissolved boron in the coolant. The lithium-7 hydroxide is

introduced into the RCS via the charging flow. The solution is prepared in the laboratory and transferred to the chemical addition tank. Primary grade water is then used to flush the solution to the suction header of the charging pumps. The concentration of lithium-7 hydroxide in the RCS is maintained in the range specified for pH control, (Table 5.2-5 discusses Li^7OH concentration specification). If the concentration exceeds this range, the cation bed demineralizer is employed in the letdown line in series operation with the mixed bed demineralizer to reduce the concentration to the allowable limits.

During reactor start-up from the cold condition, hydrazine is added to the coolant as an oxygen-scavenging agent. The hydrazine solution is introduced into the RCS in the same manner as described previously for the pH control agent.

The reactor coolant is treated with dissolved hydrogen to control the net decomposition of water by radiolysis in the core region. The hydrogen also reacts with oxygen and nitrogen introduced into the RCS as impurities under the impetus of core radiation. Sufficient partial pressure of hydrogen is maintained in the volume control tank (VCT) such that the specified equilibrium concentration of hydrogen is maintained in the reactor coolant. A self-contained pressure control valve maintains a minimum pressure in the vapor space of the VCT. This can be adjusted to provide the correct equilibrium hydrogen concentration.

Boron, in the chemical form of boric acid, is added to the RCS to accomplish long term reactivity control of the core. The mechanism for the process involves the absorption of neutrons by the B-10 isotope of naturally occurring boron.

A soluble zinc compound (zinc acetate dihydrate) is injected, by means of a zinc injection skid, into the RCS inventory during normal plant operation. The beneficial effects of zinc addition include reduction in shutdown radiation fields, reduction in the general corrosion rate of RCS component materials, reduction in both the initiation and propagation of Primary Water Stress Corrosion Cracking (PWSCC) of Alloy 600, and reduction in the long-term potential for Crud Induced Power Shift (CIPS).

The zinc compound is injected into the CVCS upstream of the charging pumps and downstream of the chemical mixing tank.

Suspended solids (corrosion product particulate) and other impurity concentrations are maintained below specified limits by controlling chemical quality of makeup water and chemical additives and by purification of the reactor coolant through the CVCS.

5.2.3.2.2 Compatibility of Construction Materials With Reactor Coolant

All of the ferritic low alloy and carbon steels which are used in principal pressure retaining applications are provided with corrosion resistant cladding on all surfaces that are exposed to the reactor coolant. The corrosion resistance of this cladding material is at least equivalent to the corrosion resistance of Types 304 and 316 austenitic stainless steel alloys or nickel-chromium-iron alloy, martensitic stainless steel, and precipitation hardened stainless steel. The cladding on ferritic type base materials receives a post-weld heat treatment, as required by the ASME Code Section III, Paragraph NB-4000.

Ferritic low alloy and carbon steel nozzles are safe-ended with either stainless steel wrought materials, stainless steel weld metal analysis A-7 (designated A-8 in the 1974 Edition of the ASME Code), or nickel-chromium-iron alloy weld metal F-Number 43. The latter buttering material requires further safe-ending with austenitic stainless steel base material after completion of the post-weld heat treatment when the nozzle is larger than a 4 inch nominal inside diameter and/or the wall thickness is greater than 0.531 inch.

All of the austenitic stainless steel and nickel-chromium-iron alloy base materials with primary pressure retaining applications are used in the solution annealed heat treated condition. These heat treatments are as required by the material specifications.

During subsequent fabrication, these materials are not heated above 800°F other than locally by welding operations. The solution annealed surge line material is subsequently formed by hot bending followed by a re-solution annealing heat treatment.

Components with stainless steel sensitized in the manner expected during component fabrication and installation will operate satisfactorily under normal BVPS-2 chemistry conditions in PWR systems because chlorides, fluorides, and oxygen are controlled to very low levels.

5.2.3.2.3 Compatibility With External Insulation and Environmental Atmosphere

All of the materials listed in Table 5.2-2 and 5.2-3 which are used in principal pressure retaining applications and which are subject to elevated temperature during system operation are in contact with thermal insulation that covers their outer surfaces.

The thermal insulation used on the RCPB is either the reflective stainless steel type or made of compounded materials which yield low leachable chloride and/or fluoride concentrations. The compounded materials in the form of blocks, boards, cloths, tapes, adhesives, and cements, are silicated to provide protection of austenitic stainless steels against stress corrosion which may result from accidental wetting of the insulation by spillage, minor leakage, or other contamination from the environmental atmosphere. Section 1.8.36 includes a discussion which indicates the degree of conformance with Regulatory Guide 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel.

In the event of coolant leakage, the ferritic materials will show increased general corrosion rates. Where minor leakage is anticipated from service experience, such as valve packing, pump seals, etc., only materials which are compatible with the coolant are used. These are as shown in Tables 5.2-2 and 5.2-3. Ferritic materials exposed to coolant leakage can be readily observed as part

of the inservice visual and/or nondestructive inspection program to assure the integrity of the component for subsequent service.

5.2.3.3 Fabrication and Processing of Ferritic Materials

5.2.3.3.1 Fracture Toughness

Assurance of adequate fracture toughness of ferritic materials in the RCPB (ASME Section III Class 1 Components) is provided by compliance with the requirements for fracture toughness testing included in Paragraph NB-2300 of Section III of the ASME Boiler and Pressure Vessel Code.

The fracture toughness properties of the reactor vessel materials are discussed in Section 5.3.

Limiting steam generator and pressurizer RT temperatures are guaranteed at 60°F for the base materials and the weldments. These materials will meet the 50 ft/lb absorbed energy and 35 mils lateral expansion requirements of the ASME Code Section III at 120°F. The actual results of these tests are provided in the ASME materials data reports which are supplied for each component and submitted to the owner at the time of shipment of the component and are maintained as QA records.

Calibration of temperature instruments and charpy impact test machines are performed to meet the requirements of the ASME Code Section III, Paragraph NB-2360.

Westinghouse has conducted a test program to determine the fracture toughness of low alloy ferritic materials with specified minimum yield strengths greater than 50,000 psi to demonstrate compliance with Appendix G of ASME Code Section III. In this program, fracture toughness properties were determined and shown to be adequate for base metal plates and forgings, weld metal, and heat-affected zone metal for higher strength ferritic materials used for components of the RCPB. The results of the program are documented in WCAP-9292 (Westinghouse 1978) which has been submitted to the USNRC for review.

5.2.3.3.2 Control of Welding

All welding is conducted utilizing procedures qualified according to the rules of Sections III and IX of the ASME Code. Control of welding variables, as well as examination and testing, during procedure qualification and production welding is performed in accordance with ASME Code requirements. Westinghouse practices for storage and handling of welding electrodes and fluxes comply with ASME Section III Paragraph NB-2400.

Section 1.8 provides discussions which indicate the degree of conformance of the ferritic materials components of the RCPB with Regulatory Guides 1.34, Control of Electroslag Properties, 1.43,

Control of Stainless Steel Weld Cladding of Low-Alloy Steel, 1.50, Control of Preheat Temperature for Welding of Low-Alloy Steel, and 1.71, Welder Qualification for Areas of Limited Accessibility.

5.2.3.4 Fabrication and Processing of Austenitic Stainless Steel

Sections 5.2.3.4.1 to 5.2.3.4.5 address Regulatory Guide 1.44, Control of the Use of Sensitized Stainless Steel, and present the methods and controls utilized by Westinghouse to avoid sensitization and prevent intergranular attack of austenitic stainless steel components. Section 1.8.44 includes a discussion which indicates the degree of conformance with Regulatory Guide 1.44.

5.2.3.4.1 Cleaning and Contamination Protection Procedures

All austenitic stainless steel materials used in the fabrication, installation, and testing of nuclear steam supply components and systems are required to be handled, protected, stored, and cleaned according to recognized and accepted methods which are designed to minimize contamination which could lead to stress corrosion cracking. The rules covering these controls are stipulated in the NSSS vendor process specifications. As applicable, these process specifications supplement the equipment specifications and purchase order requirements for NSSS austenitic stainless steel components or systems, regardless of the ASME Code Classification.

The process specifications which define these requirements and which follow the guidance of The American National Standards Institute N-45 committee specifications are as follows:

Number	Title
82560HM	Requirements for Pressure Sensitive Tapes for Use on Austenitic Stainless Steels.
83336KA	Requirements for Thermal Insulation Used on Austenitic Stainless Steel Piping and Equipment.
83860LA	Requirements for Marking of Reactor Plant Components and Piping.
84350HA	Site Receiving Inspection and Storage Requirements for Systems, Material, and Equipment.
8435lNL	Determination of Surface Chloride and Fluoride on Austenitic Stainless Steel Materials.
8531OQA	Packaging and Preparing Nuclear Components for Shipment and Storage.
292722	Cleaning and Packaging Requirements of Equipment for Use in the NSSS.

597756 Pressurized Water Reactor Auxiliary Tanks Cleaning Procedures.

597760 Cleanliness Requirements During Storage Construction, Erection, and Start-up Activities of Nuclear Power Systems.

Section 1.8 of Regulatory Guide 1.37 provides a discussion which indicates the degree of conformance of the austenitic stainless steel components of the RCPB with Regulatory Guide 1.37, Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants.

5.2.3.4.2 Solution Heat Treatment Requirements

The austenitic stainless steels listed in Tables 5.2-2, 5.2-3, and 5.2-4 are utilized in the final heat treated condition required by the respective ASME Code Section III material specification for the particular type or grade of alloy.

5.2.3.4.3 Material Inspection Program

Austenitic stainless steel materials with simple shapes need not be corrosion tested provided that the solution heat treatment is followed by water quenching. Simple shapes are defined as all plates, sheets, bars, pipe, and tubes, as well as forgings, fittings, and other shaped products which do not have inaccessible cavities or chambers that would preclude rapid cooling when water quenched. When testing is required, the tests are performed in accordance with ASTM A262, Practice A or E, as amended by Westinghouse Process Specifications 84201MW.

5.2.3.4.4 Prevention of Intergranular Attack of Unstabilized Austenitic Stainless Steels

Unstabilized austenitic stainless steels are subject to intergranular attack (IGA) provided that the following three conditions are present simultaneously:

1. An aggressive environment (an acidic aqueous medium containing chlorides or oxygen),

2. A sensitized steel, and

3. A high temperature.

If any one of the three conditions described previously is not present, IGA will not occur. Since high temperatures cannot be avoided in all components in the NSSS, Westinghouse relies on the elimination of Conditions 1 and 2 to prevent IGA on wrought stainless steel components.

The water chemistry in the RCS is rigorously controlled to prevent the intrusion of aggressive species. In particular, during power operation, the maximum permissible oxygen and chloride concentrations are 0.005 ppm and 0.15 ppm, respectively. Golik (1971) describes the precautions taken to prevent the intrusion of chlorides into the system during fabrication, shipping, and storage. The use of hydrogen overpressure precludes the presence of oxygen during operation. The effectiveness of these controls has been demonstrated by both laboratory tests and operating experience. The long time exposure of severely sensitized stainless steel in early plants to PWR coolant environments has not resulted in any sign of intergranular attack. Golik (1971) describes the laboratory experimental findings and the Westinghouse operating experience. The additional years of operations since the issuing of Golik (1971) have been further confirmation of the earlier conclusions. Severely sensitized stainless steels do not undergo any IGA in Westinghouse PWR coolant environments.

In spite of the fact that there has never been any evidence that PWR coolant water attacks sensitized stainless steels, Westinghouse considers it good metallurgical practice to avoid the use of sensitized stainless steels in the NSSS components. Accordingly, measures are taken to prohibit the purchase of sensitized stainless steels and to prevent sensitization during component fabrication. Wrought austenitic stainless steel stock used for components that are part of 1) the RCPB, 2) systems required for reactor shutdown, 3) systems required for emergency core cooling, and 4) reactor vessel internals (relied upon to permit adequate core cooling for normal operation or under postulated accident conditions) is utilized in one of the following conditions:

1. Solution annealed and water quenched, or

2. Solution annealed and cooled through the sensitization temperature range within less than approximately five minutes.

It is generally accepted that these practices will prevent sensitization. Westinghouse has verified this by performing corrosion tests on as-received wrought material.

Westinghouse recognizes that the heat affected zones of welded components must, of necessity, be heated into the sensitization temperature range, 800° to 1,500°F. However, severe sensitization, that is, continuous grain boundary precipitates of chromium carbide, with adjacent chromium depletion; can still be avoided by control of welding parameters and welding processes. The heat input* and associated cooling rate through the carbide precipation range are of primary importance. Westinghouse has demonstrated this by corrosion testing a number of weldments.

Of 25 production and qualification weldments tested, representing all major welding processes, and a variety of components, and

incorporating base metal thicknesses from 0.10 to 4.0 inches, only portions of 2 were severely sensitized. Of these, one involved a heat input of 120,000 joules, and the other involved a heavy socket weld in relatively thin walled material. In both cases, sensitization was caused primarily by high heat inputs relative to the section thickness.

Westinghouse controls the heat input in all austenitic boundary weldments by:

1. Prohibiting the use of block welding.

2. Limiting the maximum interpass temperature to 350°F.

3. Exercising approval rights on all shop welding procedures.

*Heat input is calculated according to the formula:

$$H = \frac{(E)\ (I)\ (60)}{S}$$

where :

H = joules/inch
E = volts
I = amperes
S = travel speed in inches/minute

To summarize, the program designed to prevent intergranular attack of austenitic stainless steel components includes:

1. Control of primary water chemistry to ensure a benign environment.

2. Utilization of materials in the final heat treated condition and the prohibition of subsequent heat treatments in the 800° to 1,500°F temperature range.

3. Control of welding processes and procedures to avoid heat-affected zone sensitization.

Both operating experience and laboratory experiments in primary water have demonstrated that this program is effective in preventing intergranular attack in Westinghouse NSSS's utilizing unstabilized austenitic stainless steel.

5.2.3.4.5 Retesting Unstabilized Austenitic Stainless Steels Exposed to Sensitization Temperatures

It is not normal Westinghouse practice to expose unstabilized austenitic stainless steels to the sensitization range of 800°F to 1,500°F during the fabrication into components. If during the course

of fabrication, the steel is inadvertently exposed to the sensitization temperature range, 800°F to 1,500°F, the material may be tested in accordance with ASTM A262, Practice A or E, as amended by Westinghouse Process Specification 84201MW, to verify that it is not susceptible to IGA, except that testing is not required for:

1. Cast metal or weld metal with a ferrite content of 5 percent or more.

2. Material with a carbon content of 0.03 percent or less that is subjected to temperatures in the range of 800°F to 1,500°F for less than one hour.

3. Material exposed to special processing provided the processing is properly controlled to develop a uniform product, and provided that adequate documentation exists of service experience and/or test data to demonstrate that the processing will not result in increased susceptibility to intergranular stress corrosion.

If it is not verified that such material is not susceptible to IGA, the material will be re-solution annealed and water quenched or rejected.

5.2.3.4.6 Control of Welding

The following paragraphs address Regulatory Guide 1.31, Control of Stainless Steel Welding, and present the methods used, and the verification of these methods, for austenitic stainless steel welding.

The welding of austenitic stainless steel is controlled to mitigate the occurrence of microfissuring or hot cracking in the weld. Although published data and experience have not confirmed that fissuring is detrimental to the quality of the weld, it is recognized that such fissuring is undesirable in a general sense. Also, it has been well documented in the technical literature that the presence of delta ferrite is one of the mechanisms for reducing the susceptibility of stainless steel welds to hot cracking. However, there is insufficient data to specify a minimum delta ferrite level below which the material will be prone to hot cracking. It is assumed that such a minimum lies somewhere between 0 and 3 percent delta ferrite.

The scope of these controls discussed herein encompasses welding processes used to join stainless steel parts in components designed, fabricated, or stamped in accordance with ASME Boiler and Pressure Vessel Code, Section III, Class 1, 2, and core support components. Delta ferrite control is appropriate for the previous welding requirements except where no filler metal is used or for other reasons such control is not applicable. These exceptions include

electron beam welding, autogenous gas shielded tungsten arc welding, and welding using fully austenitic welding materials.

The fabrication and installation specifications require welding procedure and welder qualification in accordance with Section III, and include the delta ferrite determinations for the austenitic stainless steel welding materials that are used for welding qualification testing and for production processing. Specifically, the undiluted weld deposits of the starting welding materials are required to contain a minimum of 5 percent delta ferrite (the equivalent ferrite number may be substituted for percent delta ferrite) as determined by chemical analysis and calculation using the appropriate weld metal constitution diagrams. When new welding procedure qualification tests are evaluated for these applications, including repair welding of raw materials, they are performed in accordance with the requirements of Sections III and IX.

The results of all the destructive and nondestructive tests are reported in the procedure qualification record in addition to the information required by Section III.

The starting welding materials used for fabrication and installation welds of austenitic stainless steel materials and components meet the requirements of Section III. The austenitic stainless steel welding material conforms to weld metal analysis A-7 (designated A-8 in the 1974 Edition of the ASME Code), Type 308 or 308L for all applications. Bare weld filler metal, including consumable inserts, used in inert gas welding processes conform to ASME SFA-5.9, and are procured to contain not less than 5 percent delta ferrite according to Section III. Weld filler metal materials used in flux shielded welding processes conform to ASME SFA-5.4 or SFA-5.9 and are procured in a wire-flux combination capable of providing not less than 5 percent delta ferrite in the deposit according to Section III. Welding materials are tested using the welding energy inputs to be employed in production welding.

Combinations of approved lots heats and of starting welding materials are used for all welding processes. The welding quality assurance program includes identification and control of welding material by lots and heats as appropriate. All of the weld processing is monitored according to approved inspection programs which include review of starting materials, qualification records, and welding parameters. Welding systems are also subject to a quality assurance audit that includes the following:

1. Calibration of gages and instruments,

2. Identification of starting and completed materials,

3. Welder and procedure qualifications,

4. Availability and use of approved welding and heat treating procedures, and

5. Documentary evidence of compliance with materials, welding parameters, and inspection requirements.

Fabrication and installation welds are inspected using nondestructive examination methods according to Section III rules.

To assure the reliability of these controls, Westinghouse has completed a delta ferrite verification program, described in (Enrietto 1974) which has been approved as a valid approach to verify the Westinghouse hypothesis and is considered an acceptable alternative for conformance with the USNRC Interim Position on Regulatory Guide 1.31. The Regulatory Staff's acceptance letter and topical report evaluation were received on December 30, 1974. The program results, which support the hypothesis presented in Enrietto (1974), are summarized in Enrietto (1976).

The criteria concerning delta ferrite determinations discussed above were incorporated in the BVPS-2 components that were involved in the Westinghouse verification program, although these components cannot necessarily be identified. Those components not involved in the verification program were fabricated in accordance with the applicable ASME Code requirements (Table 5.2-1) which do not include delta ferrite determinations. Therefore, the delta ferrite determinations performed on the BVPS-2 components are in addition to the applicable ASME Code requirements.

Section 1.8 provides discussions which indicate the degree of conformance of the austenitic stainless steel components of the RCPB with Regulatory Guides 1.34, Control of Electroslag Properties, and 1.71, Welder Qualification for Areas of Limited Accessibility.

5.2.4 Inservice Inspection and Testing of Reactor Coolant Pressure Boundary

5.2.4.1 Scope of Inservice Inspection and Testing Program

The reactor coolant pressure boundary consists of ASME Section III, Class 1 components including the reactor pressure vessel, system piping, pumps, valves, and other components which require inservice inspection and/or testing, as defined by ASME Section XI and the ASME OM Code and any augmented programs required by the regulatory agencies. All components are designed, fabricated, and erected to be inspectable to the requirements of ASME Section XI, 1980 Edition up to and including Winter 1980 addenda. The RCS and components are discussed in Chapter 5.

5.2.4.2 Provisions for Access to Reactor Coolant Pressure Boundary

System and components which require inspection in accordance with ASME Section XI are designed to have physical access adequate to allow inspection as prescribed by Subarticle IWA-1500.

The reactor vessel is designed, fabricated, and erected to comply fully with the inservice inspection requirements of ASME Section XI. The internal surface of the reactor vessel can be inspected using visual and nondestructive techniques. During refueling, the vessel cladding can be inspected between the closure flange and the primary coolant inlet nozzles. When the entire vessel is to be inspected, the core barrel can be removed, making the entire inside vessel surface accessible.

The closure head can be visually examined during refueling. Optical devices allow a selective inspection of the cladding, control rod drive mechanism nozzles, and the gasket seating surface. The outer surface of the knuckle transition piece (the area of highest stress of the closure head) is accessible for visual inspection, dye penetrant, and magnetic particle and ultrasonic testing. Removable closure studs can be inspected periodically using visual, magnetic particle and/or ultrasonic technique. Per ASME Section XI, Table IWB-2500-1, a volumetric examination is all that is required for studs that remain in place.

The installed irradiated reactor vessel items required to be inspected per Section XI, Table IWB-2500-1, are available for visual and nondestructive inspection. All welds which require volumetric examinations are finished and contoured to permit meaningful ultrasonic examinations.

The following design considerations are incorporated into the system design to permit the required inspections per Section XI, Table IWB-2500-1:

1. All reactor internals are completely removable. The tools and storage space required to permit these inspections are provided.

2. The closure head is stored dry on the reactor head storage stand during refueling to facilitate direct visual inspection.

3. All removable reactor vessel studs, nuts, and washers are removed to dry storage during refueling.

Due to radiation levels and remote underwater accessibility limitations, the following steps have been incorporated into the vessel design and manufacturing procedures to facilitate performance of the periodic nondestructive examinations required by ASME Section XI:

1. Shop ultrasonic examinations are performed on all internally clad surfaces to assure an adequate cladding bond to allow

later ultrasonic examination of the base metal from the inside surface.

2. The reactor vessel shell is designed as a clean, uncluttered, cylindrical surface to permit future positioning of examination equipment without obstruction.

3. The weld-deposited clad surfaces on both sides of welds to be inspected are specifically finished and contoured to assure meaningful ultrasonic examination.

The steam generator is designed to permit inservice inspection of both the Class 1 and 2 portions, as required in ASME Section XI, Tables IWB-2500-1 and IWC-2500-1. Welds which require volumetric examinations are finished and contoured to permit meaningful ultrasonic examinations. Two man-ways in the lower head, one on each side of the divider plate, provide access to permit examination of the Code Class 1 lower head interior and tube sheet, and to permit eddy current examination of the steam generator tubes.

The pressurizer is designed, fabricated, and erected to comply fully with the inservice inspection requirements of ASME Section XI, Table IWB-2500-1. To satisfy these requirements, the welds specified in Table IWB-2500-1 are finished and contoured to permit meaningful ultrasonic examinations.

To maintain a uniform geometry for ultrasonic inspection, the liner within the spray line nozzle region extends beyond the weld region. Removable insulation is provided to permit ultrasonic examination of all welds listed in ASME Section XI, Table IWB-2500-1. A man-way provided in the top head permits access for internal inspection of the pressurizer.

Piping systems are designed so that all welds requiring volumetric (ultrasonic) examination are physically accessible for ultrasonic equipment. Adequate space around pipes at these welds, and removable insulation and shielding, allow this access. The surface of all welds requiring ultrasonic examination are smoothed and contoured to permit meaningful ultrasonic examination. The above mentioned access and contour stipulations apply to all items listed in ASME Section XI, Tables IWB-2500-1 and IWC-2500-1.

Piping systems requiring surface or visual examination as stipulated in ASME Section XI, Tables IWB-2500-1 and IWC-2500-1, are designed to allow adequate access and visibility. Inservice inspection access to major RCS components (excluding the reactor vessel) is provided as follows:

1. Working platforms or space for temporary scaffolds are provided to facilitate access to inspection areas.

2. Removable insulation on component and piping welds and adjacent base metal is designed for easy removal and replacement in areas where external inspection is planned.

3. Removable floor sections are provided above the RCPs to permit removal of the pump motor for internal inspection of the pumps.

4. The reactor coolant loop compartments are designed with access for personnel to permit direct inspection of the external portion of the piping and components during refueling operations.

5.2.4.3 Examination Techniques and Procedures

As defined by ASME Section XI, Subarticle IWA-2200, examination techniques fall into three major categories:

1. Visual examinations are performed directly where possible. Depending on the type and degree of obstruction encountered and where direct access to the examination area is limited or impossible, various visual aids and instruments (mirrors, borescopes, fiber optics, and remotely-operated television cameras) are employed. All visual examination techniques and procedures meet the requirements of ASME Section XI, Subarticle IWA-221O.

2. Surface examinations are performed using either dye penetrant or magnetic particle techniques and procedures, as defined by ASME Section XI, Subarticle IWA-2200.

3. All volumetric examination techniques and procedures performed by either manual means or remotely-controlled automated devices are conducted in accordance with the requirements of ASME Section XI, Subarticle 2230. The reactor pressure vessel is inspected by a remotely-operated internal examination device capable of reaching shell and nozzle-to-shell welds. Alternate examination techniques and procedures may be used, provided the requirements of ASME Section XI, Subarticle IWA-2240 are met.

4. Examination results are compared against the baseline inspection data done prior to plant start-up as described in Chapter 14.

5.2.4.4 Inspection Intervals

As defined by Inspection Program B of ASME Section XI, Subarticle IWA-2420, inservice inspection will be in 10 year intervals, with each interval divided into three 40 month inspection periods. The interval and periods may be extended by as much as 1 year to permit inspections to be concurrent with plant outages.

The inspection interval during which a continuous outage of 6 months or longer has occurred, may be extended for a period equivalent to the outage. The in-service inspection performed during each interval shall be as specified for those components identified in Tables IWB-2500-1 and IWC-2500-1. The extent and frequency of examinations and permissible deferrals are also as specified in ASME Section XI, Tables IWB-2500-1 and IWC-2500-1. Any repairs at this time will be done in accordance with ASME Section XI, Articles IWA-4000 and IWB-4000. Any replacements will be done in accordance with ASME XI, Articles IWA-4000 and IWB-4000. A description of preservice inspection requirements for the RCS pressure boundary is given in Chapter 14.

5.2.4.5 Inservice Inspection Program Categories and Requirements

As specified by ASME Section XI, Subsection IWB, Table IWB-2500-1, all ASME Section III, Class 1 components are subject to inservice inspection and testing. The inservice inspection program (Chapter 16) defines specific categories and requirements.

5.2.4.6 Evaluation of Examination Results

Examination results are evaluated in full accordance with the provisions of ASME Section XI, Article IWB-3000.

5.2.4.7 System Leakage and Hydrostatic Pressure Tests

System leakage tests are performed in accordance with the requirements of ASME Section XI, Articles IWA-5000, and IWB-5000. Hydrostatic pressure tests will be performed in accordance with NRC authorized methods. System operating limits are defined in the Technical Specifications presented in Chapter 16.

5.2.5 Detection of Leakage Through Reactor Coolant Pressure Boundary

By monitoring containment sump level and flow, containment airborne radioactivity, and containment atmospheric pressure, temperature, and humidity, abnormal leakage from the RCPB can be detected and identified. These methods meet the requirements of General Design Criteria 2 and 30 (Section 3.1.2.3a). Operating experience has indicated that the average long-term leakage (from sampling losses, collected leakoffs, and unidentified leakage to the containment) from the RCS is between 0.1 and 0.3 gpm. Regulatory Guide 1.45 is also a design basis (Section 1.8).

5.2.5.1 Collection of Identified Leakage

Leakoffs and collection tanks from RCPB components (valve stems, RCP shaft seals, pressurizer relief valves, and reactor vessel flange leakoff) collect the limited amount of leakage that is expected.

RCPB valves larger than 2 1/2 inches have valve stem leakoff connection. Excessive leakage from a valve stem leakoff line increases the rate of fluid collection in the primary drains transfer tank (PDTT). Increases in the PDTT level indicate the magnitude of the leak.

Any one, or a combination, of the following indications or alarms will identify a RCP mechanical seal leak:

1. High seal water temperature at the outlet of the seal water heat exchanger (local indicator),

2. High level in the RCP seal standpipe (alarm in main control room),

3. Increasing level in the PDTT, indicating the magnitude of the leak (indication in main control room),

4. Increased temperature of RCP No. 1 seal leakoff water returning to the seal water heat exchanger (indication in main control room), or

5. High flow rate of the seal water leaving the RCP (alarm in main control room).

High temperature downstream of the affected relief valve (alarm in the main control room) identifies a reduction of coolant inventory as a result of seat leakage through a pressurizer safety relief valve or a PORV. The PRT (high level alarm in the main control room) collects this leakage.

Reactor vessel flange leakage is collected in the PDTT and indicated by high temperature in the flange leakoff line (alarm in the main control room). Leakage from this pathway is monitored by the alarm function which annunciates if the temperature detector in the head flange leakoff line reaches a predetermined temperature. Leakage from this pathway is accounted for since this leakage is collected in the PDTT which is included in the RCS water inventory balance determinations.

5.2.5.2 Collection and Monitoring of Unidentified Leakage

Containment sumps collect RCPB leakage which is not collected in the PDTT or in the PRT.

5.2.5.3 Leakage Detection Methods

The following methods are utilized to detect leakage:

1. Containment atmosphere particulate radioactivity monitoring,

2. The containment narrow range sump level and sump pump flow monitoring,

3. Containment atmosphere gaseous radioactivity monitoring, and

4. Containment pressure, temperature, and humidity monitoring.

Procedures to identify the leakage source upon a change in the unidentified leakage rate into the sump include, but are not limited to one or more of the following:

1. Check for changes in airborne radiation monitor indications,

2. Sample and analyze containment atmosphere for radioactivity,

3. Check for changes in containment humidity, pressure, and temperature,

4. Check makeup rate to the RCS for abnormal increase,

5. Check for changes in water levels and other parameters in systems which could leak water into the containment, and

6. Review logs for maintenance operations which may have discharged water into the containment.

5.2.5.4 Intersystem Leakage

Even though substantial intersystem leakage from the RCPB to other systems across passive barriers or valves is not expected, possible leakage points and their methods of detection are considered. One, or a combination, of the following identifies steam generator tube and tube sheet leaks (Section 11.5):

1. High activity, as monitored and alarmed in the air ejector condenser vent line,

2. Steam generator secondary side radioactivity, as sampled and monitored via the steam generator blowdown line,

3. Secondary side radioactivity, as measured in a steam generator sample, for example, by the tritium balance method to determine the magnitude of the leak, or

4. Radioactivity, boric acid (in excess of secondary side boric acid additions, if additions are being made), or conductivity in condensate (for example, from main steam line drain traps), as indicated by laboratory analysis.

An increase in temperature, pressure, or flow in the component cooling water lines servicing the RCP thermal barrier indicates intersystem leakage to the primary component cooling water system at the RCP thermal barrier. Increasing flow or pressure automatically isolates the component cooling water return from the thermal barrier and sets off an alarm in the main control room. In addition, the main primary component cooling water header is continuously monitored for radioactivity.

Monitoring safety injection accumulator level and periodic sampling of the accumulators and other piping connecting to the RCS can detect intersystem leakage to the safety injection system.

Periodic sampling of the cooling water systems can also detect intersystem leakage to the secondary sides of the residual heat removal heat exchangers, letdown line heat exchangers, and the reactor coolant pump seal water heat exchangers.

5.2.5.5 Sensitivity and Response Time

Reactor coolant pressure boundary leak detection methods include the following sensitivities and response times.

5.2.5.5.1 Containment Atmosphere Radioactivity Monitoring

The containment atmosphere radioactivity monitoring system is designed to meet seismic requirements. The containment airborne radiation monitors (gas and particulate) have the sensitivities ($1x10^{-10}$ to $1x10^{-1}$ μCi/cc) recommended in Regulatory Guide 1.45, and respond rapidly to abnormal RCPB leakage. The sensitivity will detect 1 gpm of leakage in less than 1 hour, given an RCS activity equivalent to that assumed in the design calculations for the monitors. The response times are a function of the rate of leakage, reactor coolant concentration, and containment background radiation level.

5.2.5.5.2 Containment Sump Level

Two leakage monitoring systems are provided in the containment sump. One system, which is not seismically designed, uses the flow indication of the sump pumps to determine leak rates. The system meets the sensitivity requirements of normal plant operation, 1 gpm in 1 hour. Accuracy of detecting a 1 gpm leak in 1 hour is achieved by the programmable controller which periodically establishes flow rate from the sump pumps and monitors pump operating times to measure a leak rate into the sump.

The second system uses changes in the water level of the containment sump to determine leak rate. Water level in the sump is continuously monitored during normal plant operation by narrow range QA Category I, Seismic Category I, Class 1E level instruments in both the incore instrumentation sump and containment sump. The system is capable of detecting a 5 gpm leak in 1 hour. A high level condition in any sump will be indicated and alarmed in the main control room. Post-accident monitoring of containment sump water level is described in Section 7.5.

5.2.5.5.3 Containment Pressure, Temperature, and Humidity

RCPB leakage increases containment pressure, temperature, and humidity, values which are indicated and recorded in the main control room. A 5 gpm leak rate can be detected in less than 1 hour.

5.2.5.6 Seismic Capability of Systems

Following a seismic event, containment airborne radiation monitoring, along with containment sump and incore instrumentation sump level monitoring, will remain operable and are capable of detecting a 5 gpm leak in one hour. These instruments provide redundant means of detecting any abnormal leakages following a seismic event. The level instruments are Class 1E, QA Category I designed to Seismic Category I requirements, and provide remote indication and alarms in the main control room.

5.2.5.7 Indicators and Alarms

Each leakage detection system has indicators and alarms in the main control room. The operators will follow established procedures in the event these devices give indication of RCPB leak.

The following indicators and/or alarms are located in the main control room to detect RCPB leakage:

1. Containment air particulate and gaseous high radiation indicators with alarms and a means of converting these signals to units of water flow,

2. Containment sump narrow range level indication and high level alarm, and in-core instrumentation sump narrow range indication and high level alarm,

3. Containment temperature and humidity indication, partial pressure indication, and alarm,

4. Nonseismic containment sump and incore instrumentation sump high level alarm, and

5. Programmable controller that alarms at unidentified leakage greater than 1 gpm (60 gallons integrated over one hour).

Section 7.5 further describes safety-related indicating devices.

5.2.5.8 Testing and Calibration

The testing and instrument calibration programs for containment pressure, temperature, and humidity, containment sump level, and containment radiation monitoring are described in Sections 7.5, 9.3.3, and 12.3.4, respectively.

5.2.5.9 Technical Specifications

Chapter 16 describes the Technical Specifications for the RCPB leakage detection systems.

5.2.6 References for Section 5.2

Burnett, T. W. T., et al, 1972. LOFTRAN Code Description. WCAP-7907.

Cooper, K., et al, 1972. Overpressure Protection for Westinghouse Pressurized Water Reactors. WCAP-7769 Revision 1 (also letter NS-CE-622, dated April 16, 1975, C. Eicheldinger (Westinghouse) to D. B. Vassallo (NRC), additional information on WCAP-7769, Revision 1).

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Enrietto, J. F. 1974. Control of Delta Ferrite in Austentic Stainless Steel Weldments. WCAP-8693.

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Westinghouse Electric Corporation 1978. Dynamic Fracture Toughness of ASME SA 508 Class 2a and ASME SA535 Grade A Class 2 Base and Heat Affected Zone Material and Applicable Weld Metal. WCAP-9292.

Tables for Section 5.2

TABLE 5.2-1

AMERICAN SOCIETY OF MECHANICAL ENGINEERS (ASME)
CODE ADDENDA FOR RCS COMPONENTS

This table has been intentionally deleted from the UFSAR.

The information is now contained in the ASME Code Baseline Document (refer to Section 3.2.2.4.1).

TABLE 5.2-2

ASME III CLASS 1 PRIMARY COMPONENTS
MATERIAL[1] SPECIFICATIONS

Components	Specification[1]
Reactor Vessel	
Shell & head plates (other than core region)	SA533 Gr B, Class 1 (vacuum treated)
Shell plates (core region)	SA533 Gr B, Class 1 (vacuum treated)
Shell, flange ends & nozzle Forgings	SA508 Class 2
Nozzle safe ends	SA182 Type F316
CRDM tube	SB166 or SB167
CRDM head adapter	SA182 Type F304
Incore instrumentation tubes	SB166
Closure studs, nuts, washers	SA-540 Gr B-23 and B-24 Class 3
Inserts support and adaptors Clevis inserts, and lock Bars (internals)	SB166 with 0.10% carbon
Leakoff monitor tubes and	SB166 SA182F316 SA312F316
Head vent pipe	SB166 SB167
Vessel supports, seal ledge And heating lifting lugs	SA516 Gr 70 quenched & tempered lugs or SA533 Gr A, B, or C, Class 1 or 2.
(Vessel supports may be of weld metal buildup of strength equivalent to nozzle material.)	
Cladding & buttering	Stainless steel weld metal analysis A-7[2] and Ni-Cr-Fe weld metal F-number 43
Clevis inserts bolts (internals)	SA634, Grade 688, Type 2
Steam Generator	
Pressure plates	SA533 Gr A, B, or C, Class 1 or 2
Pressure forgings (including nozzles and tubesheet)	SA508 Class 2, 2a, or 3, or SA216 Grade WCC
Nozzle safe ends	Stainless steel weld metal analysis A-7[2] and Ni-Cr-Fe weld metal F-Number 43

TABLE 5.2-2 (Cont.)

Components	Specification[1]
Channel heads	SA533 Gr A, B, or C, Class 1 or 2, or SA216 Grade WCC
Tubes	SB163 Ni-Cr-Fe, annealed
Cladding and buttering	Stainless steel weld metal analysis A-7[2] and Ni-Cr-Fe weld metal F-Number 43
Closure bolting	SA192 Gr B-7
Pressurizer Components	
Pressure plates	SA533 Gr A Class 2
Pressure forgings	SA508 Class 2A
Nozzle safe ends	SA182 Type 316L and Ni-Cr-Fe weld metal F-number 43
Cladding and buttering	Stainless steel weld metal analysis A-8 and Ni-Cr-Fe weld metal F-number 43
Closure bolting	SA193 Gr B-7
Reactor Coolant Pump	
Pressure forgings	SA182 F-304/F-316/F-347/F-348
Pressure casting	SA351 Gr CF8, CF8A, or CF8M
Tube & pipe	SA213, SA376 or SA312 seamless Type 304/316
Pressure, plates	SA240 Type 304/316
Bar material	SA479 Type 304/316
Closure bolting	Gr B7, SA540, Gr B24, Gr 660
Flywheel	SA533 Gr B and Class 1
Reactor Coolant Piping	
Reactor coolant pipe (Centrifugal casting)	SA376 Gr 304N or SA351 Gr CF8A
Reactor coolant fittings	SA351 Gr CF8A
Branch nozzles	SA182 Gr 304N (Code Case 1423-2)
Surge line & loop bypass	SA376 Gr 304/316/304N (Code Case 1423-2)

TABLE 5.2-2 (Cont.)

Components	Specification[1]
Auxiliary piping 1/2 in Through 12 ft and wall Schedules 40S through 80S (ahead of second isolation valve)	ANSI B36.19
All other auxiliary piping (ahead of second isolation valve) socket	ANSI B36.10
Weld fittings	ANSI B16.11
Piping flanges	ANSI B16.5
Full Length Control Rod Drive Mechanism	
Latch housing	SA182 Gr F304 or SA351 Gr CF8
Rod travel housing	SA182 Gr F304, SA336, Gr F8, or SA312 TP 304
Cap	SA479 Type 304
Welding materials	Stainless steel weld metal analysis A-8

NOTES:

(1) Materials listed in this table may have been replaced with materials of equivalent design characteristics. The term equivalent is described in UFSAR Section 1.12, “Equivalent Materials”.

(2) Designated A-8 in ASME IX, 1974 edition of the Code.

TABLE 5.2-3

ASME III CLASS 1 AND 2 AUXILIARY COMPONENTS MATERIAL[1] SPECIFICATIONS

Components	Specification[1]
Valves	
Bodies	SA182 Type F316 or SA351 Gr CF8/CF8M
Bonnets	SA182 Type F316 or SA351 Gr CF8/CF8M
Discs	SA182 Type F316, SA564 Gr 630, SA351 Gr CF8/CF8M
Pressure retaining bolting	SA453 Gr 660
Pressure retaining nuts	SA453 Gr 660 SA194 Gr 6
Auxiliary Heat Exchangers	
Heads	SA240 Type 304
Nozzle necks	SA182 Gr F304, SA312 Type 304 SA240 Type 304
Tubes	SA213 Type 304, SA240 Type 304
Tube Sheets	SA182 Gr F304, SA240 Type 304, SA516 Gr 70 with stainless steel weld metal analysis A-7[2] cladding
Shells	SA240 SA312 Type 304
Shells & heads	SA240 Type 304 or SA264 consisting of SA537 Class 1 with stainless steel weld metal analysis A-8 cladding
Flanges & nozzles	SA182 Gr F304, SA105 or SA350 Gr LF2/LF3 with stainless steel Weld metal analysis A-8 cladding
Piping	SA312 SA240 Type 304/Type 316 Seamless
Pipe fittings	SA403 WP304 seamless
Closure bolting & nuts	SA193 Gr B7 or SA194 Gr 2H or SA194 Gr 7.

TABLE 5.2-3 (Cont)

Components	Specification[1]
Auxiliary Pumps	
Pump casing & heads	SA351 Gr CF8/CF8M SA182 Gr F304/F316
Flanges and nozzles	SA182 Gr F304/F316 SA403 Gr WP316L seamless
Piping	SA312 Type 304/Type 316 seamless
Stuffing of packing box cover	SA351 Gr CF8/CF8M or SA240 Type 304/Type 316
Pipe fittings	SA403 Gr WP316L seamless
Closure bolting	SA193 Gr B6, B7 or B8M, SA194 Gr2H/Gr 8M, SA193 Gr F6, B7, or B8M or SA453 Gr 660; and nuts, SA194 Gr 2H/7, Gr 8M, and Gr 6
Closure nuts	SA194 Gr 2H/8M/6/7

NOTES:

(1) Materials listed in this table may have been replaced with materials of equivalent design characteristics. The term equivalent is described in UFSAR Section 1.12, “Equivalent Materials”.

(2) Designated A-8 in ASME IX, 1974 edition of the Code.

TABLE 5.2-4

REACTOR VESSELS INTERNALS FOR EMERGENCY CORE COOLING SYSTEMS

Components	Specification(1)
Forgings	SA182 Type F304
Plates	SA240 Type 304
Pipes	SA312 Type 304 seamless or SA376 Type 304
Tubes	SA213 Type 304
Bars	SA479 Type 304/410
Castings	SA351 Gr CF8/CF8A
Bolting	SA193 Gr B8M (65 MYS/90 MTS) (Code Case 1618), Inconel 750, SA461 Gr 688
Nuts	SA193 Gr B-8
Locking devices	SA479 Type 304
Guide tube split pins	SA637, Grade 688, Type 2
Roto-Lok inserts	SA637, Grade 688, Type 2

NOTES:

(1) Materials listed in this table may have been replaced with materials of equivalent design characteristics. The term equivalent is described in UFSAR Section 1.12, "Equivalent Materials".

TABLE 5.2-5

SPECIFICATIONS AND GUIDELINES FOR THE REACTOR COOLANT SYSTEM DURING POWER OPERATION

Specification Parameters	Value
Dissolved Oxygen	Refer to BVPS-2 Licensing Requirements Manual.
Chloride, ppb	Refer to BVPS-2 Licensing Requirements Manual.
Fluoride, ppb	Refer to BVPS-2 Licensing Requirements Manual.
Boric Acid, as ppm B*	Refer to BVPS-2 Chemistry Manual.
Lithium, ppm as Li^7	Refer to BVPS-2 Chemistry Manual.
Hydrogen, cc (STP)/kg H_2O**	Refer to BVPS-2 Chemistry Manual.

Guideline Parameters	Value
Conductivity, µS/cm at 77°F	Refer to BVPS-2 Chemistry Manual.
pH at 77°F	Refer to BVPS-2 Chemistry Manual.
Silica, ppb	Refer to BVPS-2 Chemistry Manual.
Suspended Solids, ppb***	Refer to BVPS-2 Chemistry Manual.
Aluminum, ppb	Refer to BVPS-2 Chemistry Manual.
Calcium + Magnesium, ppb	Refer to BVPS-2 Chemistry Manual.
Magnesium, ppb	Refer to BVPS-2 Chemistry Manual.

TABLE 5.2-5 (Cont)

NOTES:

* Reactor power operation with a coolant boron concentration greater than 1200 ppm requires review and approval by appropriate personnel. High burnup cores falling into this category should not be taken critical until appropriate personnel have given approval for operation.

** Hydrogen must be present in the reactor coolant for all plant operations with nuclear power above 1 MWt thermal. The normal operating range should be 25-50 cc/kg (STP)H_2O. Note: It is recommended that a hydrogen concentration of at least 15cc/kg (STP)H_2O be established in the reactor coolant prior to achieving criticality.

*** Solids concentration determined by filtration through a filter having 0.45 micron pore size. The 200 ppb limit is to be met following dilution to criticality.

5.3 REACTOR VESSEL

5.3.1 Reactor Vessel Materials

5.3.1.1 Material Specifications

Material specifications are in accordance with the ASME Code requirements and are given in Section 5.2.3.

The ferritic materials of the reactor vessel beltline are restricted to the following maximum limits of copper and phosphorus to reduce sensitivity to irradiation embrittlement in service:

Element	Base Metal (%)	As Deposited Weld Metal (%)
Copper	0.10 (Ladle) 0.12 (Check)	0.10
Phosphorus	0.012 (Ladle) 0.017 (Check)	0.020

5.3.1.2 Special Processes Used for Manufacturing and Fabrication

1. The vessel is Safety Class 1. Design and fabrication of the reactor vessel is carried out in strict accordance with ASME Code, Section III, Class 1. The head and vessel flanges and nozzles are manufactured as forgings. The cylindrical portion of the vessel is made up of several shells, each consisting of formed plates joined by full penetration longitudinal and girth weld seams. The hemispherical heads are made from dished plates. The reactor vessel parts are joined by welding, using the single or multiple wire submerged arc and the shielded metal arc process.

2. The use of severely sensitized stainless steel as a pressure boundary material has been prohibited and has been eliminated by either a select choice of material or by programming the method of assembly.

3. The control rod drive mechanism (CRDM) head adaptor threads and surfaces of the guide studs are chrome-plated to prevent possible galling of the mated parts.

4. At all locations in the reactor vessel where stainless steel and Inconel are joined, the final joining beads are Inconel weld metal in order to prevent cracking.

5. Core region shells fabricated of plate material have longitudinal welds which are angularly located away from the peak neutron exposure experienced in the vessel, where possible.

6. The location of full penetration weld seams in the upper closure head and vessel bottom head are restricted to areas that permit access during inservice inspection.

7. The stainless steel clad surfaces are sampled to assure that composition requirements are met.

8. The procedure qualification for cladding low alloy steel (SA508 Class 2) requires a special evaluation to assure freedom from underclad cracking.

9. Minimum preheat requirements have been established for pressure boundary welds using low-alloy material. The preheat is maintained either until (at least) an intermediate post weld heat treatment is completed or until the completion of welding. In the latter case, upon completion of welding, a low temperature (400°F minimum) post weld heat treatment is applied for four hours followed by allowing the weldment to cool to ambient temperature. This practice is specified for all pressure boundary welds except for the installation of nozzles. For the primary nozzle to shell welds, the preheat temperature is maintained until a high temperature (greater than 800°F) post-weld heat treatment is applied in accordance with the requirements of the ASME Code, Section III. This method is followed because higher restraint stresses may be present in the nozzle-to- shell weldments.

5.3.1.3 Special Methods for Nondestructive Examination

The nondestructive examination of the reactor vessel and its appurtenances is conducted in accordance with the ASME Code, Section III requirements. Numerous examinations are also performed in addition to formal ASME Code, Section III requirements. Nondestructive examination of the vessel is discussed in the following paragraphs and the reactor vessel QA program is given in Table 5.3-3.

5.3.1.3.1 Ultrasonic Examinations

1. In addition to the design code straight beam ultrasonic test, angle beam inspection over 100 percent of one major surface of plate material is performed during fabrication to detect discontinuities that may be undetected by the straight beam examination.

2. In addition to ASME Code, Section III nondestructive examination, all full penetration ferritic pressure boundary welds in the reactor vessel are ultrasonically examined during fabrication. This test is performed upon completion of the welding and intermediate heat treatment but prior to the final post-weld heat treatment.

3. After hydrotesting, all full penetration ferritic pressure boundary welds in the reactor vessel, as well as the nozzle to safe end welds, are ultrasonically examined. These inspections are also performed in addition to the ASME Code, Section III nondestructive examinations.

5.3.1.3.2 Penetrant Examinations

1. The partial penetration welds for the CRDM head adaptors and the bottom instrumentation tubes are inspected by dye penetrant after the root pass in addition to Code requirements. Core support block attachment welds are inspected by dye penetrant after the first layer of weld metal and after each additional 1/2 inch of weld metal.

2. Surface Examinations

   a. Dye penetrant examinations are performed on all clad surfaces and other vessel and head internal surfaces after the hydrostatic test.

   b. Base metal or weld surfaces which are exposed to mechanical or thermal straightening operations are dye penetrant examined immediately after this operation.

5.3.1.3.3 Magnetic Particle Examination

The following magnetic particle examination requirements are in addition to those of the ASME Code, Section III.

All magnetic particle examinations of materials and welds shall be performed in accordance with the following:

1. Prior to the final post-weld heat treatment - only by the prod, coil, or direct contact method.

2. After the final post-weld heat treatment - only by the yoke method.

The following surfaces and welds are examined by magnetic particle methods. The acceptance standards are in accordance with the ASME Code, Section III.

<u>Surface Examinations</u>

1. Magnetic particle examination of all exterior vessel and head surfaces after the hydrostatic test.

2. Magnetic particle examination of all exterior closure stud surfaces and all nut surfaces after final machining or rolling. Continuous circular and longitudinal magnetization are used.

3. Magnetic particle examination of all inside diameter surfaces of carbon and low-alloy steel products that have their properties enhanced by accelerated cooling. This inspection is performed after forming and machining (if performed) and prior to cladding.

Weld Examination

The weld metal buildup for vessel supports, and welds attaching the closure head lifting lugs and refueling seal ledge to the reactor vessel are examined by magnetic particle examination after the first layer and after each additional 1/2 inch of weld metal is deposited. All pressure boundary welds are examined after back chipping or back grinding operations.

5.3.1.4 Special Controls for Ferritic and Austenitic Stainless Steels

Welding of ferritic steels and austenitic stainless steels is discussed in Section 5.2.3. Section 5.2.3.4 includes discussions which indicate the degree of conformance with Regulatory Guide 1.44, Control of the Use of Sensitized Stainless Steel, and Regulatory Guide 1.31, Control of Stainless Steel Welding. Section 1.8 discusses the degree of conformance with Regulatory Guides 1.43, Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components; 1.50, Control of Preheat Temperature for Welding of Low-Alloy Steels; 1.71, Welder Qualification for Areas of Limited Accessibility; 1.99, Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials; and 1.37, Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants. Regulatory Guide 1.34, Control of Electroslag Weld Properties, is not applicable since there are no electroslag welds in the reactor vessel.

5.3.1.5 Fracture Toughness

Assurance of adequate fracture toughness of ferritic materials in the reactor vessel (ASME Section III Class I Component) is provided by compliance with the requirements for fracture toughness testing included in NB 2300 to Section III of the ASME Boiler and Pressure Vessel Code (1971 Edition through Summer 1972 Addendum) and Appendix G of 10 CFR 50.

The initial Charpy V-notch minimum upper shelf fracture energy levels for the reactor vessel beltline (including welds) are 75 ft/lb as required in accordance with Appendix G of 10 CFR 50.

Reactor vessel fracture toughness data are given in Table 5.3-1.

During plant heatup and cooldown the rates of temperature and pressure changes are limited to meet 10CFR50, Appendix G fracture

toughness requirements. The pressure temperature limits are further discussed in Section 5.3.2.

A discussion of the Pressurized Thermal Shock (PTS) rule is contained in Section 5.3.3.6.

5.3.1.6 Material Surveillance

In the surveillance program, the evaluation of the radiation damage is based on pre-irradiation testing of Charpy V-notch and tensile specimens and post-irradiation testing of Charpy V-notch, tensile and 1/2 T (thickness) compact tension (CT) fracture mechanics test specimens. The program is directed toward evaluation of the effect of radiation on the fracture toughness of reactor vessel steels based on the transition temperature approach and the fracture mechanics approach. The program will conform with 10 CFR 50, Appendix H.

The reactor vessel surveillance program uses six specimen capsules. The capsules are located in guide baskets welded to the outside of the neutron shield pads and are positioned directly opposite the center portion of the core. The capsules can be removed when the vessel head is removed and can be replaced when the internals are removed. The six capsules contain reactor vessel steel specimens, oriented both parallel and normal (longitudinal and transverse) to the principal rolling direction of the limiting base material located in the core region of the reactor vessel and associated weld metal and weld heat affected zone metal. The six capsules contain 54 tensile specimens, 360 Charpy V-notch specimens (which include weld metal and weld heat affected zone material), and 72 CT specimens. Archive material sufficient for two additional capsules will be retained.

Dosimeters, including Ni, Cu, Fe, Co-Al, Cd shielded Co-Al, Cd shielded Np-237, and Cd shielded U-238, are placed in filler blocks drilled to contain them. The dosimeters permit evaluation of the flux seen by the specimens and the vessel wall. In addition, thermal monitors made of low melting point alloys are included to monitor the maximum temperature of the specimens. The specimens are enclosed in a tight fitting stainless steel sheath to prevent corrosion and ensure good thermal conductivity. The complete capsule is helium leak tested. As part of the surveillance program, a report of the residual elements in weight percent to the nearest 0.01 percent will be made for surveillance material and as deposited weld metal.

Each of the six capsules contains the following specimens:

Material	Number of Charpy V-Notch Specimens	Number of Tensile Specimens	Number of CT Specimens
Plate B9004-2*	15	3	4
Plate B9004-2**	15	3	4

Material	Number of Charpy V-Notch Specimens	Number of Tensile Specimens	Number of CT Specimens
Weld Metal***	15	3	4
Heat Affected Zone (Plate B9004-2)	15	-	-

* Specimens oriented in the major rolling direction.
** Specimens oriented normal to the major rolling direction.
*** Heat of weld wire and lot of flux used is identical to that used for longitudinal seams in the intermediate and lower shells and associated girth seam (which joins the two shells).

The following dosimeters are included in each of the six capsules:

1. Iron,
2. Copper,
3. Nickel,
4. Cobalt-Aluminum (0.15 percent Co),
5. Cobalt-Aluminum (Cadmium shielded),
6. U-238 (Cadmium shielded), and
7. Np-237 (Cadmium shielded).

The following thermal monitors are included in each of the six capsules:

1. 97.5 percent Pb, 2.5 percent Ag (579°F melting point).
2. 97.5 percent Pb, 1.75 percent Ag, 0.75 percent Sn (590°F melting point).

The fast neutron exposure of the specimens occurs at a faster rate than that experienced by the vessel wall, with the specimens being located between the core and the vessel. Since these specimens experience accelerated exposure and are actual samples from the materials used in the vessel, the transition temperature shift measurements are representative of the vessel at a later time in life. Data from CT fracture toughness specimens are expected to provide additional information for use in determining allowable stresses for irradiated material.

Correlations between the calculations and the measurements of the irradiated samples in the capsules, assuming the same neutron spectrum at the samples and the vessel inner wall, are described in

Section 5.3.1.6.1. They have indicated good agreement. The calculations of the integrated flux at the vessel wall are conservative. The anticipated degree to which the specimens will perturb the fast neutron flux and energy distribution will be considered in the evaluation of the surveillance specimen data. Verification and possible readjustment of the calculated wall exposure will be made by use of data on all capsules withdrawn. The reactor vessel material irradiation surveillance capsules are removed and examined, to determine changes in material properties, at the intervals shown in Table 5.3-6. The heatup and cooldown limit curves for normal operation are developed from these examinations and are provided in the Licensing Requirements Manual. The schedule for removal of the capsules for postirradiation testing conforms with Appendix H of 10 CFR 50.

5.3.1.6.1 Measurement of Integrated Fast Neutron (E > 1.0 MeV) Flux at the Irradiation Samples

In order to effect a correlation between fast neutron (E > 1.0 MeV) exposure and the radiation induced property changes observed in the test specimens, a number of fast neutron flux monitors are included as an integral part of the Reactor Vessel Surveillance Program. In particular, the surveillance capsules contain detectors employing the following reactions:

1. Fe-54 (n,P) Mn-54,
2. Ni-58 (n,P) Co-58,
3. CU-63 (n,α) Co-60,
4. Np-237 (n,f) Cs-137, and
5. U-238 (n,f) Cs-137.

In addition, thermal neutron flux monitors, in the form of bare and cadmium shielded Co-Al wire, are included within the capsules to enable an assessment of the effects of isotopic burnup on the response of the fast neutron detectors.

The use of activation detectors such as those listed previously does not yield a direct measure of the energy dependent neutron flux level at the point of interest. Rather, the activation process is a measure of the integrated effect that the time and energy dependent neutron flux has on the target material. An accurate estimate of the average neutron flux level incident on the various detectors may be derived from the activation measurements only if the parameters of the irradiation are well known. In particular, the following variables are of interest:

1. The operating history of the reactor,
2. The energy response of the given detector, and
3. The neutron energy spectrum at the detector location.

The procedure for the derivation of the fast neutron flux from the results of the Fe-54 (n,P) Mn-54 reaction is described as follows. The measurement technique for the other dosimeters, which are sensitive to different portions of the neutron energy spectrum, is similar.

The Mn-54 product of the Fe-54 (n,P) Mn-54 reaction has a half-life of 314 days and emits gamma rays of 0.84 MeV energy which are easily detected using a gamma spectrometer. Typically a Ge (Li) or Ge spectrometer is used which has high resolution enabling an accurate value to be determined for the Mn-54 activity even if other activities are present.

The analysis of the sample requires that two procedures be completed. First, the Mn-54 disintegration rate per unit mass of sample and the iron content of the sample must be measured as described above. Second, the neutron energy spectrum at the detector location must be calculated.

For this analysis, a two-dimensional, multigroup, discrete ordinates transport code (DOT) (Soltesz, 1970) is employed to calculate the spectral data at the location of interest. The DOT calculations utilize a group energy scheme and a P_3 expansion of the scattering cross-sections to compute neutron radiation levels within the geometry of interest. The cross sections used in the analyses are obtained from the SAILOR cross section library (Sailor) which was developed specifically for light water reactor applications. The reactor geometry employed here includes a description of the radial regions internal to the primary concrete (core barrel, neutron pad, pressure, and water annuli) as well as the surveillance capsule and an appropriate reactor core fuel loading pattern and power distribution. Thus, distortions in the fission spectrum due to the attenuation of the reactor internals are accounted for in the analytical approach.

Having the measured activity, sample weight, and neutron energy spectrum at the location of interest, the calculation of the threshold flux is as follows:

The induced Mn-54 activity in the iron flux monitors may be expressed as:

$$D = \frac{N_o}{A} f_i \int_E \sigma(E)\phi(E) \sum_{J=1}^{n} F_J (1 - e^{-\lambda\tau} J) e^{-\lambda\ \ \tau} d \tag{5.3-1}$$

where:

D	=	Induced Mn-54 activity	(dps/gmFe)
N_o	=	Avogadro's number	(atoms/gm-atom)
A	=	Atomic weight of iron	(gm/gm-atom)
f_i	=	Weight fraction of Fe-54 in the detector	
$\sigma(E)$	=	Energy dependent activation cross-section for the Fe-54(n,P) Mn-54 reaction	(barns)
$\phi(E)$	=	Energy dependent neutron flux at the detector at full reactor power	(n/cm^2-sec)
λ	=	Decay constant of Mn-54	(l/sec)
F_J	=	Fraction of full reactor Power during the Jth time Interval, τ_J	
τ_J	=	Length of Jth irradiation Period	(sec)
τ_d	=	Decay time following the Jth irradiation period	(sec)

The parameters F_J, τ_J, and τ_d depend on the operating history of the reactor and the delay between capsule removal sample counting.

The integral term in Equation 5.3-1 may be replaced by the following relation:

$$\int \sigma(E)\phi(E) = \bar{\sigma}\,\bar{\phi}_{E_{TH}} = \left[\frac{\sum\limits_{o}^{\infty} \sigma_s(E)\phi_s(E)}{\sum\limits_{E_{TH}}^{\infty} \phi_s(E)}\right] \bar{\phi}_{E_{TH}} \qquad (5.3\text{-}2)$$

where:

$\bar{\sigma}$	=	Effective spectrum average reaction cross-section for neutrons above energy, E_{TH}

$\phi_{E_{TH}}$ = Average neutron flux above energy, E_{TH}

$\sigma_S(E)$ = Multigroup Fe-54 (n,P) Mn-54 reaction cross sections compatible with the DOT energy group structure

$\phi_S(E)$ = Multigroup energy spectra at the Detector location obtained from the DOT analysis

Thus,

$$D = \frac{N_o}{A} f_i \, \overline{\sigma} \; \overline{\phi}_{E_{TH}} \sum_{J=1}^{n} F_J (1 - e^{-\lambda\tau} J) \, e^{-\lambda \quad \tau} d$$

(5.3-3)

or, solving for the threshold flux:

$$\overline{\phi}_{E_{TH}} = \frac{D}{\frac{N_o}{A} f_i \; \overline{\sigma} \sum_{J=1}^{n} F_J \; (1 - e^{-\lambda\tau} J) \; e^{-\lambda \quad \tau} d}$$

(5.3-4)

The total fluence above energy E_{TH} is then given by:

$$\phi_{E_{TH}} = \overline{\phi}_{E_{TH}} \sum_{J=1}^{n} F_J \tau_J$$

(5.3-5)

where:

$\sum_{J=1}^{n} F_J \tau_J$ represents the total effective full power seconds of reactor operation up to the time of capsule removal.

Because of the relatively long half-life of Mn-54, the fluence may be accurately calculated in this manner for irradiation periods up to about two years. Beyond this time, the calculated average flux begins to be weighted toward the later stages of irradiation and some

inaccuracies may be introduced. At these longer irradiation times, more reliance must be placed on Np-237 and U-238 fission detectors with their 30-year half-life product (Cs-137).

No burnup correction to the measured activities is necessary since burnout of the Mn-54 product is not significant until the thermal flux level is about 10^{14}n/cm^2-sec.

The error involved in the measurement of the specific activity of the detector after irradiation is estimated to be ±5 percent.

5.3.1.6.2 Calculation of Integrated Fast Neutron (E>l.0MeV) Flux at the Irradiation Samples

The energy and spatial distribution of neutron flux within the reactor geometry is obtained from the DOT (Soltesz 1970) two-dimensional Sn transport code. The radial and azimuthal distributions are obtained from an R, θ computation wherein the reactor core as well as the water and steel annuli surrounding the core are modeled explicitly. The axial variations are then obtained from an R,Z, DOT calculation using the equivalent cylindrical core concept. The neutron flux at any point in the geometry is then given by:

$$\phi(E,R,\theta,Z) = \phi(E,R,\theta)\,F(Z) \tag{5.3-6}$$

Where $\phi(E,R,\theta)$ is obtained directly from the R,θ calculation and F(Z) is a normalized function obtained from the R,Z analysis. Core power distributions representative of time-averaged conditions derived from statistical studies of long-term operation of Westinghouse three-loop plants are employed. These input distributions, which are characteristic of out-in fuel loading patterns (fresh fuel on the periphery), include rod-by-rod spatial variations for all peripheral fuel assemblies.

Benchmark testing of these generic or design basis power distributions against surveillance capsule data from two-loop, three-1oop, and four-loop Westinghouse plants indicates that this analytical approach yields conservative results, with calculations exceeding measurements from 10 to 20 percent (Benchmark Testing of Westinghouse Neutron Transport Analysis Methodology).

Having the calculated neutron flux distributions within the reactor geometry, the exposure of the capsule as well as the lead factor between the capsule and the vessel may be determined as follows:

The neutron flux at the surveillance capsule is given by:

$$\phi_C = \phi(E, R_C, q_C, Z_C) \tag{5.3-7}$$

and the flux at the location of peak exposure on the pressure vessel inner diameter is:

$$\phi_{v-max} = \phi(E, R_v, q_{v-max}, Z_{v-max}) \tag{5.3-8}$$

The lead factor then becomes:

$$LF = \frac{\phi_c}{\phi_{v-\max}} \tag{5.3-9}$$

Similar expressions may be developed for points within the pressure vessel wall, and thus, together with the surveillance program dosimetry, serve to correlate the radiation induced damage to test specimens with that of the reactor vessel.

One must realize that the lead factors are sensitive to core power distribution. For example, low leakage fuel management may reduce neutron leakage by differing amounts along the periphery of the core. An altered azimuthal distribution of fast neutron flux, compared to the design basis shape, may change the relationship between the flux at a capsule and the peak flux on the vessel. It is prudent to examine the impact of changing core power distributions on lead factors and adjust surveillance capsule withdrawal schedules when necessary.

5.3.1.7 Reactor Vessel Fasteners

The reactor vessel closure studs, nuts, and washers are designed and fabricated in accordance with the requirements of the ASME Code, Section III. The closure studs are fabricated of SA 540, Class 3, Grade B24 or equivalent. The closure stud material meets the fracture toughness requirements of the ASME Code, Section III and 10 CFR 50, Appendix G. Bolting materials fracture toughness data are given in Table 5.3-2. Compliance with Regulatory Guide 1.65, Materials and Inspections for Reactor Vessel Closure Studs, is discussed in Section 1.8.

Nondestructive examinations are performed in accordance with the ASME Code, Section III.

Refueling procedures require removable studs, nuts, and washers to be removed from the reactor closure and be placed in storage racks during preparation for refueling. The storage racks are then removed from the refueling cavity and stored at convenient locations on the containment operating deck prior to removal of the reactor closure head and refueling cavity flooding. Closure studs numbers 25, 37, and 51 are not removable. It has been determined that exposure to borated water for these studs will not cause degradation of their function. Protection against the possibility of incurring significant corrosion effects is assured by the use of manganese base phosphate surfacing treatment.

The stud holes in the reactor flange are sealed with special plugs before removing the reactor closure, thus preventing leakage of the borated refueling water into the stud holes.

5.3.2 Pressure - Temperature Limits

5.3.2.1 Limit Curves

Start-up and shutdown operating limitations will be based on the properties of the core region materials of the reactor pressure vessel (Hazelton 1975). Actual material property test data will be used. The methods outlined in Appendix G of the ASME Code, Section III will be employed for the shell regions in the analysis of protection against nonductile failure. The initial operating curves are calculated assuming a period of reactor operation such that the beltline material will be limiting. The heatup and cooldown curves are given in the Licensing Requirements Manual. Beltline material properties degrade with radiation exposure, and this degradation is measured in terms of the adjusted reference nil-ductility temperature which includes a reference nil-ductility temperature shift (ΔRT_{NDT}).

Predicted ΔRT_{NDT} values are derived using two curves: the effect of fluence and copper content on the shift of ΔRT_{NDT} for the reactor vessel steels exposed to 550°F temperature curve, and the maximum fluence of 1/4 T and 3/4 T locations (tips of the code reference flaw when the flaw is assumed at inside diameter and outside diameter locations, respectively) curve. These curves are presented in the Licensing Requirements Manual. For a selected time of operation, this shift is assigned a sufficient magnitude so that no unirradiated ferritic materials in other components of the reactor coolant system (RCS) will be limiting in the analysis.

The operating curves, including pressure-temperature limitations, are calculated in accordance with 10 CFR 50, Appendix G and ASME Code, Section III, Appendix G requirements. Changes in fracture toughness of the core region plates, weldments, and associated heat affected zones due to radiation damage will be monitored by a surveillance program which conforms with 10 CFR 50, Appendix H. The evaluation of the radiation damage in this surveillance program is based on pre-irradiation testing of Charpy V-notch and tensile specimens and post-irradiation testing of Charpy V-notch, tensile, and 1/2 T compact tension specimens. The post irradiation testing will be carried out during the lifetime of the reactor vessel. Specimens are irradiated in capsules located near the core mid-height and removable from the vessel at specified intervals.

The results of the radiation surveillance program will be used to verify that the ΔRT_{NDT} predicted from the effects of the fluence and copper content curve is appropriate and to make any changes necessary to correct the fluence and copper curves if ΔRT_{NDT} determined from the surveillance program is greater than the predicted ΔRT_{NDT}. Temperature limits for preservice hydrotests and inservice leak and hydrotests will be calculated in accordance with 10 CFR 50, Appendix G.

Compliance with Regulatory Guide 1.99, Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials, is discussed in Section 1.8.

5.3.2.2 Operating Procedures

The transient conditions that are considered in the design of the reactor vessel are presented in Section 3.9N.1.1. These transients are representative of the operating conditions that should prudently be considered to occur during BVPS-2 operation. The transients selected form a conservative basis for evaluation of the RCS to ensure the integrity of the RCS equipment.

Those transients listed as upset condition transients are listed in Table 3.9N-1. None of these transients will result in pressure-temperature changes which exceed the heatup and cooldown limitations as described in Section 5.3.2.1 and in the Licensing Requirements Manual.

5.3.3 Reactor Vessel Integrity

5.3.3.1 Design

The reactor vessel is shown on Figure 5.3-1.

The reactor vessel is cylindrical with a welded hemispherical bottom head and a removable, bolted, flanged, and gasketed, hemispherical upper head. The reactor vessel flange and head are sealed by two hollow metallic O-rings. Seal leakage is detected by means of two leakoff connections: one between the inner and outer ring and one outside the outer O-ring. The vessel contains the core, core support structures, control rods, and other parts directly associated with the core. The reactor vessel closure head contains head adaptors. These head adaptors are tubular members, attached by partial penetration welds to the underside of the closure head. The upper end of these adaptors contains acme threads for the assembly of CRDM or instrumentation adaptors. The seal arrangement at the upper end of these adaptors consists of a welded flexible canopy seal. Inlet and outlet nozzles are located symmetrically around the vessel. Outlet nozzles are arranged on the vessel to facilitate optimum layout of the RCS equipment. The inlet nozzles are tapered from the coolant loop vessel interfaces to the vessel inside wall to reduce loop pressure drop.

During refueling outages, inspections of the underside of the reactor vessel head are conducted to identify flaws in penetration tubes and associated welds in accordance with the requirements of 10CFR50.55a and ASME Code Case N-729-4.

Cracks have been identified at penetration locations 16, 51, 56 and 61. Weld repairs were conducted on the penetration tube outside diameter and J-groove welds of these penetrations as required. The method used for repairing the cracks is the embedded flaw technique submitted by relief request BV3-RV-04 and approved by an NRC safety evaluation dated May 14, 2003. Alloy 52 or 52M was applied on the applicable surfaces of the penetration tube to embed the flaw and prevent propagation of the crack.

Additional indications were identified at penetration locations 49 and 57. Weld repairs were conducted on the penetration tube outside diameter and J-groove welds of these penetrations as required. The method used for repairing the cracks is the embedded flaw technique submitted by relief request 2-TYP-3-RV-01 and approved by an NRC safety evaluation dated October 6, 2009. Alloy 52M was applied on the applicable surfaces of the penetration tube to embed the flaw and prevent propagation of the crack.

An indication was identified at penetration locations 41 and 44. Weld repairs were conducted on the penetration tube outside diameter and J-groove welds of these penetrations as required. The method used for repairing the cracks is the embedded flaw technique submitted by relief request 2-TYP-3-RV-03, as supplemented, and approved by an NRC safety evaluation dated February 25, 2011. Alloy 52M was applied on the applicable surfaces of the penetration tube to embed the flaw and prevent propagation of the crack. Alternatives to the non-destructive examination acceptance criteria and the filler metal to be used for the part of the repair overlay that extends beyond the J-groove weld and over the stainless steel clad on the inside surface of the reactor vessel head were employed, as proposed in the supplement to relief request 2-TYP-3-RV-03.

An indication was identified at penetration location 27. A weld repair was conducted on the penetration tube outside diameter and the J-groove welds of this penetration as required. The method used for repairing the crack was the embedded flaw technique submitted by relief request 2-TYP-4-RV-04 and approved by an NRC safety evaluation dated August 27, 2018. Alloy 52M was applied on the applicable surfaces of the penetration tube and the j-groove weld to embed the flaw and prevent propagation of the crack.

The repair activities removed a portion of the thermal sleeve and the associated guide funnel at penetrations 16, 41, 44, 56, 57 and 61 to allow access for the welding equipment used to repair the head at this location. A thermal sleeve remnant was left in penetration 16 after the repair. For penetrations 41, 44, 56, 57 and 61, a new thermal sleeve was re-installed after the repair. Thermal sleeves do not have a required function for protection from thermal transients as the name implies. The design function of the thermal sleeve is to provide guidance for the control rod driverods. The function of the thermal sleeve funnel is to provide guidance of the driverods into the thermal sleeve as the head is lowered onto the vessel. Penetration 16 does not contain a CRDM. Additionally, at penetrations 49 and 51 a thermocouple housing guide was permanently removed to facilitate the repair. The housing guide assists in reactor reassembly; however, reactor reassembly can be performed without it. The housing guide is not required for reactor operation.

The bottom head of the vessel contains penetration nozzles for connection and entry of the nuclear incore instrumentation. Each nozzle consists of a tubular member made of an Inconel tube. Each tube is attached to the inside of the bottom head by a partial penetration weld.

Internal surfaces of the vessel which are in contact with primary coolant are weld overlay with 0.125-inch minimum of stainless steel or Inconel. The exterior of the reactor vessel is insulated with canned stainless steel reflective sheets, or canned borated fiberglass. The reflective insulation is a minimum of three inches thick, and the fiberglass insulation is a minimum of one inch thick. Provisions are made for the removability of the insulation covering the closure and bottom heads to allow access for inservice inspection; access to the vessel side insulation is limited by the neutron shield tank.

The reactor vessel is designed and fabricated in accordance with the requirements of the ASME Code, Section III.

Principal design parameters of the reactor vessel are given in Table 5.3-4. The reactor vessel is shown on Figure 5.3-1.

There are no special design features which would prohibit the in-situ annealing of the vessel. If the unlikely need for an annealing operation was required to restore the properties of the vessel material opposite the reactor core because of neutron irradiation damage, a metal temperature greater than 650°F for a period of 168 hours maximum would be applied. Various modes of heating may be used depending on the temperature.

The reactor vessel materials surveillance program is adequate to accommodate the annealing of the reactor vessel. Sufficient specimens are available to evaluate the effects of annealing treatment.

Cyclic loads are introduced by normal power changes, reactor trip, start-up, and shutdown operations. These design base cycles are selected for fatigue evaluation and constitute a conservative design envelope for the projected plant life. Vessel analysis results in a usage factor that is less than 1.

The design specifications require analysis to prove that the vessel is in compliance with the fatigue and stress limits of the ASME Code, Section III. The loadings and transients specified for the analysis are based on the most severe conditions expected during service. Maximum heatup and cooldown rates imposed by BVPS-2 operating limits are defined in the Licensing Requirements Manual. The rate of 100°F per hour is reflected in the vessel design specifications as a normal condition for conservatism.

5.3.3.2 Materials of Construction

The materials used in the fabrication of the reactor vessel are discussed in Section 5.2.3.

5.3.3.3 Fabrication Methods

The BVPS-2 reactor vessel manufacturer is Combustion Engineering Corporation.

The BVPS-2 reactor vessel manufacturer is Combustion Engineering Corporation. Combustion Engineering Corporation is the largest reactor vessel fabricator in the United States, and their experience is demonstrated by the fact that they have fabricated over 40 reactor vessels for Westinghouse designed NSSSs, as well as additional vessels for other reactor vendors.

The fabrication methods used in the construction of the reactor vessel are described in Section 5.3.1.2.

5.3.3.4 Inspection Requirements

The nondestructive examinations performed on the reactor vessel are described in Section 5.3.1.3. Section 5.3.3.7 describes provisions for inservice inspection.

5.3.3.5 Shipment and Installation

The reactor vessel is shipped in a horizontal position on a shipping sled with a vessel lifting truss assembly. All vessel openings are sealed to prevent the entrance of moisture and an adequate quantity of desiccant bags is placed inside the vessel. These are usually placed in a wire mesh basket attached to the vessel cover. All carbon steel surfaces are painted with a heat-resistant paint before shipment except for the vessel support surfaces and the top surfaces of the external seal ring, which are coated with a petroleum based preservative.

The closure head is also shipped with a shipping cover and skid. An enclosure attached to the ventilation shroud support ring protects the control rod mechanism housing. All head openings are sealed to prevent the entrance of moisture, and an adequate quantity of desiccant bags are placed inside the head. These are placed in a wire mesh basket attached to the head cover. All carbon steel surfaces are painted with heat-resistant paint before shipment. A lifting frame is provided for handling the vessel head.

5.3.3.6 Operating Conditions

Operating limitations for the reactor vessel are discussed in Section 5.3.2 and presented in the Licensing Requirements Manual.

In addition to the analysis of the primary components discussed in Section 3.9N.1.4, the reactor vessel is further qualified to ensure against unstable crack growth under faulted conditions by performing detailed fracture analyses of the critical areas of this component. Actuation of the emergency core cooling system (ECCS) following a loss-of-coolant accident (LOCA) produces relatively high thermal stresses in regions of the reactor vessel which come into contact with ECCS water. Primary consideration is given to these areas, including the reactor vessel beltline region and the reactor vessel

primary coolant nozzle, to ensure the integrity of the reactor vessel under this severe postulated transient.

For the beltline region, significant developments have recently occurred in order to address Pressurized Thermal Shock (PTS) events. On the basis of recent deterministic and probabilistic studies, taking U.S. PWR operating experience into account, the NRC staff concluded that conservatively calculated screening criterion values of RTndt less than 270 degrees for plate material and axial welds, and less than 300 degrees for circumferential welds, present an acceptably low risk of vessel failure from PTS events. These values were chosen as the screening criterion in the PTS Rule for 10CFR50.34 (new plants) and 10CFR50.61 (operating plants) (Federal Register Vol. 50, No. 141, July 1985). The conservative methods chosen by the NRC Staff for the calculation of RTpts for the purpose of comparison with the screening criterion is presented in paragraph (b) (2) of 10CFR50.61. Details of the analysis method and the basis for the PTS Rule can be found in SECY-82-465. (SECY-81-465, November 1982).

The reactor vessel beltline materials are specified in Section 5.3.1. The fluence of 6.5 x 10^{19} N/cm^2, which is the design basis fluence at the vessel inner radius, at 32 EFPY, at the peak location, was used for calculating all of the RTpts values. RTpts is RTndt, the reference nil-ductility transition temperature as calculated by the method chosen by the NRC Staff as presented in paragraph (b) (2) of 10CFR50.61, and the "PTS Rule." The PTS Rule states that this method of calculating RTpts should be used in reporting values used to be compared to the above Screening Criterion set in the PTS Rule. The screening criteria will not be exceeded using the method of calculation prescribed by the PTS Rule for the vessel design lifetime. The material properties, initial RTndt, and end-of-life RTpts values are in Table 5.3-5. The materials identified in Table 5.3-5 are those materials that are exposed to high fluence levels at the beltline region of the reactor vessel and are, therefore, the subject of the PTS Rule. These materials, therefore, are a subset of the materials identified in Section 5.3.1.

The principles and procedures of linear elastic fracture mechanics (LEFM) are used to evaluate thermal effects in the regions of interest. The LEFM approach to the design against failure is basically a stress intensity consideration in which criteria are established for fracture instability in the presence of a crack. Consequently, a basic assumption employed in LEFM is that a crack or

crack-like defect exists in the structure. The essence of the approach is to relate the stress field developed in the vicinity of the crack tip to the applied stress on the structure, the material properties, and the size of defect necessary to cause failure.

The elastic stress field at the crack-tip in any cracked body can be described by a single parameter, designated as the stress intensity factor, K. The magnitude of the stress intensity factor K is a function of the geometry of the body containing the crack, the size and location of the crack, and the magnitude and distribution of the stress.

The criterion for failure in the presence of a crack is that failure will occur whenever the stress intensity factor exceeds some critical value. For the opening mode of loading (stresses perpendicular to the major plane of the crack), the stress intensity factor is designated as K_I and the critical stress intensity factor is designated K_{IC}. Commonly called the fracture toughness, K_{IC} is an inherent material property which is a function of temperature and strain rate. Any combination of applied load, structural configurate, crack geometry, and size which yields a stress intensity factor K_{IC} for the material will result in crack instability.

The criterion of the applicability of LEFM is based on plasticity considerations at the postulated crack tip. Strict applicability (as defined by ASTM) of LEFM to large structures where plane strain conditions prevail, requires that the plastic zone developed at the tip of the crack does not exceed 2.25 percent of the crack depth. In the present analysis, the plastic zone at the tip of the postulated crack can reach 20 percent of the crack depth. However, LEFM has been successfully used to provide conservative brittle fracture prevention evaluations, even in cases where strict applicability of the theory is not permitted due to excessive plasticity. Recently, experimental results from the Electric Power Research Institute sponsored Heavy Steel Section Technology (HSST) Program intermediate pressure vessel tests have shown that LEFM can be applied conservatively as long as the pressure component of the stress does not exceed the yield strength of the material. The addition of the thermal stresses, calculated elastically, which result in total stresses in excess of the yield strength, does not affect the conservatism of the results provided that these thermal stresses are included in the evaluation of the stress intensity factors. Therefore, for faulted conditions analyses, LEFM is considered applicable for the evaluation of the vessel inlet nozzle and beltline region.

In addition, it has been well established that the crack propagation of existing flaws in a structure subjected to cyclic loading can be defined in terms of fracture mechanics parameters. Thus, the principles of LEFM are also applicable to fatigue growth of a postulated flaw at the vessel inlet nozzle and beltline region.

An example of a faulted condition evaluation carried out according to the procedure discussed above is given by Buchalet and Mager (1973). This report discusses the evaluation procedure in detail as applied to a severe faulted condition (a postulated LOCA) and concludes that the integrity of the reactor coolant pressure boundary would be maintained in the event of such an accident.

5.3.3.7 Inservice Surveillance

The internal surface of the reactor vessel is capable of inspection periodically using visual and/or nondestructive techniques over the accessible areas. During refueling, the vessel cladding is capable of being inspected in certain areas between the closure flange and the primary coolant inlet nozzles. If deemed necessary, the core barrel is capable of being removed, making the entire inside vessel surface accessible.

The closure head is capable of being examined visually during each refueling. The reactor vessel head could present problems because of radiation levels. Optical devices may be used which permit a selective inspection of the cladding, CRDM nozzles, and the gasket seating surface. The knuckle transition piece, which is the area of highest stress of the closure head, is accessible to the outer surface for visual inspection, dye penetrant, magnetic particle, and/or ultrasonic testing. Removable closure studs can be inspected periodically using visual, magnetic particle, and/or ultrasonic techniques. Per ASME Section XI, Table IWB-2500-1, a volumetric examination is all that is required for studs that remain in place.

The closure studs, nuts, washers, and the vessel flange seal surface, as well as the full penetration welds in the following areas of the installed reactor vessel are available for nondestructive examination:

1. Vessel shell - from the inside surface.

2. Primary coolant nozzles - from the inside surface.

3. Closure head - from the inside and outside surfaces. Bottom head - from the outside surface.

4. Field welds between the reactor vessel nozzle safe ends and the main coolant piping.

The design considerations which have been incorporated into the system design to permit the above inspections are as follows:

1. All reactor internals are completely removable. The tools and storage space required to permit these inspections are provided.

2. The closure head is stored dry in the reactor head storage area which is located on a deck at the bottom of the

containment during refueling to facilitate direct visual inspection.

3. All removable reactor vessel studs, nuts, and washers can be removed to dry storage during refueling.

The reactor vessel presents access problems because of the radiation levels and remote underwater accessibility to this component. Because of the limitations on access to the reactor vessel, several steps have been incorporated into the design and manufacturing procedures in preparation for the periodic inservice inspections which are required by ASME Section XI. These are:

1. Shop ultrasonic examinations are performed on all internally clad surfaces to assure an adequate cladding bond to allow later ultrasonic testing of the base metal from inside surface. The maximum allowable size of clad bonding defect allowed is 1/4 inch by 3/4 inch with the greater direction parallel to the weld in the region bounded by 2T (T = wall thickness) on both sides of each full penetration pressure boundary weld. Unbounded areas exceeding 0.442 square inches (3/4 -inch diameter) in all other regions are rejected.

2. The design of the reactor vessel shell is an uncluttered cylindrical surface to permit future positioning of the test equipment without obstruction.

3. The weld deposited clad surface on both sides of the welds to be inspected are specifically prepared to assure meaningful ultrasonic examinations.

4. During fabrication, all full penetration ferritic pressure boundary welds are ultrasonically examined in addition to ASME code examinations.

5. After the shop hydrostatic testing, all full penetration ferritic pressure boundary welds, as well as the nozzle to safe end welds, are ultrasonically examined in addition to ASME Code, Section III requirements.

The vessel design and construction permit inspection is in accordance with the ASME Code, Section XI.

5.3.4 References for Section 5.3

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Tables for Section 5.3

TABLE 5.3-1

UNIRRADIATED FRACTURE TOUGHNESS PROPERTIES OF THE REACTOR VESSEL

Component	Code No.	Mat'l Spec. No.	Cu %	Ni %	P %	T_{NDT} °F	50 Ft-Lb 35 Mil Temp. °F	RT_{NDT} °F	USE Ft-Lbs
Closure head dome	B9008-1	A533B CL. 1	0.13	0.51	0.013	-20	50	-10	137
Closure head flange	B9002-1	A508 CL. 2	-	0.94	0.012	-10	<40	-10	136
Vessel flange	B9001-1	A508 CL. 2	-	0.93	0.010	0	<10	0	132.5
Inlet nozzle	B9011-1	A508 CL. 2	-	0.88	0.006	0	<10	0	104
Inlet nozzle	B9011-2	A508 CL. 2	-	0.88	0.010	10	<10	10	115
Inlet nozzle	B9011-3	A508 CL. 2	-	0.84	0.009	20	<40	20	122
Outlet nozzle	B9012-1	A508 CL. 2	-	0.71	0.007	-10	<0	-10	137
Outlet nozzle	B9012-2	A508 CL. 2	-	0.94	0.006	-10	<0	-10	121
Outlet nozzle	B9012-3	A508 CL. 2	-	0.68	0.008	-10	<0	-10	112
Nozzle shell	B9003-1	A533B CL. 1	0.13	0.61	0.008	-10	110	50	98
Nozzle shell	B9003-2	A533B CL. 1	0.12	0.58	0.009	0	120	60	79.5
Nozzle shell	B9003-3	A533B CL. 1	0.13	0.61	0.008	-10	110	50	97.5
Inter. shell	B9004-1	A533B CL. 1	0.07	0.53	0.010	0	120	60	83
Inter. shell	B9004-2	A533B CL. 1	0.07	0.59	0.007	-10	100	40	75.5
Lower shell	B9005-1	A533B CL. 1	0.08	0.59	0.009	-50	88	28	82
Lower shell	B9005-2	A533B CL. 1	0.07	0.58	0.009	-40	93	33	77.5
Bottom head torus	B9010-1	A533B CL. 1	0.15	0.49	0.007	-30	56	-4	97
Bottom head dome	B9009-1	A533B CL. 1	0.14	053	0.007	-30	35	-25	116
Weld (inter. & lower shell long seams & girth seam)*			0.08	0.87	.008	-30	<30	-30	144.5
HAZ (Plate B9004-2)			-	-	-	-80	40	-20	76

NOTE:

*Same heat of wire and lot of flux used in all seams including surveillance weldment.

TABLE 5.3-2

CLOSURE HEAD BOLTING MATERIAL PROPERTIES

Closure Head Studs

Head No.	Mat'l Spec No.	Bar No.	0.2% YS KSI	UTS KSI	Elong. %	RA %	BHN	Energy At 10°F Ft-Lb	Lateral Expansion Mils
80726	A540,B24	107	148.0	160.0	17.0	52.2	331	48,47,48	30,27,29
80726	A540,B24	107-1	147.5	160.0	17.0	52.5	341	47,49,50	28,27,29
81401	A540,B24	110	141.5	156.0	17.5	58.8	331	57,55,54	38,37,33
81401	A540,B24	110-1	140.0	155.0	18.0	59.8	341	51,55,54	30,33,33
81401	A540,B24	112	149.2	164.0	17.5	57.8	341	53,51,50	35,30,28
81401	A540,B24	112-1	143.5	159.0	17.5	57.5	341	54,54,51	33,33,38
81401	A540,B24	121	145.0	158.5	18.5	59.4	341	54,54,54	33,35,34
81401	A540,B24	121-1	145.0	159.0	18.0	58.1	331	55,57,54	36,38,32
				Closure Head Nuts & Washers					
18947	A540,B23	55	147.7	161.0	17.0	54.7	341	50,50,51	31,32,31
18947	A540,B23	55-1	152.0	164.5	17.0	55.7	341	50,49,52	30,30,33
18947	A540,B23	60	152.2	164.5	16.5	54.7	341	48,47,47	28,26,28
18947	A540,B23	60-1	151.7	164.0	16.0	53.0	352	47,46,48	31,28,30

TABLE 5.3-3

REACTOR VESSEL QUALITY ASSURANCE PROGRAM

Components	RT*	UT**	PT***	MT****
Forgings				
Flanges		yes		yes
Studs, nuts		yes		yes
CRD head adaptor flange		yes	yes	
CRD head adaptor tube		yes	yes	
Instrumentation tube		yes	yes	
Main nozzles		yes		yes
Nozzle safe ends		yes	yes	
Plates		yes		yes
Weldments				
Main seam	yes	yes		yes
CRD head adaptor to closure head connection			yes	
Instrumentation tube to bottom head connection			yes	
Main nozzle	yes	yes		yes
Cladding		yes	yes	
Nozzle to safe ends	yes	yes	yes	
Nozzle to safe ends after hydrotest		yes	yes	
CRD head adaptor flange to CRD head adaptor tube	yes		yes	
All full penetration ferritic pressure boundary welds accessible after hydrotest		yes		yes
Seal ledge				yes
Head lift Lugs				yes
Core pad welds			yes	

NOTES:

*RT - Radiographic.
**UT - Ultrasonic.
***PT - Dye penetrant.
****MT - Magnetic particle.

TABLE 5.3-4

REACTOR VESSEL DESIGN PARAMETERS

Component	Design Parameters
Design/operating pressure (psig)	2485/2235
Design temperature (°F)	650
Overall height of vessel and closure head (bottom head outside diameter to top of control rod mechanism adapter) (ft-in)	42-7 3/16
Thickness of insulation, minimum (in)	
Stainless steel reflective	3
Canned fiberglass	1
Number of reactor closure head studs	58
Diameter of reactor closure head studs, minimum shank (in)	6
Inside diameter of flange (in)	149-9/16
Outside diameter of flange (in)	184
Inside diameter at shell (in)	157
Inlet nozzle inside diameter (in)	27-1/2
Outlet nozzle inside diameter (in)	29
Clad thickness, minimum (in)	1/8
Lower head thickness, minimum (in)	5
Vessel belt-line thickness, minimum (in)	7-7/8
Closure head thickness (in)	6-3/16

TABLE 5.3-5

REACTOR VESSEL VALUES FOR
ANALYSIS OF POTENTIAL PRESSURIZED
THERMAL SHOCK EVENTS 10CFR50.34

MATERIAL		CU%	NI%	INITIAL RT NDT	END OF LIFE RT PTS
Intermediate Shell	B9004-1	.07	.53	60	149
	2	.07	.59	40	124
Lower Shell	B9005-1	.08	.59	28	131
	2	.07	.58	33	126
Weld (Intermediate Lower shell long seams and girth seams)		.08	.09	-30	63

TABLE 5.3-6

REACTOR VESSEL MATERIAL IRRADIATION SURVEILLANCE SCHEDULE

Capsule	Current (Original) Capsule Location	Lead Factor[(a)]	Withdrawal EFPY[(b)]	Fluence, f[(a)] [n/cm^2, E > 1.0 MeV]
U	343^o	3.17	1.25	6.15 x 10^{18}
V	107^o	3.64	5.99	2.64 x 10^{19}
W	110^o	3.25	9.84	3.61 x 10^{19}
X	287^o	3.69	14.00	5.63 x 10^{19}
Y[(c)]	290^o	3.17	(c)	---
Z[(c)]	340^o	3.17	(c)	---
A[(d)]	107^o	3.58	32[(d)]	---

a) Updated in WCAP-16527-NP, Supplement 1, Revision 1.

b) Effective full power years (EFPY) from plant startup. Changes to this column will require prior NRC approval (except to indicate that capsules have been removed), as specified in Section III.B.3, Appendix H of 10 CFR 50.

c) It is recommended that one of these capsules be pulled at a time when the capsule fluence exceeds one times the projected peak 80-year EOL fluence, but before the capsule fluence reaches two times the projected 60-year EOL fluence. Therefore, based on the current information, Capsule Y or Z should be withdrawn between 20.5 EFPY and 32.4 EFPY. In order to be consistent with NUREG-1929, “Safety Evaluation Report Related to the License Renewal of Beaver Valley Power Station, Units 1 and 2,” this capsule should be pulled at the refueling outage closest to 26.1 EFPY, which corresponds with a peak vessel fluence level of 8.5 x 10^{19} *n/cm*^{2} (E > 1.0 MeV). The second capsule will remain in the vessel to provide fluence monitoring or future testing. The withdrawal of this capsule will be revisited at a later time.

d) Supplemental Capsule A contains BVPS-1 initially unirradiated material specimens, as well as previously irradiated material specimens from BVPS-1, St. Lucie, and Fort Calhoun. Supplemental Capsule A was inserted in the vacant Capsule V location at the end of Cycle 8. In order to be consistent with the “Materials Reliability Program: Coordinated PWR Reactor Vessel Surveillance Program (CRVSP) Guidelines (MRP-326)” recommendation, Capsule A is to be removed and tested when it reaches a fluence value equivalent to the peak 80-year vessel fluence for BVPS-1. This is expected to occur at approximately 32 EFPY.

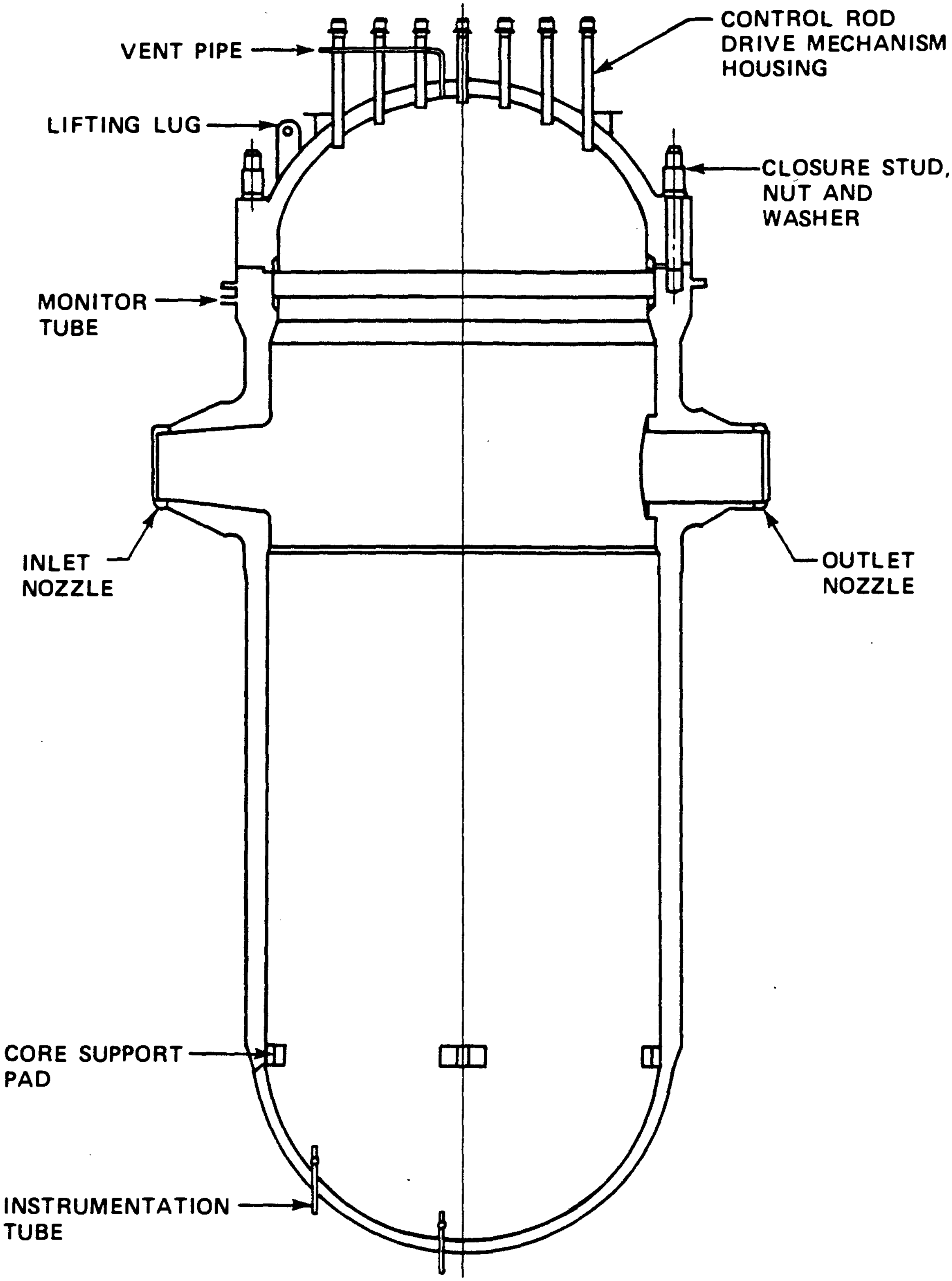

FIGURE 5.3-1
REACTOR VESSEL
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

5.4 COMPONENT AND SUBSYSTEM DESIGN

5.4.1 Reactor Coolant Pump

5.4.1.1 Design Bases

The reactor coolant pump (RCP) ensures an adequate core cooling flow rate for sufficient heat transfer to maintain a departure from nucleate boiling ratio greater than 1.30 within the parameters of operation. By conservative pump design, the required net positive suction head (NPSH) is always less than that available by system design and operation.

Sufficient pump rotation inertia is provided by a flywheel, in conjunction with the pump and rotor assembly, to provide adequate flow during coastdown. This forced flow following an assumed loss of pump power and the subsequent natural circulation effect provides the core with adequate cooling.

The RCP motor is tested, without mechanical damage, at overspeeds up to and including 125 percent of normal speed. The integrity of the flywheel during a loss-of-coolant accident (LOCA) is demonstrated in WCAP-8163 Report (Westinghouse 1973).

The RCP design parameters are given in Table 5.4-1.

Code and material requirements are provided in Section 5.2.

5.4.1.2 Pump Description

5.4.1.2.1 Design Description

The RCP is a vertical, single stage, controlled leakage, centrifugal pump designed to pump large volumes of main coolant at high temperatures and pressures.

The pump consists of three major areas. They are the hydraulics, the shaft seals, and the motor.

1. The hydraulic section consists of the casing, impeller, diffuser adapter, turning vane-diffuser, and heat exchanger assembly.

2. The shaft seal section consists of the number 1 controlled leakage, film riding face seal, number 2 and number 3 rubbing face seals, and a shutdown seal assembly (SDS). The seals are contained within the thermal barrier heat exchanger assembly and seal housing. The SDS is housed within the number 1 seal area and is a passive device actuated by high temperature resulting from a loss of seal injection and CCW cooling to the thermal barrier heat exchanger.

3. The motor is a drip-proof squirrel cage induction motor with a vertical solid shaft an oil lubricated double-acting

Kingsbury type thrust bearing, upper and lower oil lubricated radial guide bearings, and a flywheel.

Additional components of the pump are the shaft, pump radial bearing, coupling, spool piece, and motor stand.

5.4.1.2.2 Description of Operation

The reactor coolant enters the suction nozzle, is directed to the impeller by the diffuser adapter, is pumped through the turning vane-diffuser, and exits through the discharge nozzle.

Seal injection flow, under slightly higher pressure than the reactor coolant, enters the pump through a connection on the thermal barrier flange and is directed into the plenum between the thermal barrier housing and the shaft. The flow splits with a portion flowing down the shaft through the radial bearing and into the reactor coolant system (RCS); the remainder flows up the shaft through the seals.

Primary plant component cooling water (CCW) is provided to the pump heat exchanger. During normal operation, this heat exchanger limits the heat transfer from hot reactor coolant to the radial bearing and to the seals. In addition, if a loss of seal injection flow should occur, the heat exchanger cools the reactor coolant to an acceptable level before it enters the bearing and seal area.

The RCP motor bearings are of conventional design. The radial bearings are the segmented pad type, and the thrust bearing is a double-acting Kingsbury type. All the bearings are oil lubricated. Primary plant CCW is supplied to the external upper bearing oil cooler and to the integral lower bearing oil cooler.

The motor is a water and air cooled, Class B thermelastic epoxy insulated, squirrel cage induction motor. The rotor and stator are of standard construction and are cooled by air. Six resistance temperature detectors are imbedded in the stator windings to sense stator temperature. A flywheel and an anti-reverse rotation device are located at the top of the motor.

The internal parts of the motor are cooled by air. Integral vanes on each end of the rotor draw air in through cooling slots in the motor frame. This air passes through the motor with particular emphasis on the stator end turns. It is then routed to the external water/air heat exchangers, which are supplied with primary plant CCW. Each motor has two such coolers, mounted diametrically opposed to each other. In passing through the coolers, the air is cooled so that minimum heat is rejected to the containment from the motors.

All parts of the pump in contact with the reactor coolant are austenitic stainless steel except for seals, bearings, and special parts.

5.4.1.3 Design Evaluation

5.4.1.3.1 Pump Performance

The RCPs are sized to deliver flow at rates which equal or exceed the required flow rates. Preoperational RCS tests confirm the total delivery capability. Thus, assurance of adequate forced circulation coolant flow is provided prior to initial Beaver Valley Power Station-Unit 2 (BVPS-2) operation.

The estimated performance characteristic is shown on Figure 5.4-2. The knee, at about 45 percent design flow, introduces no operational restrictions, since the pumps operate at full flow.

The reactor trip system (RTS) ensures that pump operation is within the assumptions used for loss-of-coolant flow (LOCF) analyses, which also assures that adequate core cooling is provided to permit an orderly reduction in power if flow from an RCP is lost during operation.

An extensive test program has been conducted for several years to develop the controlled leakage shaft seal for pressurized water reactor (PWR) applications. Long term tests were conducted on less than full scale prototype seals as well as on full size seals. Operating plants continue to demonstrate the satisfactory performance of the controlled leakage shaft seal pump design.

The support of the stationary member of the number 1 seal (seal ring) is such as to allow large deflections, both axial and tilting, while still maintaining its controlled gap relative to the seal runner. Even if all the graphite were removed from the pump bearing, the shaft could not deflect far enough to cause opening of the controlled leakage gap. The spring-rate of the hydraulic forces associated with the maintenance of the gap is high enough to ensure that the ring follows the runner under very rapid shaft deflections.

Testing of pumps with the number 1 seal entirely bypassed (full system pressure on the number 2 seal) shows that relatively small leakage rates would be maintained for a sufficient time to secure the pump; even if the number 1 seal fails entirely during normal operation; the number 2 seal would maintain these small leakage rates if the proper action is taken by the operator. The plant operator is warned of number 1 seal damage by the increase in number 1 seal leakoff rate. Following warning of excessive seal leakage conditions, the plant operator should close the number 1 seal leakoff line, reduce power, and secure the pump as specified in the operating procedures. Gross leakage from the pump does not occur if the proper operator action is taken subsequent to warning of excessive seal leakage conditions.

The effect of loss of offsite power (LOOP) on the pump is to cause a temporary stoppage in the supply of injection flow to the pump seals

and also of the CCW for seal and bearing cooling. The emergency diesel generators are started automatically due to LOOP, thus restoring both seal injection and component cooling water flows within seconds. The preceding discussion satisfies the intent of NUREG 0737 (USNRC 1980), Item II.K.3.25 on protection of RCP seals due to a loss of ac power.

5.4.1.3.2 Coastdown Capability

It is important to reactor protection that the reactor coolant continues to flow for a short time after reactor trip. In order to provide this flow in a station blackout condition, each RCP is provided with a flywheel. Thus, the rotating inertia of the pump, motor, and flywheel is employed during the coastdown period to continue the reactor coolant flow for a short period. The coastdown flow transients are provided on the Figures in Section 15.3. The pump/motor system is designed for the safe shutdown earthquake (SSE) at the site. Hence, it is concluded that the coastdown capability of the pumps is maintained even under the most adverse case of a blackout coincident with the SSE. Core flow transients are provided in Sections 15.3.1 and 15.4.4. An inadvertent actuation of the shutdown seal (SDS) on the rotating assembly will not have any measurable impact on the RCP coastdown.

5.4.1.3.3 Bearing Integrity

The design requirements for the RCP bearings are primarily aimed at ensuring a long life with negligible wear, so as to give accurate alignment and smooth operation over long periods of time. The surface bearing stresses are held at a very low value, and even under the most severe seismic transients do not begin to approach loads which cannot be adequately carried for short periods of time.

Because there are no established criteria for short time stress related failures in such bearings, it is not possible to make a meaningful quantification of such parameters as margins to failure, safety factors, etc. A qualitative analysis of the bearing design, embodying such considerations, gives assurance of the adequacy of the bearing to operate without failure.

Low oil levels in the lube oil sumps signal alarms in the control room and may require shutting down of the pump if the bearing temperature rises to an unacceptable level. Each motor bearing contains embedded temperature detectors, and so initiation of failure, separate from loss of oil, is indicated and alarmed in the control room as a high bearing temperature. This, again, requires pump shutdown. If these indications are ignored, and the bearing proceeded to failure, the low melting point of Babbitt metal on the pad surfaces ensures that sudden seizure of the shaft will not occur. In this event, the motor continues to operate, as it has sufficient reserve capacity to drive the pump under such conditions. However, the high torque required to drive the pump will require high current which will lead to the motor being shutdown by the electrical protection systems.

5.4.1.3.4 Locked Rotor

It may be hypothesized that the pump impeller might severely rub on a stationary member and then seize. Analysis has shown that under such conditions, assuming instantaneous seizure of the impeller, the pump shaft fails in torsion just below the coupling to the motor, disengaging the flywheel and motor from the shaft. This constitutes a LOCF in the LOOP. Following such a postulated seizure, the motor continues to run without any overspeed, and the flywheel maintains its integrity, as it is still supported on a shaft with two bearings. Flow transients are provided on the Figures in Section 15.3.3 for the assumed locked rotor.

There are no other credible sources of shaft seizure other than impeller rubs. A sudden seizure of the pump bearing is precluded by graphite in the bearing. Any seizure in the seals results in a shearing of the antirotation pin in the seal ring. An inadvertent actuation of the shutdown seal (SDS) on a rotating assembly will not prevent sufficient cooling flow to the reactor core. The motor has adequate power to continue pump operation even after the preceding occurrences. Indications of pump malfunction in these conditions are initially by high temperature signals from the bearing water temperature detector, excessive number 1 seal leakoff indications, and by off-scale number 1 seal leakoff indications. Following these signals, pump vibration levels are checked. Excessive vibration indicates mechanical trouble and the pump is shutdown for investigation.

5.4.1.3.5 Critical Speed

The RCP shaft is designed so that its operating speed is below its first critical speed. This shaft design, even under the most severe postulated transient, gives low values of actual stress.

5.4.1.3.6 Missile Generation

Precautionary measures taken to preclude missile formation from primary coolant pump components assure that the pumps will not produce missiles under any anticipated accident condition. Each component of the primary pump motors has been analyzed for missile generation. Any fragments of the motor rotor would be contained by the heavy stator. The same conclusion applies to the pump impeller because the small fragments that might be ejected would be contained by the heavy casing. Further discussion and analysis of missile generation is contained in the WCAP-8163 Report (Westinghouse 1973).

5.4.1.3.7 Pump Cavitation

To prevent pump cavitation, the minimum NPSH required by the RCP at running speed is approximately 192 feet (approximately 85 psi). This minimum pressure will be available during RCP operation due to operating parameters required by the RCP seals. In order for the RCP controlled leakage seal to operate correctly, it is necessary to require a minimum differential pressure of approximately 200 psi

across the number 1 seal. Therefore, the minimum NPSH will be met before the pump can be operated.

5.4.1.3.8 Pump Overspeed Considerations

The RCP motor is tested without mechanical damage at overspeeds up to 125 percent of normal speed. For turbine trips actuated by either the RTS or the turbine protection system, the generator and RCP are maintained connected to the external network for 30 seconds to prevent any pump overspeed condition.

An electrical fault requiring immediate trip of the generator (with resulting turbine trip) could result in an overspeed condition. However, the turbine control system and the turbine intercept valves limit the overspeed to less than 120 percent. As additional backup, the turbine protection system has a mechanical overspeed protection trip, set at about 110 percent (of turbine speed). In case a generator trip deenergizes the pump buses, the RCP motors will be transferred to offsite power within 6 to 10 cycles. Further discussion of pump overspeed considerations is contained in WCAP-8163 Report (Westinghouse 1973).

5.4.1.3.9 Antireverse Rotation Device

Each of the RCPs is provided with an antireverse rotation device in the motor. This antireverse mechanism consists of pawls mounted on the outside diameter of the flywheel, a serrated ratchet plate mounted on the motor frame, a spring return for the ratchet plate, and two shock absorbers.

At an approximate forward speed of 70 rpm, the pawls drop and bounce across the ratchet plate; as the motor continues to slow, the pawls drag across the ratchet plate. After the motor has slowed and come to a stop, the dropped pawls engage the ratchet plate and, as the motor tends to rotate in the opposite direction, the ratchet plate also rotates until it is stopped by the shock absorbers. The rotor remains in this position until the motor is energized again. When the motor is started, the ratchet plate is returned to its original position by the spring return.

As the motor begins to rotate, the pawls drag over the ratchet plate. When the motor reaches sufficient speed, the pawls are bounced into an elevated position and are held in that position by friction resulting from centrifugal forces acting upon the pawls. While the motor is running at speed, there is no contact between the pawls and ratchet plate.

Considerable plant experience with the design of the antireverse rotation device has show high reliability of operation.

5.4.1.3.10 Shaft Seal Leakage

Leakage along the RCP shaft is controlled by three shaft seals arranged in series such that reactor coolant leakage to the containment is essentially zero. Injection flow is directed to each RCP via a seal water injection filter. It enters the pumps through a connection on the thermal barrier flange and flows to an annulus around the shaft inside the thermal barrier. Here the flow splits: a portion flows down the shaft and enters the RCS through the labyrinth seals and thermal barrier; the remainder flows up the shaft cooling the radial bearing and to the number 1 seal leakoff. After passing through the seal most of the flow leaves the pump via the number 1 seal leakoff line. Minor flow passes through the number 2 seal and its leakoff line and the number 3 seal and its leakoff line.

In the event of a loss of seal injection and CCW flow to the thermal barrier heat exchanger, the shutdown seal (SDS) will actuate when the number 1 seal temperature reaches the SDS actuation temperature range. SDS actuation limits leakage from the RCS through the RCP seal package. Leakage is limited when the SDS thermal actuator retracts due to intrusion of hot reactor coolant water into the seal area, which causes the SDS piston and polymer rings to constrict around the shaft.

5.4.1.3.11 Seal Discharge Piping

The number 1 seal drops the system pressure to that of the volume control tank. Water from each pump number 1 seal is piped to a common manifold, and through the seal water return filter and through the seal water heat exchanger where the temperature is reduced to that of the volume control tank. The number 2 and number 3 leakoff lines dump number 2 and 3 seal leakage to the primary drain transfer tank (PDTT) inside the containment (Section 9.3.3).

5.4.1.3.12 Oil Collection System

An oil collection system is installed for each reactor coolant pump (RCP) lubricating oil system. Potential locations of leakage in the RCP lube oil system have shroud enclosures. The oil will be collected within these shrouds and gravity-drained to three oil collection tanks, one for each RCP lube oil system. Each oil collection tank will have the capacity to hold the entire contents of its respective lube oil system.

5.4.1.4 Tests and Inspections

The RCP can be inspected in accordance with the ASME Code, Section XI, for inservice inspection of nuclear RCSs.

The pump casing is cast in one piece, eliminating welds in the casing. Support feet are cast integral with the casing to eliminate a weld region.

The design enables disassembly and removal of the pump internals for usual access to the internal surface of the pump casing.

The RCP nondestructive examination (NDE) program is given in Table 5.4-2.

5.4.1.5 Pump Flywheels

The integrity of the RCP flywheel is assured on the basis of the following design and quality assurance procedures.

5.4.1.5.1 Design Basis

The calculated stresses at operating speed are based on stresses due to centrifugal forces. The stress resulting from the interference fit of the flywheel on the shaft is less than 2,000 psi at zero speed, but this stress becomes zero at approximately 600 rpm because of radial expansion of the hub. The primary coolant pumps run at approximately 1,190 rpm and may operate briefly at overspeeds up to 109 percent (l,295 rpm) during loss of outside load. For conservatism, however, 125 percent of operating speed was selected as the design speed for the primary coolant pumps. The flywheels are given a shop spin test of 125 percent of the maximum synchronous speed of the motor.

The pump flywheel will see an operating temperature of at least 110°F once steady state operating conditions have been achieved. In the actual plant environment, the temperature would likely be higher because of the proximity of heat sources such as the reactor coolant circulated through the pump and attached piping.

5.4.1.5.2 Fabrication and Inspection

The flywheel consists of two thick plates bolted together. The flywheel material is produced by a process that minimizes flaws in the material and improves its fracture toughness properties, such as vacuum degassing, vacuum melting, or electroslag remelting. Each plate is fabricated from SA-533, Grade B, Class 1 steel or equivalent. Supplier certification reports are available for all plates and demonstrate the acceptability of the flywheel material on the basis of the requirements of Regulatory Guide 1.14.

Flywheel blanks are flame-cut from the SA-533, Grade B, Class 1 plates with at least 1/2 inch of stock left on the outer and bore radii for machining to final dimensions. The finished machined bores and keyways are subjected to magnetic particle or liquid penetrant examinations in accordance with the requirements of Section III of the ASME Code. The finished flywheels, as well as the flywheel material (rolled plate), are subjected to 100-percent volumetric ultrasonic, inspection using procedures and acceptance standards specified in Section III of the ASME Code.

The RCP motors are designed such that, by removing the cover to provide access, the flywheel is available to allow an inservice inspection program in accordance with requirements of Section XI of the ASME Code and the recommendations of Regulatory Guide 1.14. Section 5.2.4 provides a description of inservice inspection of the flywheels.

5.4.1.5.3 Material Acceptance Criteria

The RCP motor flywheel conforms to the following material acceptance criteria:

a. The nil ductility transition temperature (NDTT) of the flywheel material is obtained by two drop weight tests (DWT) which exhibit no-break performance at 20°F in accordance with ASTM E-208. The previously mentioned DWTs demonstrate that the NDTT of the flywheel material is no higher than 10°F.

b. A minimum of three Charpy V-notch impact specimens from each plate shall be tested at ambient (70°F) temperature in accordance with the specification ASME SA-370. The Charpy V-notch (C_V) energy in both the parallel and normal orientation with respect to the rolling direction of the

flywheel material is at least 50 ft/lb at 70°F and therefore a RT_{NDT} of 10°F can be assumed. An evaluation of flywheel overspeed has been performed which concludes that flywheel integrity will be maintained (Westinghouse 1973).

Thus, it is concluded that flywheel plate materials are suitable for use and can meet Regulatory Guide 1.14 acceptance criteria on the bases of suppliers certification data. The degree of compliance with Regulatory Guide 1.14 is further discussed in Section 1.8.

5.4.2 Steam Generator

5.4.2.1 Steam Generator Materials

5.4.2.1.1 Selection and Fabrication of Materials

All pressure boundary materials used in the steam generator are selected and fabricated in accordance with the requirements of Section III of the ASME Code. A general discussion of materials specifications is given in Section 5.2.3, with types of materials listed in Tables 5.2-2 and 5.2-3. Fabrication of reactor coolant pressure boundary (RCPB) materials is also discussed in Section 5.2.3, particularly in Sections 5.2.3.3 and 5.2.3.4.

Testing has justified the selection of corrosion-resistant Inconel-600 for the steam generator tubes (ASME SB-163) and divider plate. The interior surfaces of the reactor coolant channel heads and nozzles are clad with austenitic stainless steel. The primary side of the tube sheet is weld clad with Inconel (ASME SB-163). The tubes are roller expanded the full length of the tube sheet bore after the ends are seal welded to the tube sheet cladding. The recessed fusion welds are performed in compliance with Sections III and IX of the ASME Code and are dye penetrant inspected and leak proof tested before each tube is protractively steprolled.

After steprolling, the tube to tube sheet joint is shot peened to produce compressive stresses on the tube ID. This final step provides an improved material condition that increases the tube resistance to stress corrosion cracking.

Code cases used in material selection are discussed in Section 5.2.1. The extent of conformance with Regulatory Guides 1.84, Design and Fabrication Code Case Acceptability ASME Section III Division 1, and 1.85, Materials Code Case Acceptability ASME Section III Division 1, is discussed in Section 1.8.

During manufacture, cleaning is performed on the primary and secondary sides of the steam generator in accordance with written procedures which follow the guidance of Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants," and the ANSI Standard N45.2.1, "Cleaning of Fluid Systems and Associated

Components for Nuclear Power Plants." Onsite cleaning and cleanliness control also follow the guidance of Regulatory Guide 1.37. Cleaning process specifications are discussed in Section 5.2.3.4.

The generators are shipped from the manufacturing facility pressurized with dry nitrogen suitable for extended periods of storage. When the shell side is opened during the site construction phases, a modular internal environmental control system is provided; this modular system assures that the appropriate cleanliness and humidity conditions are maintained to prevent any damage or deterioration of the secondary side due to contamination. This modular system is designed to minimize any interference with construction-related activities. Once construction is completed, the modular environmental control system is removed, and secondary side cleanliness control is maintained in accordance with system procedures.

The fracture toughness of the materials is discussed in Section 5.2.3.3. Adequate fracture toughness of ferritic materials in the RCPB is provided by compliance with Appendix G of 10 CFR 50 and with Article NB-2300 of Section III of the ASME Code. Fracture toughness of ferritic containers for Class 2 components is provided by compliance with Article NC-2300 of the circle additionally, the requirements of GDC 1, 14, 15 and 31 of 10 CFR 50 Appendix A Amendment.

5.4.2.1.2 Steam Generator Design Effects on Materials

Several features are employed to control the regions where deposits would tend to accumulate and cause corrosion. To avoid extensive crevice areas at the tube sheet, the tubes are roller expanded to the full depth of the tube sheet bore, after their ends are seal welded to the stainless steel cladding on the primary side of the tube sheet.

5.4.2.1.3 Compatibility of Steam Generator Tubing with Primary and Secondary Coolants

As mentioned in Section 5.4.2.1.1, corrosion tests which subjected the steam generator tubing material Inconel-600 (ASME SB-163) to simulated steam generator water chemistry have indicated that the loss due to general corrosion over the plant life is insignificant compared to the tube wall thickness. Testing to investigate the susceptibility of heat exchanger construction materials to stress corrosion in caustic and chloride aqueous solutions has indicated that Inconel-600 has excellent resistance to general and pitting type corrosion in severe operating water conditions. Many reactor years of successful operation have shown the same low general corrosion rates as indicated by the laboratory tests.

Recent operating experience, however, has revealed areas on secondary surfaces where localized corrosion rates were significantly greater than the low general corrosion rates. Both intergranular corrosion and tube wall thinning were experienced in localized areas, although not at the same location or under the same environmental conditions (water chemistry, sludge composition).

Localized steam generator tube diameter reductions were first discovered during the April 1975 steam generator inspection at the Surry Unit-2 plant. This discovery was evidenced by eddy current signals, resembling those produced by scanning dents, and by difficulty in passing the standard 0.715 in diameter eddy current probe through the tubes at the intersections with the support plates. Subsequent to the initial finding, steam generator inspections at other operating plants revealed indications of denting to various degrees.

Denting is a term which describes a group of related phenomena resulting from corrosion of carbon steel in the crevices formed between the tubes and the tube support plates. The term denting has been applied to the secondary effects which include:

1. Tube diameter reduction,

2. Tube support plate hole dilation,

3. Tube support plate flow hole distortion, flow slot hour-glassing,

4. Tube support plate expansion,

5. Tube leakage, and

6. Wrapper distortion,

The mechanism which produces the effects cited involves an acid chloride environment in the tube crevices. In sequence, the process appears to occur as follows:

The crevice between the tube and the support plate is blocked as a result of deposition of chemical species present in the bulk water, including phosphate compounds, secondary system corrosion products, and minimal tube corrosion products. Once plugged, the annulus provides a site for concentration of various nominally soluble contaminants, such as chlorides, sulfates, etc. Recent studies indicate that in the absence of nonvolatile, alkalizing species, there may exist the potential for production of an acid solution by hydrolysis of such compounds as magnesium chloride, nickel phosphate, copper chloride, various ferrous salts, etc. In an acid chloride solution, the corrosion film on the carbon steel is converted from protective in character, to a thick, nonprotective oxide of low density which assumes a laminar configuration subject to disruption due to the volume mismatch between the oxide and the base metal. The buildup of the thick oxide in the nominal 14 mil radial gap between the tube and the support plate causes sufficient force to be exerted against the tube to cause plastic deformation locally. The reaction to these forces can cause distortion of the circulation holes in the plate, both the flow holes between the tubes and the central flow slots between the inlet and outlet halves of the tube bundle. In the most extreme cases, as corrosion proceeds and inplate forces accumulate, the entire plate increases in diameter and the ligaments between the holes in the plate may crack. Ovalization of the tubes at the intersections results in high strains, leading to tensile stress on the tube ID and possible leakage by intergranular cracking. A similar result may occur at the apex of the low row tubes; that is, the smallest radius U-bends, if sufficient distortion of the top support plate flow slots occurs, resulting in leg displacement, ovalization, and high strains.

The operational leakage monitoring requirements and steam generator tube ISI program are such that the tube leakage and support plate effects do not pose a safety problem with respect to release of radioactivity or effects on accident calculations, but the frequency of leakage and resultant repair shutdowns do present an economic

concern to the operators. The utilization of preventive plugging therefore serves to maintain availability and to permit orderly planning for long term corrective action.

The occurrence of denting has thus far been associated exclusively with plants having a history of chloride contamination due to condenser leakage. Moreover, it has recently been noted that Maine Yankee and Millstone Point 2, non-Westinghouse plants which have used all volatile treatment (AVT) control of secondary coolant chemistry exclusively, have apparently incurred denting also; sea water is used for cooling the condensers at both of these plants.

Research into the causes of denting was initiated shortly after the discovery of the denting condition. Initially dented tubes were removed for laboratory examination. Subsequently, tube support plate samples containing sections of tubing were also removed for analysis from operating plants.

The initial hard data on the nature of the denting phenomenon were derived from these tube/support plate samples which revealed the thick oxide buildup, the tube diameter reduction, and chemical makeup of the crevice-filling materials. It was observed that there was only minor corrosive attack on the tube material, approximately 0 to 2 mil circumferential thinning, and that the crevice contained a thick layer of almost pure magnetite (Fe_3O_4); other chemical constituents included Inconel-metal-phosphate corrosion products close to the tube, and general secondary system contaminants between the Fe_3O_4 and the phosphate layer. There was evidence of copper deposits and the oxide was laced with chlorides.

Armed with those general observations, a series of crevice-with-contaminants test geometries were evaluated; denting was produced first in reverse as bulging when a carbon steel plug was inserted into an Inconel tube to form the crevice; later heated crevice assemblies with heat transfer were shown to be effective dent simulators; finally denting in model boilers equipped with plant-type geometrical configurations was demonstrated. While pure, uncontaminated AVT environments have to date been found to be innocuous, it has been shown that the PO_4 to AVT transition was unnecessary to initiate the denting process. Only the presence of acid chloride solutions has been found to be a common factor. Nickel chloride, ferrous, or cupric chloride solutions have been shown to be corrosive, and have also produced measurable denting. Thus far, test data indicate that phosphates, calcium hydroxide, and borates seem to retard the dent process; morpholine, among the common volatile amines, shows a beneficial effect on the corrosion rate of carbon steel.

Model boiler tests have been used to evaluate the adequacy of the AVT chemistry specifications adopted in 1974. With one significant alteration, the specifications appear to be adequate to preserve tube

integrity: the frequency and the length of time above the chloride limit for normal operation (0.15 ppm) must be limited.

Operating experience, verified in numerous steam generator inspections, indicates that the tube degradation associated with phosphate water treatment is not occurring where only AVT has been utilized. Adherence to the AVT chemical specifications and close monitoring of the condenser integrity will assure the continued good performance of the steam generator tubing.

The adoption of the AVT control program by BVPS-2 will minimize the possibility for recurrence of the tube wall thinning phenomenon related to phosphate chemistry control. Successful AVT operation requires maintenance of low concentrations of impurities in the steam generator water, thus reducing the potential for formation of highly concentrated solutions in the low flow zone, the precursor of the corrosion mechanisms. By restriction of the total alkalinity in the steam generator and prohibition of extended operation with free alkalinity, the AVT program should minimize the possibility of intergranular corrosion in localized areas due to excessive levels of free caustic. Secondary side water chemistry is presented in Section 10.3.5.

Laboratory testing has shown that the Inconel-600 tubing is compatible with the AVT environment. Isothermal corrosion testing in high purity water has shown that commercially produced Inconel-600 exhibiting normal microstructures tested at normal engineering stress levels does not suffer intergranular stress corrosion cracking in extended exposure to high temperature water. These tests also showed that no general type of corrosion occurred. A series of autoclave tests in reference secondary water with planned excursions has produced no corrosion attack after 1,938 days of testing on any as-produced Inconel-600 tube samples.

All volatile treatment chemistry control has been employed in plant operations successfully for considerable periods. Plants with stainless steel tubes which have demonstrated successful AVT operation include Selni, Sena, and Yankee-Rowe. Selni has operated with AVT since 1964, Sena since 1966, and Yankee-Rowe since 1967.

Among the plants with Inconel tubes which have operated successfully with AVT are the Hanford N-Reactor and Prairie Island No. 2. The Hanford N-Reactor has operated with AVT since 1964. There have been no tube leaks and annual eddy current inspections have revealed no corrosion defects.

Additional extensive operating data is presently being accumulated with the conversion to AVT chemistry. A comprehensive program of steam generator inspections, including the guidelines of Regulatory Guide 1.83, will ensure detection and correction of any unanticipated degradation that might occur in the steam generator tubing.

5.4.2.1.4 Cleanup of Secondary Side

During steam generator shutdown, tube inspection results may indicate the need for cleaning. Sludge lancing is capable of being performed by inserting a hydraulic jet through access openings (inspection ports) to loosen corrosion deposits. The hydraulic water jet impinges at the tube surface at high velocity causing the deposits to loosen and wash down to the top of the tube sheet. These deposits are then removed utilizing a suction pump.

Access is available to perform sludge lancing utilizing 2-inch inspection ports and 6-inch hand holes located just above the tube sheet surface.

Lancing is performed by inserting the hydraulic jet into each hand hole for traversing the tube lane and the periphery of the two tube bundles just above the tube sheet surface. The two inspection ports located 90 degrees from the hand holes can be used to clean tubes which are located furthest away from the hand holes. This method, when used in conjunction with an AVT chemical treatment program during normal operation, will provide sufficient cleaning of the exterior tube surface near the tube sheet.

5.4.2.2 Steam Generator Inservice Inspection

5.4.2.2.1 Access

The steam generator contains design aspects which provide access for inservice inspection and replacement or repair of Class 1 and 2 components including individual tubes. This allows for implementation of Section XI of the ASME Code, Division 1, "Rules for Inspection and Testing of Light-Water-Cooled Plants," Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes," as specified in FSAR Section 1.8 and FSAR Section 5.2.4, Inservice Inspection and Testing of Reactor Coolant Pressure Boundary. Access openings are provided to 1) inspect, repair, or replace components; 2) detect and locate tubes with a wall defect penetration 20 percent or more, and 3) perform volumetric inspections on Safety Class 1 welds on the primary side. These openings include four manways (two for access to both side of the reactor coolant channel head, and two for inspection and maintenance of the steam dryers), and at least four 2-inch inspection ports and two 6-inch hand holes located just above the tube sheet surface. Insulation can be removed as necessary to provide the required access.

5.4.2.2.2 Baseline Inspection

All tubes in each steam generator will be given a baseline volumetric examination prior to service using eddy current techniques and equipment in accordance with Regulatory Guide 1.83.

The vessel welds, attachments, and bolting will be examined as required by ASME XI after the completion of the pressure tests required by ASME III. Examination results will be retained for comparison to future inservice inspection data.

5.4.2.2.3 Steam Generator Inspection Program

During each inservice inspection period, examinations and repairs of the steam generator vessel (as applicable) will be performed as required by ASME XI. Inservice inspections of the steam generator vessel will be performed in accordance with the frequency specified in Technical Specifications.

Scope, frequency and methods for steam generator tube inspections are in accordance with a steam generator program required by Technical Specifications. Required program provisions, such as for condition monitoring assessments and tube inspections are specifically described in the Technical Specifications.

Inservice inspection reports of steam generator tubes will be provided in accordance with the Technical Specifications.

5.4.2.3 Design Bases

Steam generator design data are give in Table 5.4-5. Code classifications of the steam generator components are given in Section 3.2. Although the ASME classification for the secondary side is specified to be Class 2, the current philosophy is to design all pressure retaining parts of the steam generator, and thus both the primary and secondary pressure boundaries, to satisfy the criteria specified in Section III of the ASME Code for Class 1 components. The design stress limits, transient conditions, and combined loading conditions applicable to the steam generator are discussed in Section 3.9.1. Estimates of radioactivity levels anticipated in the secondary side of the steam generators during normal operation, and the bases for the estimates are given in Chapter 11. The accident analysis of a steam generator tube rupture is discussed in Chapter 15.

The internal moisture separation equipment is designed to ensure that moisture carryover does not exceed 0.25 percent by weight under the following conditions:

1. Steady state operation up to 100 percent of full load steam flow, with water at the normal operating level.

2. Loading or unloading at a rate of 5 percent of full power steam flow per minute in the range from 15 percent to 100 percent of full load steam flow.

3. A step load change of 10 percent of full power in the range from 15 percent to 100 percent full load steam flow.

The water chemistry on the reactor side is selected to provide the necessary boron content for reactivity control and to minimize corrosion of RCS surfaces. The water chemistry of the steam side and its effectiveness in corrosion control are discussed in Chapter 10. Compatibility of steam generator tubing with both primary and secondary coolants is discussed further in Section 5.4.2.1.3.

The steam generator is designed to minimize unacceptable damage from mechanical or flow induced vibration. Tube support adequacy is discussed in Section 5.4.2.5.3. The tubes and tube sheet are analyzed in WCAP-7832-A (DeRosa et al 1978) and confirmed to withstand the maximum accident loading conditions as they are defined in Section 3.9.1. Further consideration is given in Section 5.4.2.5.4 to the effect of tube wall thinning on accident condition stresses.

5.4.2.4 Design Description

The steam generator shown on Figure 5.4-3 is a vertical shell and U-tube evaporator with integral moisture separating equipment. On the primary side, the reactor coolant flows through the inverted U-tubes, entering and leaving through nozzles located in the hemispherical bottom head of the steam generator. The head is divided into inlet and outlet chambers by a vertical divider plate extending from the head to the tube sheet.

Steam is generated on the shell side, flows upward and exits through the outlet nozzle at the top of the vessel. Feedwater enters the steam generator at an elevation above the top of the U-tubes through a feedwater nozzle. A protective liner is designed into the feedwater nozzle to minimize feedwater pipe cracking due to an introduction of cold auxiliary feedwater into a hot steam generator. The water is distributed circumferentially around the steam generator by means of a feedwater ring and then flows through an annulus between the tube wrapper and shell. The feedwater enters the ring via a welded thermal sleeve connection and leaves it through inverted J-tubes located at the flow holes which are at the top of the ring. The feedring is designed to minimize conditions which can result in waterhammer occurrences in the feedwater piping. The water sweeps across the tube sheet where it begins to absorb heat and rises through the tube bundle. Flow blocking devices discourage the water from flowing up the bypass lane. The water-steam mixture which emerges at the top of the tube bundle is directed through the three centrifugal moisture separators which remove most of the entrained water from the steam. The steam continues to the secondary separators for further moisture removal, increasing its quality to a minimum of 99.75 percent. The moisture separators return the separated water through the annulus between the shell and tube bundle wrapper where it mixes with the feedwater for another circulation through the steam generator. Dry steam exits through the outlet nozzle which is provided with a steam flow restrictor, described in Section 5.4.4.

5.4.2.5 Design Evaluation

5.4.2.5.1 Forced Convection

The effective heat transfer coefficient is determined by the physical characteristics of the steam generator and the fluid conditions in the primary and secondary systems for the normal 100-percent design case. It includes a conservative allowance for fouling and uncertainty. Adequate heat transfer area is provided so that the full design heat removal rate is achieved.

5.4.2.5.2 Natural Circulation Flow

The driving head created by the change in coolant density as it is heated in the core and rises to the outlet nozzle initiates convection circulation. This circulation is enhanced by the fact that the steam generators, which provide a heat sink, are at a higher elevation than the reactor core which is the heat source. Thus, natural circulation is assured for the removal of decay heat during hot shutdown in the unlikely event of loss of forced circulation.

5.4.2.5.3 Mechanical and Flow Induced Vibration Under Normal Operation

In the design of BVPS-2 steam generators, the possibility of degradation of tubes due to either mechanical or flow induced excitation is thoroughly evaluated. This evaluation includes an extensive research program with tube vibration model tests as well as a detailed analysis of the tube support systems.

In evaluating degradation due to vibration, consideration is given to such sources of excitation as those generated by secondary fluid flow on the outside of the tubes, primary fluid flowing within the tubes, and mechanically induced vibration. During normal operation the effects of primary fluid flow and mechanically induced vibrations are considered to be negligible and should cause little concern. Thus, the primary source of tube vibrations is the hydrodynamic excitation by the secondary fluid on the outside of the tubes.

Consideration of secondary flow induced vibration involved 2 types of flow, parallel and cross, and is evaluated in 3 regions:

1. At the entrance of the downcomer feed to the tube bundle (cross flow),

2. Along the straight sections of the tube (paralleled flow), and

3. In the curved tubed section of the U-bend (cross flow).

For the case of parallel flow, analysis is done to determine the vibratory deflections in order to verify that the flow velocities are sufficiently below those required for damaging fatigue or impacting vibratory amplitude. The support system is deemed adequate to preclude parallel flow excitation.

For the case of cross flow excitation, several possible mechanisms of tube vibration exist. The design problem is to ascertain that the tube natural frequency is well above the vortex shedding frequency and will not cause fluid elastic vibration. In order to achieve this, adequate tube supports are provided.

While the behavior of tube arrays under cross flow in actual operating units is given consideration, the high temperature and pressure limits the amount and quality of information obtained therefrom. As a result, it was deemed prudent to undertake a research program that would allow in-depth study and testing in this area of interest. Facilities included a water tunnel and a wind tunnel, which were specifically built to study the vibration behavior of tubes in arrays.

The results of this research confirmed both the vortex shedding and the fluid elastic mechanisms. The fluid elastic mechanism is not as extensively investigated as the vortex shedding mechanism in the available literature but could be a source of vibration failure. The BVPS-2 steam generators were evaluated on these bases and found adequately designed. Testing is also conducted using specific parameters of the steam generator in order to show that the support system is adequate.

In summary, it can be stated that a check of support adequacy is made using all published techniques believed appropriate to heat exchanger tube support design. In addition, the tube support system is consistent with accepted standards of heat exchanger design utilized throughout the industry (spacing, clearance, etc). Furthermore, the design techniques are supplemented with a continuing research and development program to understand the complex mechanism of fluid-structure interaction, and it should be noted that successful operational experience with several steam generator designs has given confidence in the overall approach to the tube support design problem.

5.4.2.5.4 Allowable Tube Wall Thinning Under Accident Conditions

An evaluation is performed to determine to the extent of tube wall thinning that can be tolerated under accident conditions. The worst-case loading conditions are assumed to be imposed upon uniformly thinned tubes at the most critical location in the steam generator. Under such a postulated design basis accident, vibration is of short enough duration that there is no endurance problem. The results of a study made on Model 51 (.875-inch nominal diameter, 0.050-inch nominal thickness) tubes under accident loading (discussed in DeRosa et al 1978), showed that a minimum wall thickness of 0.021 inch would have a maximum faulted condition stress (due to combined LOCA and SSE loads) that is less than the allowable limit.

The corrosion loss is based on a conservative weight loss rate for Inconel tubing in flowing 650°F primary side reactor coolant fluid. The weight loss, when equated to a thinning rate and projected over a 40-year design objective including appropriate reduction for initial protective film formation, is equivalent to 0.000083-inch thinning. The assumed corrosion loss of 0.003 inch leaves a conservative 0.002917 inch for general corrosion thinning on the secondary side. While the S/Gs were designed for a 40 year life, the life of the plant has been extended to 60 years via License Renewal. Aging of the steam generator tubes is managed by the Steam Generator Tube Integrity Program (Section 19.1.38) to provide assurance that steam generator tube integrity is maintained consistent with the plant’s licensing basis.

The steam generator tubes, existing originally at their minimum wall thickness and reduced by a very conservative general corrosion loss, still provide an adequate safety margin.

5.4.2.6 Quality Assurance

The steam generator NDE is given in Table 5.4-6. Quality assurance records are maintained according to the guidelines in 10 CFR 50 Appendix B.

Radiographic inspection and acceptance standard shall be in accordance with the requirements of Section III of the ASME Code.

Liquid penetrant inspection is performed on weld deposited tube sheet cladding, channel head cladding, tube to tube sheet weldments, and weld deposit cladding. Liquid penetrant inspection and acceptance standard are in accordance with the requirements of Section III of the ASME Code.

Magnetic particle inspection is performed on the tube sheet forging, channel head casting, nozzle forgings, and the following weldments:

1. Nozzle to shell,
2. Support brackets,
3. Instrument connection (primary and secondary),
4. Temporary attachments after removal, and
5. All accessible pressure retaining welds after shop hydrostatic test.

Magnetic particle inspection and acceptance standard are in accordance with requirements of Section III of the ASME Code.

An ultrasonic test is performed on the tube sheet forging, tube sheet cladding, secondary shell and head plate, and nozzle forgings.

The heat transfer tubing is subjected to eddy current volumetric tests.

Hydrostatic tests are performed in accordance with Section III of the ASME Code. Ultrasonic testing may be utilized, as needed.

In addition, the heat transfer tubes are subjected to a hydrostatic test pressure prior to installation into the vessel which is not less than 1.25 times the primary side design pressure multiplied by the ratio of the material allowable stress at the testing temperature.

5.4.3 Reactor Coolant Piping

5.4.3.1 Design Bases

The RCS piping is designed and fabricated to accommodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions. Stresses are maintained within the limits as defined in Section III of the ASME Nuclear Power Plant Components Code for Class I components. Code and material requirements are provided in Section 5.2.

Materials of construction are specified to minimize corrosion/erosion and ensure compatibility with the operating environment.

The piping in the RCS is Seismic Category I, Safety Class I and is designed and fabricated in accordance with ASME Section III, Class I requirements.

Stainless steel pipe conforms to ANSI B36.19 for sizes 1/2 inch through 12 inches and wall thickness Schedules 40S through 80S. Stainless steel pipe outside of the scope of ANSI B36.19 conforms to ANSI B36.10.

The minimum wall thickness of the loop pipe and fittings are not less than that calculated using the ASME III Class 1, formula three, of Paragraph NB-3641.1 with an allowable stress value of 17,550 psi. The pipe wall thickness for the pressurizer surge line is Schedule 160. The minimum pipe bend radius is five nominal pipe diameters; ovality does not exceed 6 percent.

All butt welds, branch connection nozzle welds, and boss welds shall be of a full penetration design.

Processing and minimization of sensitization are discussed in Sections 5.2.3 and 5.2.5.

Flanges conform to ANSI B16.5.

Socket weld fittings and socket joints conform to ANSI B16.11.

5.4.3.2 Design Description

Principal design data for the reactor coolant piping are given in Table 5.4-7. Beaver Valley Power Station - Unit 2 is provided with loop stop valves on each hot and cold leg. These valves are described in Section 5.4.12.

Reactor coolant loop pipe is seamless forged. Reactor coolant loop fittings are cast seamless without longitudinal or electroslag welds. Pipe and fittings comply with the requirements of the ASME Code, Section II, Parts A and C, Section III, and Section IX.

The RCS piping is specified in the smallest sizes consistent with system requirements. This design philosophy results in the reactor inlet and outlet piping diameters given in Table 5.4-7. The line between the steam generator and the pump suction is larger to reduce pressure drop and improve flow conditions to the pump suction.

The reactor coolant piping and fittings which make up the loops are austenitic stainless steel. All smaller piping which comprise part of the RCS such as the pressurizer surge line, spray and relief line, loop drains, and connecting lines to other systems are austenitic stainless steel. The thermal sleeve in the charging line connection is also austenitic stainless steel. The nitrogen supply line for the pressurizer relief tank is carbon steel. All joints and connections are welded, except for the pressurizer code safety valves, where flanged joints are used.

All piping connections from auxiliary systems are made above the horizontal centerline of the reactor coolant piping, with the exception of:

1. Residual heat removal (RHR) pump suction lines, which are 45 degrees down from the horizontal centerline. This enables the water level in the RCS to be lowered in the reactor coolant pipe while continuing to operate the residual heat removal system (RHRS), should this be required for maintenance.

2. Loop drain lines and the connection for temporary level measurement of water in the RCS during refueling and maintenance operation.

3. The differential pressure taps for flow measurement, which are downstream of the steam generators on the first 90-degree elbow.

4. The pressurizer surge line, which is attached at the horizontal centerline.

5. The safety injection connections of the hot leg, for which inservice inspection requirements and space limitations dictate location on the horizontal centerline.

6. Two of the three narrow Range RTD thermowell bosses in each hot leg.

7. One hot leg sample connection and loop Wide Range RTD thermowells, all located on the horizontal centerline.

Penetrations into the coolant flow path are limited to the following:

1. The spray line inlet connections extend into the cold leg piping in the form of a scoop so that the velocity head of

the reactor coolant loop flow adds to the spray driving force.

2. The reactor coolant sample system taps protrude into the main stream to obtain a representative sample of the reactor coolant.

3. The resistance temperature detector hot leg scoops extend into the reactor coolant. In the original design, these scoops collected a representative temperature sample for the RTD minifold. They now provide a convenient location for narrow range thermowell mounted RTDs.

4. The wide range hot and cold leg temperature detectors are located in resistance thermowells that extend into the reactor coolant pipes.

Each hot leg has three narrow range, thermowell mounted, fast response RTDs located in approximately the same plane 120 degrees apart. These RTDs extend into the reactor coolant fluid, sensing the temperature at three distinct locations within the hot leg pipe. These three measurements are electronically averaged to provide a representative T_{hot} indication.

The cold leg is provided with a dual element narrow range, thermowell mounted, fast response RTD. One element provides the cold leg temperature measurement and the other element is an installed spare.

Signals from these instruments are used to compute the reactor coolant ΔT (temperature of the hot leg, T_{hot} minus the temperature

of the cold leg, T_{cold}) and an average reactor coolant temperature (T_{avg}). The T_{avg} for each loop is indicated on the main control board.

The RCS piping includes those sections of piping interconnecting the reactor vessel, steam generator, RCP, and loop stop valves. It also includes the following:

1. Charging line from the system isolation valve up to the branch connections on the reactor coolant loop.

2. Letdown line and excess letdown line from the branch connections on the reactor coolant loop to the system isolation valve.

3. Pressurizer spray lines from the reactor coolant cold legs to the spray nozzle on the pressurizer vessel.

4. Residual heat removal lines to or from the reactor coolant loops up to the designated check valve or isolation valve.

5. Safety injection lines from the designated check valve to the reactor coolant loops.

6. Accumulator lines from the designated check valve to the reactor coolant loops.

7. Loop fill, loop drain, sample*, and instrument*, lines to or from the designated isolation valve to or from the reactor coolant loops.

8. Pressurizer surge line from one reactor coolant loop hot leg to the pressurizer vessel surge nozzle.

9. Loop bypass lines between the loop stop valves of each loop.

10. Pressurizer spray scoop, sample connection* with scoop, reactor coolant RTD thermowell installation boss, and the temperature RTD thermowell itself.

11. All branch connection nozzles attached to reactor coolant loops.

12. Pressure relief lines from nozzles on top of the pressurizer vessel up to and through the power operated pressurizer relief valves (PRVs) and pressurizer safety valves.

13. Seal injection water to or from the RCP inside the reactor containment.

14. Auxiliary spray line from the isolation valve to pressurizer spray line header.

15. Sample lines*, instrument lines*, and vent lines* from pressurizer to the isolation valve.

16. Reactor vessel head vent lines from the reactor vessel head to the excess letdown lines.

Note: *Lines with a 3/8-inch flow restricting orifice located below normal pressurizer level qualify as Seismic Category II; in the event of a break in one of these Category II lines, the normal makeup system is capable of providing makeup flow while maintaining pressurizer water level.

Details of the materials of construction and codes used in the fabrication of reactor coolant piping and fittings are discussed in Section 5.2.1.

5.4.3.3 Design Evaluation

Piping load and stress evaluation for normal operating loads, seismic loads, accident loads, and combined normal, accident and seismic loads is discussed in Section 3.9.1.

5.4.3.3.1 Material Corrosion/Erosion Evaluation

The water chemistry is specified and maintained to minimize corrosion. A periodic analysis of the coolant chemical composition is performed to verify that the reactor coolant quality meets the specifications.

The configuration and weld finishes are designed to facilitate inservice inspection as required by ASME Section XI. Pursuant to this, all pressure retaining welds out to the second valve that delineates the RCS boundary are provided with removable insulation to facilitate examination.

Components constructed with stainless steel will operate satisfactorily under normal plant chemistry conditions in PWR systems, because chlorides, fluorides, and particularly oxygen, are controlled to very low levels (Section 5.2.3).

Periodic analysis of the coolant chemical composition is performed to monitor the adherence of the system to desired reactor coolant water quality listed in Table 5.2-5. Maintenance of the water quality to minimize corrosion is accomplished using the chemical and volume control system (CVCS) and sampling system which are described in Section 9.3.

5.4.3.3.2 Sensitized Stainless Steel

Sensitized stainless steel is discussed in Section 5.2.3.

5.4.3.3.3 Contaminant Control

Copper, low melting temperature alloys, mercury, and lead are prohibited to preclude contamination of stainless steel and Inconel. Colloidal graphite is the only permissible thread lubricant.

Prior to application of thermal insulation, the austenitic stainless steel surfaces are cleaned and analyzed to a halogen limit of 0.0015 mg Cl/dm^2 and 0.0015 mg F/dm^2.

5.4.3.4 Tests and Inspections

The RCS piping NDE program is given in Table 5.4-8.

Volumetric examination is performed throughout 100 percent of the wall volume of each pipe and fitting in accordance with the applicable requirements of Subsection NB of the ASME Section III code for all pipe 27 1/2 inches and larger. All unacceptable defects are eliminated in accordance with the requirements of the same section of the code.

A liquid penetrant examination is performed on both the entire outside and inside surfaces of each finished fitting in accordance with the criteria of ASME Section III. Acceptance standards are in accordance with the applicable requirements of ASME Section III.

The pressurizer surge line conforms to SA-376 Grade 304, 304N, or 316 with supplementary requirements S2 (transverse tension tests), and S6 (ultrasonic test). The S2 requirement applies to each length of pipe. The S6 requirement applies to 100 percent of the piping wall volume.

The end of pipe sections, branch ends, and fittings are machined back to provide a smooth weld transition adjacent to the weld path.

In addition, all piping not supplied by the nuclear steam supply system (NSSS) vendor, which forms part of the RCPB, is examined in accordance with the applicable subsection of ASME III.

5.4.4 Main Steam Line Flow Restrictor

5.4.4.1 Design Basis

The outlet nozzle of the steam generator is provided with a flow restrictor designed to limit steam flow in the unlikely event of a break in the main steam line. A large increase in steam flow will create a back pressure which limits further increase in flow. Several protective advantages are thereby provided: rapid rise in

containment pressure is prevented, the rate of heat removal from the reactor coolant is kept within acceptable limits, thrust forces on the main steam line piping are reduced, and stresses on internal steam generator components, particularly the tube sheet and tubes, are limited. The restrictor is also designed to minimize the unrecovered pressure loss across the restrictor during normal operation.

5.4.4.2 Design Description

The flow restrictor consists of a support assembly with seven Inconel venturi inserts. The support assembly is welded into the steam outlet nozzle forging. The inserts are arranged with one venturi at the centerline of the outlet nozzle and the other six equally spaced around it. These Inconel venturi inserts are welded to the Inconel cladding on the inner surface of the support assembly. The flow area of the restrictor is 1.4 ft^2.

5.4.4.3 Design Evaluation

The flow restrictor design has been analyzed to assure its structural adequacy. The equivalent throat diameter of the steam generator outlet is 16 inches, and the resultant pressure drop through the restrictor at 100-percent steam flow is approximately 3.67 psi. This is based on a design flow rate of 3.87×10^6 lb/hr. Materials of construction and manufacturing of the flow restrictor are in accordance with Section III of the ASME Code.

5.4.4.4 Tests and Inspections

Since the restrictor is not a part of the steam system boundary, no tests and inspection beyond those during fabrication, are anticipated.

5.4.5 Main Steam Line Isolation System

Main steam line isolation is discussed with the main steam system in Section 10.3. The main steam isolation valves (MSIVs) reduce potential leakage of radioactivity to the environment following a main steam line break (MSLB) by performing their closure function.

Following an MSLB outside the containment, automatic closure of these valves prevents blowdown of more than one steam generator, thereby preventing fuel damage and the release of radioactivity to the environment.

Following an MSLB inside the containment, automatic closure of these valves prevents excessive blowdown of more than one steam generator and minimizes potential containment overpressurization.

Further discussion of the sequence of events occurring upon MSIV closure is included in Section 15.1.5.

5.4.6 Reactor Core Isolation Cooling System

This section is not applicable to BVPS-2.

5.4.7 Residual Heat Removal System

The RHRS transfers heat from the RCS to the primary plant component cooling water system to reduce the temperature of the reactor coolant to the cold shutdown temperature at a controlled rate during the second part of normal plant cooldown and maintains this temperature until the plant is started up.

The RHRS also is used to transfer refueling water from the refueling cavity and transfer canal to the refueling water storage tank (RWST) at the end of the refueling operations.

Nuclear units employing the same RHRS design as BVPS-2 are given in Section 1.3.

5.4.7.1 Design Bases

Residual heat removal system design parameters are listed in Table 5.4-9.

The RHRS can be placed in operation within 4 hours after reactor shutdown when the temperature and pressure of the RCS are approximately 350°F and 400 psig, respectively. For the rated thermal power of 2900 MWt and allowing for an additional 17 MWt due to calorimetric error (0.6%), the RHRS is capable of reducing the temperature of the reactor coolant from 350°F to 140°F in approximately 47 hours after the RHRS is placed in operation, assuming that the RHRS is placed in operation at 4 hours after reactor shutdown and that two RHR heat exchangers, two RHR pumps, three CCW heat exchangers, and two CCW pumps are in service. The time required under these conditions, to reach 212°F is approximately 12 hours after the RHRS is placed in operation. The heat load handled by the RHRS during the cooldown transient includes residual and decay heat from the core and RCP heat. The heat load is based on the decay heat fraction that exists at 51 hours following reactor shutdown from an extended run at full power.

Assuming that only one RHR heat exchanger, one RHR pump, three CCW heat exchangers, and two CCW pumps are in service, the RHRS is capable of reducing the RCS temperature from 350°F to less than 200°F within approximately 54 hours after the RHRS is placed in operation. The time required, under these conditions, to reach 212°F is approximately 34 hours.

The RHRS is also designed to operate in conjunction with the other systems of the cold shutdown design in order to address the functional requirements proposed by Regulatory Guide 1.139, Guidance for Residual Heat Removal to Achieve and Maintain Cold Shutdown. The cold shutdown design enables the RCS to be taken from hot standby to conditions that will permit initiation of RHRS operation within 36 hours. For this case, one RHR pump, one RHR heat exchanger, two CCW pumps, and two CCW heat exchangers are in service. A loss of offsite power is assumed, so there is no RCP heat input and minimal CCW auxiliary heat loads.

Cooldown to 200°F can be achieved in approximately 7 hours after the RHRS is placed in service, which corresponds to 43 hours after reactor shutdown. The reliability of the cold shutdown design is discussed in paragraph 5.4.7.2.6 and Appendix 5A.

The RHRS is designed to be isolated from the RCS whenever the RCS pressure exceeds the RHRS design pressure. The RHRS is isolated from the RCS by two motor-operated valves (MOVs) in series on each pump suction line. Each MOV is interlocked to prevent valve opening unless the RCS pressure is below approximately 360 psig and to automatically close if RCS pressure exceeds approximately 700 psig. The RHRS is isolated from the RCS on the discharge side by a check valve and a normally closed MOV in each RCS return line. Each MOV is interlocked to prevent valve opening unless the RCS pressure is below approximately 360 psig and to automatically close if the RCS pressure exceeds approximately 700 psig. (The check valve is part of the emergency core cooling system (ECCS) and is shown on Figure 6.3-1). The auto closure interlock may be manually defeated during normal RHR operation to increase the plant shutdown safety posture by reducing the potential for inadvertent RHR isolation valve closure.

Each inlet line to the RHRS is equipped with a PRV designed to relieve the combined flow of two charging pumps at the relief valve set pressure. These relief valves also protect the RCS from inadvertent overpressurization during plant cooldown or startup.

The RHRS is designed for a single unit and is not shared with Beaver Valley Power Station - Unit 1.

The RHRS is designed to be fully operable from the control room for normal operation. Remote manual operations required for the operator are: 1) opening the suction and discharge isolation valve, 2) positioning the flow control valves downstream of the RHRS heat exchangers, and 3) starting the RHRPs. The RHRS is designed to accept any single active failure without the loss of its intended cooling function. A failure modes and effects analysis has been performed which demonstrates that the RHRS, because of its redundant two train design, is able to accommodate any credible active failure with the only effect being an extension in the cooldown time (Table 5.4-10). For two low probability electrical system single failures, that is, failure in the suction isolation valve interlock circuitry, or diesel generator failure in conjunction with LOOP, limited operator action outside the control room is required to open the suction isolation valves. There are no MOVs in the RHRS which are subject to flooding after a LOCA or steam line break accident. Although it is considered to be of low probability, spurious operation of a single MOV can be accepted since redundant isolation valves are provided in each flow path.

Missile protection against dynamic effects associated with the postulated rupture of piping, and a seismic design are discussed in Section 3.5, 3.6, and 3.7, respectively.

5.4.7.2 System Design

5.4.7.2.1 Schematic Diagram

The RHRS, as shown on Figure 5.4-5 consists of two RHR heat exchangers, two residual heat removal pumps (RHRPs), and the associated piping, valves, and instrumentation necessary for operational control. The inlet lines to the RHRS are connected via a single suction header to the hot leg of one of the reactor coolant loops, while the return lines are connected to the cold legs of two reactor coolant loops, via the ECCS accumulator injection lines. The entire system is located inside the reactor containment.

The RHRS suction lines are isolated from the RCS by two MOVs in series. Each discharge line to the accumulator injection line is isolated from the RCS by a check valve and a normally closed MOV. (The check valve is part of the ECCS and is shown on Figure 6.3-1.)

During RHRS operation, reactor coolant flows from the RCS to the RHRPs, through the tube side of the residual heat exchangers, and back to the RCS. The heat is transferred to the primary plant CCW circulating through the shell side of the residual heat exchangers.

Coincident with operation of the RHRS, a portion of the reactor coolant flow may be diverted from downstream of the RHR heat exchangers to the CVCS low pressure letdown line for cleanup and/or pressure control. By regulating the diverted flow rate and the charging flow, the RCS pressure may be controlled. Pressure regulation is necessary to maintain the pressure range dictated by the fracture prevention criteria requirements of the reactor vessel and by the number 1 seal differential pressure and NPSH requirements of the RCPs.

The RCS cooldown rate is manually controlled by regulating the reactor coolant flow through the tube side of the RHR heat exchangers. A line containing a flow control valve bypasses each residual heat exchanger and is used to obtain the desired reactor coolant temperature while maintaining a constant return flow to the RCS. Instrumentation is provided to monitor system pressure, temperature, and total flow.

The RHRS is also used during refueling to transfer water from the refueling cavity and transfer canal to the RWST. After a refueling, the water level in the refueling cavity is lowered through the vessel to the vessel flange by use of a RHRP discharging into the RWST. The remainder of the water is removed via a drain connection at the bottom of the refueling canal. If desired, the refueling water can be diverted through the fuel pool cleanup system.

The line from the RHS system to the RWST may also be used to return water from the RCS to the RWST during or following tests that inject large quantities of water into the RCS. Returning the water to the RWST will reclaim water instead of transferring the water to the coolant recovery tanks for processing. The line may be used by approved procedures under administrative control when the RCS is vented to atmosphere. Examples of the procedures that may use the flow path are SIS full flow tests or SIS accumulator discharge tests.

When the RHRS is in operation, the water chemistry is the same as that of the reactor coolant. Provision is made for process sampling system to extract samples from the flow of reactor coolant downstream of the residual heat exchangers.

The RHRS suction isolation valves in each inlet line from the RCS are separately interlocked to prevent their opening unless the RCS pressure is below approximately 360 psig, and to automatically close if RCS pressure exceeds approximately 700 psig. The motor operated isolation valve in each discharge line is interlocked to prevent valve opening unless the RCS pressure is below approximately 360 psig and to automatically close if the RCS pressure exceeds approximately 700 psig.

Sections 5.4.7.2.4 and 7.5.2 further describe these interlocks.

5.4.7.2.2 Equipment and Component Descriptions

The materials used to fabricate RHRS components are in accordance with the applicable code requirements. All parts of components normally in contact with borated water are fabricated or clad with austenitic stainless steel or equivalent corrosion resistant material. Component parameters are given in Table 5.4-11.

Residual Heat Removal Pumps

Two pumps are installed in the RHRS. The pumps are sized to deliver reactor coolant flow through the RHR heat exchangers to meet the plant cooldown requirements. The use of two separate RHR trains assures that cooling capacity is only partially lost should one pump become inoperative.

The RHRPs are protected from overheating and loss of suction flow by miniflow bypass lines that assure flow to the pump suction. A throttling valve located in each miniflow line is adjusted and locked in place during initial system alignment to assure required miniflow.

A pressure sensor in each pump discharge header provides a signal for an indicator in the control room. A high pressure alarm is also actuated by the pressure sensor.

The two pumps are vertical, centrifugal units with mechanical seals on the shafts. All pump surfaces in contact with reactor coolant are austenitic stainless steel or equivalent corrosion resistant material.

Residual Heat Removal Heat Exchangers

Two RHR heat exchangers are installed in the system. The heat exchanger original design is based on the original rated thermal power (2652 MWt) heat load and temperature differences between reactor coolant and CCW existing 20 hours after reactor shutdown when the temperature difference between the two systems is small. The performance of the RHR heat exchangers for the rated thermal power of 2900 MWt is described in Section 5.4.7.1.

The installation of two heat exchangers in separate and independent RHRS trains assures that the heat removal capacity of the system is only partially lost if one train becomes inoperative. Two heat exchangers also allow maintenance of one exchanger while the other unit is in operation.

The RHRS heat exchangers are of the shell and U-tube type. Reactor coolant circulates through the tubes, while primary plant CCW circulates through the shell. The tubes are welded to the tube sheet to prevent leakage of reactor coolant.

Temperature elements are located in the system upstream and downstream of each RHRS heat exchanger. The temperatures are recorded on the main control board by dual pen recorders.

Residual Heat Removal System Valves

Manual operated valves and motor-operated gate valves have backseats to facilitate repacking and to limit steam leakage when the valves are open. Leakage connections are provided where required by valve size and fluid conditions.

5.4.7.2.3 System Operation

Reactor Startup

Generally, while at cold shutdown condition, decay heat from the reactor core is being removed by the RHRS. The number of pumps and heat exchangers in service depends upon the heat load at the time.

The following is a representative sequence of events to describe the startup of the reactor coolant system. The RCS is filled to a water level indicated in the pressurizer. Nitrogen gas is placed on the pressurizer and RCS pressure is raised to permit reactor coolant pump operation. A charging pump is in operation, seal water to the RCPs is established, RHRS is in service and letdown is by way of the RHRS to the VCT. During this time, the RHRS acts as an alternate letdown path. The MOVs downstream of the RHR heat exchangers leading to the letdown line of the CVCS are opened. The control valve in the line from the RHRS to the letdown line of the CVCS is manually adjusted in the control room to permit letdown flow. Failure of any one of the valves in the line from the RHRS to the CVCS has no safety implications, either during startup or cooldown.

The RCPs are intermittently operated and the reactor head is vented in sequence until all air is swept from the loops. RCS pressure is lowered and the head is vented. The primary plant tanks are purged with nitrogen to reduce the oxygen to within chemistry specifications. The pressurizer is filled to a water solid condition and the pressurizer heaters are energized to heat the pressurizer. When the pressurizer is heated to a prescribed temperature, the steam bubble is formed in the pressurizer by manual control of letdown. Indication of steam bubble formation is provided in the control room by the damping out

of the RCS pressure fluctuations, and by pressurizer level indication. The RHRS is then isolated from the RCS and the system pressure is controlled by normal letdown and the pressurizer spray and pressurizer heaters.

Power Generation and Hot Standby Operation

During power generation and hot standby operation, the RHRS is isolated and not in service.

Reactor Cooldown (Normal)

Reactor cooldown is defined as the operation which brings the reactor from no-load temperature and pressure to cold conditions.

The initial phase of a normal reactor cooldown is accomplished by transferring heat from the RCS to the steam and power conversion system. Circulation of the reactor coolant is provided by the RCPs and heat removal is accomplished by using the steam generator and dumping steam to the condenser.

In conjunction with this portion of the cooldown, the reactor coolant is borated to the concentration required for cold shutdown and depressurized to a pressure permitting RHRS operation. Boration and makeup for the contraction of the RCS due to cooling are performed using the charging, letdown, and makeup control portions of the CVCS. The depressurization function is performed by initiating pressurizer spray from the discharge of the operating RCP.

When the reactor coolant temperature and pressure are reduced to approximately 350°F and 400 psig, within 4 hours after reactor shutdown, the second phase of cooldown starts with the RHRS being placed in operation.

Startup of the RHRS includes a warmup period during which time reactor coolant flow through the heat exchangers is limited to minimize thermal shock. The rate of heat removal from the reactor coolant is manually controlled by regulating the coolant flow through the residual heat exchangers. By adjusting the control valves downstream of the RHRS heat exchangers, the mixed mean temperature of the return flow is controlled. Coincident with the manual adjustment, each heat exchanger bypass valve is automatically regulated to give the required total flow.

The reactor cooldown rate is limited by RCS equipment cooling rates based on allowable stress limits, as well as the operating temperature limits of the primary plant CCWS. As the reactor coolant temperature decreases, the reactor coolant flow through the RHRS heat exchangers is increased by adjusting the control valve in each heat exchanger's tube side outlet line.

As cooldown continues, the pressurizer is either filled with water, and the RCS is operated in the water solid condition, or a nitrogen bubble is established.

At this stage, pressure control is accomplished by regulating the charging flow rate and the rate of letdown from the RHRS to the CVCS.

After the reactor coolant pressure is reduced and the temperature is 140°F or lower, the RCS may be opened for refueling or maintenance.

Cold Shutdown

It is expected that the systems normally used for cold shutdown will be available anytime the operator chooses to perform a reactor cooldown. However, to ensure that the plant can be taken to cold shutdown at any time, the cold shutdown design enables the RCS to be taken from no-load temperature and pressure to cold conditions with only onsite or offsite power available, and assuming the most limiting single failure.

Should portions of normal shutdown systems be unavailable, the operator should maintain the plant in hot standby condition while making the normal systems functional. Local manual actions could be performed where such are permitted by the prevailing environmental conditions. Appropriate procedures are provided for the use of backup systems contingent upon the inability to make normal systems available. The operator should use any of the normal systems that are available in combination with the backup systems. Backup provisions are to be made only upon the inability to make available the equipment normally used for the given function.

The cold shutdown design enables the operator to maintain the plant in hot standby for more than 4 hours. Since it is assumed that the RCPs are not available, circulation of the reactor coolant is provided by natural circulation with the reactor core as the heat source and the steam generators as the heat sink. Heat removal is accomplished via the steam line atmospheric dump valves (ADVs) and auxiliary feedwater system (AFWS).

The potential for voiding in the RCS during anticipated transients has been analyzed in accordance with NUREG-0737, Item II.K.2.17 (USNRC 1980) (Westinghouse 1981a and 1981b).

For the purpose of establishing conservative requirements for auxiliary feedwater capacity, it is assumed that the RCS is borated to cold shutdown concentration prior to cooling the RCS. The charging pumps are used to provide 4 weight percent boric acid from the boric acid tanks to the RCS. The borated water is delivered to the RCS cold legs via the high head safety injection lines. Reactor coolant pump seal injection is also maintained. To accommodate this addition to RCS inventory, continuous letdown is discharged from the reactor vessel head letdown line to the PRT.

Following boration to cold shutdown concentration, cooldown is accomplished by increasing the steam dump from the steam line ADVs. In conjunction with this portion of the cooldown, the charging pumps are used to deliver water to makeup for RCS inventory contraction due to cooling. Makeup is also provided for the RCS inventory discharged when the reactor vessel head letdown path is periodically cycled to provide head cooling. Upon approaching the end of this phase of cooldown, the RCS is depressurized by venting the pressurizer through use of the safety grade pressurizer PORVs.

To ensure that the accumulators do not repressurize the RCS, the accumulator discharge valves are closed prior to the RCS pressure dropping below the accumulator discharge pressure. Additionally, the accumulators are provided with redundant Class 1E solenoid operated valves to ensure that any accumulator may be vented, should it fail to be isolated from the RCS.

When the reactor coolant temperature and pressure are reduced to approximately 350°F and 400 psig, respectively. The second phase of cooldown starts with the RHRS being placed in operation.

As cooldown continues, the reactor vessel head vent line (used for letdown) is periodically opened to increase head cooling and to accommodate any additional input to the RCS, such as RCP seal injection. Should a single failure, such as that of a RHRS component or of an emergency power train (when only onsite power is available) limit operation to one of the RHR subsystems, the operator would open the series isolation valves in the suction of only the operable RHR subsystem. In this case, the operator would also ensure that the cross connect isolation valves between the subsystems are closed. Residual heat removal would continue under these conditions until the redundant subsystem could be made available.

Refueling

Upon initiation of refueling mode of operation, the RCS is drained to 6 inches below the reactor vessel flange. Prior to draining the RCS, administrative action must be taken. During drain down, the water level in the RCS must be monitored and throttling of flow is required to maintain adequate NPSH for the RHR pumps.

During refueling, the RHRS is maintained in service with the number of pumps and heat exchangers in operation as determined by the heat load and RHRP NPSH requirements.

Following refueling, the RHRPs are used to drain the refueling cavity to the top of the reactor vessel flange by pumping water from the RCS to the RWST.

5.4.7.2.4 Control

Each RHRP suction line is equipped with a relief valve sized to relieve the combined flow of two charging pumps at the relief valve set pressure. These relief valves also protect the RCS from inadvertent overpressurization during plant cooldown or startup. Each valve has a relief flow capacity of 900 gpm at a set pressure of the open permissive setpoint. An analysis has been conducted to confirm the capability of the RHRS relief valve to prevent overpressurization in the RHRS. All credible events were examined for their potential to overpressurize the RHRS. These events included normal operation conditions, infrequent transients, and abnormal occurrences. The analysis confirmed that one relief valve has the capability to keep the RHRS maximum pressure within code limits.

The fluid discharged by the suction side relief valves is collected in the PRT.

To provide isolation between the high pressure RCS and the lower pressure RHRS, the design of the RHRS includes two motor operated gate valves in series in each pump suction line and another motor operated gate valve in each discharge line. These valves are closed during normal operation and are only opened for RHR during a plant cooldown after the RCS pressure is reduced to the open permissive setpoint and the RCS temperature is reduced to approximately 350°F. During a plant start-up, the isolation valves are shut after drawing a bubble in the pressurizer and prior to increasing RCS pressure above 450 psig. These isolation valves are provided with both prevent-open and auto-closure interlocks which are designed to prevent possible exposure to the RHRS to normal RCS operating pressure.

The two inlet isolation valves in each RHR subsystem are separately and independently interlocked with pressure signals to prevent valve opening unless the RCS pressure is below approximately 360 psig.

The two inlet isolation valves in each RHR subsystem are also separately and independently interlocked with pressure signals to automatically shut if RCS pressure increases to approximately 700 psig during a plant startup. The RHR autoclosure interlock may be manually defeated during normal RHR system operation to increase the plant shutdown safety posture by reducing the potential for inadvertent RHR isolation valve closure and the subsequent loss of RHR cooling capability. Defeating the interlock can be implemented in place of the previous method of de-energizing the RHR isolation motor-operated valves because remote control of these valves will be retained from the control room to quickly mitigate any potential RHR system leaks during shutdown operation. The autoclosure interlock is manually returned to operation during normal RHR system shutdown. The purpose of the autoclosure interlock is to ensure that there is a double barrier between the Reactor Coolant System and the RHR when the plant is at normal operating conditions being hot and pressurized and not in the RHR cooling mode.

The use of two independently powered MOVs in each of the two inlet lines, along with two independent pressure interlock signals for each function, assures a design which meets applicable single failure criteria. Not only more than one single failure but also different failure mechanisms must be postulated to defeat the function of preventing possible exposure of the RHRS to normal RCS operating pressure. These protective interlock designs, in combination with plant operating procedures, provide diverse means of accomplishing the protective function.

The RHRS inlet isolation valves are provided with red-green position indicator lights on the main control board.

The motor operated isolation valve in each discharge line is interlocked with a pressure signal to prevent valve opening unless the RCS pressure is below approximately 360 psig, and to automatically close if the RCS pressure increases to approximately 700 psig. These two valves, one in each RHRS discharge line, are interlocked with different transmitters. Isolation of the low pressure RHRS from the high pressure RCS is also provided in the discharge line by a check valve which is located in the ECCS. The testing of this check valve is described in Section 6.3.4.2.

Section 7.6.2 further discusses the instrumentation and control features.

5.4.7.2.5 Applicable Codes and Classifications

The entire RHRS is designed as Safety Class 2 with the exception of the portions that form a part of the RCS pressure boundary which are designed as Safety Class 1. Component codes and classifications are given in Section 3.2.

5.4.7.2.6 System Reliability Considerations

General Design Criterion 34 requires that a system to remove residual heat be provided. The safety function of this system is to transfer fission product decay heat and other residual heat from the core at a rate sufficient to prevent fuel or pressure boundary design limits from being exceeded. Both NSSS and balance of plant (BOP) safety grade systems are provided in the plant design to perform this safety function. The NSSS systems which perform this function, for all plant conditions except a LOCA, are the RCS, RHRS, and steam generators. The BOP safety grade systems which perform this function, for all plant conditions except LOCA, are the AFWS, the steam generator safety valves, and the steam line ADVs, which operate in conjunction with the RCS and the steam generators, and the primary plant CCW and service water system, which operate in conjunction with the RHRS. For LOCA conditions, the safety grade systems which perform the function of removing residual heat from the reactor core is the ECCS, AFWS, and steam line ADVs which are described in Sections 6.3 and 10.4.9.

The AFWS, along with the steam generator safety valves and steam line ADVs, provides a completely separate, independent, and diverse means of performing the safety function of removing residual heat, which is normally performed by the RHRS when RCS temperature is less than 350°F. The AFWS is capable of performing this function for an extended period of time following plant shutdown.

The RHRS is provided with two RHRPs and two RHR heat exchangers arranged in separate and independent flow paths. To assure

reliability, each RHRP is connected to a different Class 1E bus. Each RHR train is isolated from the RCS on the suction side by two MOVs in series. Each MOV receives power via a separate motor control center (MCC) and the two valves in series in each train receive their power from a different Class 1E bus. The suction isolation valve in each train not powered by the same vital bus as powers in the RHRP in that train has the capability for transferring its power supply to the opposite, functioning vital bus. Each suction isolation valve is also interlocked to prevent exposure of the RHRS to the normal operating pressure of the RCS (Section 5.4.7.2.4).

The RHRS operation for normal conditions and for major failures is accomplished completely from the control room. The redundancy in the RHRS design provides the system with the capability to maintain its cooling function even with major single failures, such as failure of an RHRP, valve, or heat exchanger since the redundant train can be used for continued heat removal.

Although such major system failures are within the system design basis, there are other less significant failures which can prevent opening of the RHRS suction isolation valves from the control room. Since these failures are of a minor nature, improbable to occur, and easily corrected outside the control room, with ample time to do so, they have been realistically excluded from the engineering design basis. Such failures are not likely to occur during the limited time period in which they can have any effect (that is, when opening the suction isolation valves to initiate RHRS operation); however, even if they should occur, they have no adverse safety impact and can be readily corrected. In such a situation, the AFWS and steam generator PORVs can be used to perform the safety function of removing residual heat and in fact can be used to continue the plant cooldown below 350°, until RHRS is made available.

One failure of this type is a failure in the interlock circuitry which is designed to prevent exposure of the RHRS to the normal operating pressure of the RCS (Section 5.4.7.2.4). In the event of such a failure, RHRS operation can be initiated by defeating the failed interlock through corrective action at the solid state protection system cabinet or at the individual affected MCCs.

Another type of failure which can prevent opening the RHRS suction isolation valves from the control room is a failure of an electrical power train. Such a failure is extremely unlikely to occur during the few minutes out of a year's operating time during which it can have any consequence. If such an unlikely event should occur, several alternatives are available. The most realistic approach would be to obtain restoration of offsite power, which can be expected to occur in less than 1/2 hour. Other alternatives are to restore the emergency diesel generator to operation or to transfer the power source to a suction valve (in the functioning RHRP train) from the failed electrical bus to the functioning bus.

The only impact of either of the preceding types of failures is some delay in initiating RHRS operation, while action is taken to open the RHRS suction isolation valves. This delay has no adverse safety impact because of the capability of the AFWS and steam line ADVs to continue to remove residual heat, and in fact to continue plant cooldown.

5.4.7.2.7 Manual Actions

The RHRS is designed to be fully operable from the control room for normal operation. Manual operations required of the operator are: 1) opening the suction and discharge isolation valves, 2) positioning the flow control valves downstream of the RHR heat exchangers, and 3) starting the RHRPs.

Manual actions required outside the control room, under conditions of single failure, are discussed in Section 5.4.7.2.6.

An emergency shutdown panel, located outside the control room, has been provided as an alternate means of shutdown in the event of control room inhabitability. An alternate shutdown panel (ASP), located in the auxiliary building, has been provided as an alternate means of shutdown in the event of an exposure fire. Section 7.4 provides additional discussion of these panels.

5.4.7.3 Performance Evaluation

The performance of the RHRS in reducing reactor coolant temperature is evaluated through the use of heat balance calculations on the RCS, and the primary plant CCWS at stepwise intervals following the initiation of RHRS operation. Heat removal through the RHRS and CCW heat exchangers is calculated at each interval by use of standard water-to-water heat exchanger performance correlations; the resultant fluid temperatures for the RHR and CCW are calculated and used as input to the next interval's heat balance calculation.

Assumptions utilized in the series of heat balance calculations describing plant RHRS cooldown are as follows:

1. Residual heat removal system operation can be initiated within 4 hours after reactor shutdown.

2. Residual heat removal system operation begins at a reactor coolant temperature of 350°F.

3. Thermal equilibrium is maintained throughout the RCS during the cooldown.

4. Primary plant CCW heat exchanger outlet temperature during cooldown is limited to a maximum of 120°F.

Cooldown curves calculated using this method are provided for the case of all RHRS components operable and for the case of a single train RHRS cooldown (Figure 5.4-6).

5.4.7.4 Pre-operational Testing

Pre-operational testing of the RHRS is addressed in Chapter 14.

5.4.8 Reactor Water Cleanup System

This section is not applicable to BVPS-2.

5.4.9 Main Steam Line and Feedwater Piping

Main steam lines and feedwater piping are discussed in the MSS (Section 10.3) and the feed and condensate systems (Section 10.4.7).

5.4.10 Pressurizer

5.4.10.1 Design Bases

The general configuration of the pressurizer is shown on Figure 5.1-1. The design data of the pressurizer are given in Table 5.4-12. Codes and material requirements are provided in Section 5.2.

The pressurizer provides a point in the RCS where liquid and vapor can be maintained in equilibrium under saturated conditions for pressure control purposes during both steady state operation and transients.

5.4.10.1.1 Pressurizer Surge Line

The surge line is sized to minimize the pressure drop between the RCS and the pressurizer with maximum allowable discharge flow from the safety valves.

The surge line and the thermal sleeve at the pressurizer are designed to withstand the thermal stresses which occur during operation, resulting from volume surges of relatively hotter or colder water which may occur during operation.

The pressurizer surge line nozzle diameter is given in Table 5.4-12.

5.4.10.1.2 Pressurizer

The volume of the pressurizer is equal to, or greater than, the minimum volume of steam, water, or total of the two which satisfies all of the following requirements:

1. The combined saturated water volume and steam expansion volume is sufficient to provide the desired pressure response to system volume changes.

2. The water volume is sufficient to prevent the heaters from being uncovered during a step load increase of 10 percent at full power.

3. The steam volume is large enough to accommodate the surge resulting from 95-percent reduction of full load with automatic reactor control and 85-percent steam dump without the water level reaching the high level reactor trip point.

4. The steam volume is large enough to prevent water relief through the safety valves following a loss of load with the high water level initiating a reactor trip, without reactor control or steam dump.

5. The pressurizer will not empty following reactor trip and turbine trip.

6. The emergency core cooling signal is not activated during reactor trip and turbine trip.

5.4.10.2 Design Description

5.4.10.2.1 Pressurizer Surge Line

The pressurizer surge line connects the pressurizer to one reactor hot leg enabling continuous coolant volume pressure adjustments between the RCS and the pressurizer.

5.4.10.2.2 Pressurizer

The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads constructed of low carbon steel, with austenitic stainless steel cladding on all internal surfaces exposed to the reactor coolant. A stainless steel liner or tube is used in lieu of cladding on the spray nozzle.

The surge line nozzle is located in the bottom of the pressurizer. The electric heaters are located in the lower portion of the pressurizer, and are removable for maintenance or replacement.

Thermal sleeves are provided to minimize thermal stresses in the surge spray line nozzles of the pressurizer. A retaining screen is located above the surge line nozzle to prevent any foreign matter from entering the RCS. Baffles in the lower section of the pressurizer prevent an insurge of cold water from flowing directly to the steam/water interface and assist in mixing.

The spray line nozzle, relief, and safety valve connections are located in the top head of the vessel. Spray flow is modulated by automatically controlled air operated valves or operated manually by a switch in the control room.

A small continuous spray flow is provided through a manual bypass valve around the power operated spray valves to assure that the pressurizer liquid is homogeneous with the coolant and to prevent excessive cooling of the spray piping.

During an outsurge from the pressurizer, flashing of water to steam and generating of steam by automatic actuation of the heaters keep the pressure above the minimum allowable limit. During an insurge from the RCS, the spray system, which is fed from two cold legs, condenses steam in the vessel to prevent the pressurizer pressure from reaching the set point of the power operated relief valves for normal design transients. Heaters are energized on high water level during insurge to heat the subcooled surge water that enters the pressurizer from the reactor coolant loop.

Material specifications are provided in Table 5.2-2 for the pressurizer, pressurizer relief tank, and the surge line. Design transients for the components of the RCS are discussed in Section 3.9N.1. Additional details on the pressurizer design cycle analysis are given in Section 5.4.10.3.5.

Pressurizer Instrumentation

Chapter 7.0 discusses the instrumentation associated with pressurizer pressure, level, and temperature.

Spray Line Temperatures

Temperatures in the spray lines from the cold legs of two loops are measured and indicated. Alarms from these signals are actuated to warn the operator of low spray water temperature which may indicate insufficient flow in the spray lines.

Safety and Relief Valve Discharge Temperatures

Temperatures in the pressurizer safety valve discharge line and relief manifold, are measured and indicated. An increase in a discharge line temperature is an indication of leakage or relief through the associated valve.

5.4.10.3 Design Evaluation

5.4.10.3.1 System Pressure

Whenever a steam bubble is present within the pressurizer, the RCS pressure will be maintained by the pressurizer. Analyses indicate that proper control of pressure is maintained for the normal operating conditions.

A safety limit has been set to ensure that the RCS pressure does not exceed the maximum transient value allowed under the ASME Code, Section III, and thereby assure continued integrity of the RCS

components. The following evaluation of plant conditions during normal operation, indicate that this safety limit is not reached.

During startup and shutdown, the rate of temperature change in the RCS is controlled by the operator. Heatup rate is controlled by pump energy and by the pressurizer electrical heating capacity. This heatup rate takes into account the continuous spray flow provided to the pressurizer. When the reactor core is in cold shutdown, the heaters are de-energized.

When the pressurizer is filled with water, that is, during initial system heatup, and near the end of the second phase of plant cooldown, RCS pressure is maintained by the letdown flow rate via the RHRs.

5.4.10.3.2 Pressurizer Performance

The normal operating water volume at full load conditions is a percentage of the internal vessel volume. Under part load conditions, the water volume in the vessel is reduced for proportional reductions in plant load to accommodate the accompanying thermal contraction of the reactor coolant. The various plant operating transients are analyzed and the design pressure is not exceeded with the pressurizer design parameters as given in Table 5.4-12.

5.4.10.3.3 Pressure Set Points

The RCS design and operating pressure together with the safety, power relief and pressurizer spray valves set points, and the protection system pressure set points are listed in Table 5.4-13. The design pressure allows for operating transient pressure changes. The selected design margin considers core thermal lag, coolant transport times and pressure drops, instrumentation and control response characteristics, and system relief valve characteristics.

5.4.10.3.4 Pressurizer Spray

Two separate, automatically controlled spray valves with remote manual overrides are used to initiate pressurizer spray. In parallel with each spray valve is a manual throttle valve which permits a small continuous flow through both spray lines to reduce thermal stresses and thermal shock when the spray valves open, and to help maintain uniform water chemistry and temperature in the pressurizer. Temperature sensors with low alarms are provided in each spray line to alert the operator to insufficient bypass flow. The layout of the common spray line piping routed to the pressurizer forms a water seal which prevents the steam buildup back to the control valves. The spray rate is selected to prevent the pressurizer pressure from reaching the operating set point of the power relief valves during a step reduction in power level of 10 percent of full load.

The pressurizer spray lines and valves are large enough to provide adequate spray using as the driving force the differential pressure between the surge line connection in the hot leg and the spray line connection in the cold leg. The spray line inlet connections extend into the cold leg piping in the form of a scoop in order to utilize the velocity head of the reactor coolant loop flow to add to the spray driving force. The spray valves and spray line connections are arranged so that the spray will operate when one RCP is not operating. The line may also be used to assist in equalizing the boron concentration between the reactor coolant loops and the pressurizer.

A flow path from the CVCS to the pressurizer spray line is also provided. This additional facility provides auxiliary spray to the vapor space of the pressurizer during cooldown when the RCPS are not operating. The thermal sleeve on the pressurizer spray nozzle is designed to withstand the thermal stresses resulting from the introduction of cold spray water.

5.4.10.3.5 Pressurizer Design Analysis

The occurrences for pressurizer design cycle analysis are defined as follows:

1. The temperature in the pressurizer vessel is always, for design purposes, assumed equal to the saturation temperature for the existing RCS pressure, except in the pressurizer steam space subsequent to a pressure increase. In this case the temperature of the steam space will exceed the saturation temperature since an isentropic compression of the steam is assumed.

   The only exception of the above occurs when the pressurizer is filled water solid during plant startup and cooldown.

2. The temperature shock on the spray nozzle is assumed to equal the temperature of the nozzle minus the minimum spray line temperature and the temperature shock on the surge nozzle is assumed to equal the pressurizer water space temperature minus the hot leg temperature.

3. Pressurizer spray is assumed to be initiated instantaneously to its design value as soon as the RCS pressure increases 40 psi above the nominal operating pressure. Spray is assumed to be terminated as soon as the RCS pressure falls below the operating pressure plus 40 psi unless otherwise noted.

4. Unless otherwise noted, pressurizer spray is assumed to be initiated once per occurrence of each transient condition. The pressurizer surge nozzle is also assumed to be subject

to one temperature transient per transient condition, unless otherwise noted.

5. Each upset condition transient results in a reactor trip. At the end of each transient, except the faulted conditions, the RCS is assumed to return to no-load conditions consistent with the pressure and temperature changes.

   For design purposes, the following assumptions are made with respect to Condition III (Emergency Conditions) and Condition IV (Faulted Conditions) transients (Section 15.0.1).

   The plant eventually reaches cold shutdown conditions after all Condition IV transients and after the following Condition III transients: 1) small LOCA, and 2) small steam line break accident.

   For the other Condition III transients, the plant goes to hot shutdown until the condition of the plant is determined. It is then brought either to no-load conditions or to cold shutdown conditions, with pressure and temperature changes controlled within allowable limits.

6. Temperature changes occurring as a result of pressurizer spray are assumed to be instantaneous. Temperature changes occurring on the surge nozzle are also assumed to be instantaneous.

7. Whenever spray is initiated in the pressurizer, the pressurizer water level is assumed to be at the no-load level.

5.4.10.4 Tests and Inspections

The pressurizer is designed and constructed in accordance with the ASME Code, Section III.

To implement the requirements of the ASME Code, Section XI, the following welds are designed and constructed to present a smooth transition surface between the parent metal and the weld metal. The path is ground smooth for ultrasonic inspection.

1. Support skirt to the pressurizer lower head.

2. Surge nozzle to the lower head.

3. Nozzle to safe end attachment welds.

4. All girth and longitudinal full penetration welds.

5. Manway attachment welds.

6. Safety, relief, and spray nozzles to the upper head.

The liner within the safe end nozzle region extends beyond the weld region to maintain a uniform geometry for ultrasonic inspection.

Peripheral support rings are furnished for the removable insulation modules.

The pressurizer NDE program is given in Table 5.4-14.

5.4.11 Pressurizer Relief Discharge System

The pressurizer relief discharge system collects, cools, and directs, for processing, the steam and water discharged from various safety and relief valves (SRVs) in the containment. The system consists of the pressurizer relief tank, the SRV discharge piping, the relief tank internal spray header and associated piping, and the tank nitrogen supply, vent to containment and drain to the boron recovery system, via the PDTT inside containment (Section 9.3.3).

5.4.11.1 Design Basis

Codes and materials of the PRT and associated piping are given in Section 5.2. Design data for the tank are given in Table 5.4-15.

The system design is based on the requirement to absorb a discharge of steam equivalent to 100 percent of the full power pressurizer steam volume. The steam volume requirement is approximately that which would be experienced if the plant were to suffer a complete loss of a load accompanied by a turbine trip but without the resulting reactor trip. A delayed reactor trip is considered in the design basis.

The minimum volume of water in the PRT is determined by the energy content of the steam to be condensed and cooled, by the assumed initial temperature of the water, and by the desired final temperature of the water volume. The initial water temperature is assumed to be 120°F, which corresponds to the expected design maximum containment temperature for normal conditions. Provision is made to permit cooling of the tank should the water temperature rise above 120°F during BVPS-2 operation. The design final temperature is 200°F, which allows the contents of the tank to be drained directly to the PDTT.

The vessel saddle supports and anchor bolt arrangement are designed to withstand the loading resulting from a combination of nozzle loadings acting simultaneously with the vessel seismic and static loadings.

5.4.11.2 System Description

The steam and water discharged from the various SRVs inside containment is routed to the PRT if the discharged fluid is of reactor grade quality. Table 5.4-16 provides a list of valves discharging to the tank with references to the corresponding UFSAR figure.

The tank normally contains water and a predominantly nitrogen atmosphere. In order to obtain effective condensing and cooling of the discharged steam, the tank is installed horizontally with the steam discharged through a sparger pipe located near the tank bottom and under the water level. The sparger holes are designed to ensure a resultant steam velocity close to sonic.

The tank is also equipped with an internal spray and a drain which are used to cool the water following a discharge. Water is provided by the primary grade water system.

The nitrogen gas blanket is used to control the atmosphere in the tank and to allow room for the expansion of the original water plus the condensed steam discharge. The tank gas volume is calculated using a final pressure based on an arbitrary design pressure of 100 psig. The design discharge raises the worst-case initial conditions to 5 psig, a pressure low enough to prevent fatigue of the rupture disks. Provision is made to permit the gas in the tank to be periodically analyzed to monitor the concentration of hydrogen and/or oxygen.

The tank may be vented to the gaseous vent header and drained to the PDTT.

5.4.11.2.1 Pressurizer Relief Tank

The tank is a horizontal, cylindrical vessel with elliptical dished heads. The vessel is constructed of austenitic stainless steel and is overpressure protected in accordance with ASME Code Section VIII, Division 1, by means of two safety heads with stainless steel rupture discs.

A flanged nozzle is provided on the tank for the pressurizer discharge line connection to the sparger pipe. The tank is also equipped with an internal spray connected to a cold water inlet and a bottom drain, which are used to cool the tank following a discharge.

5.4.11.3 Safety Evaluation

The pressurizer relief discharge system does not constitute part of the RCPB per 10 CFR 50, (Section-50.2), since all of its components are downstream of the RCS SRVs. Thus, General Design Criteria 14 and 15 are not applicable. Furthermore, complete failure of the auxiliary systems serving the PRT will not impair the capability for safe shutdown.

The design of the system piping layout and piping restraints is consistent with Regulatory Guide 1.46. The SRV discharge piping is restrained to that integrity and operability of the valves are maintained in the event of a rupture. Regulatory Guide 1.67 is not applicable since the system is not an open discharge system.

The pressurizer relief discharge system is capable of handling the design discharge of steam without exceeding the design pressure and temperature of the PRT.

The volume of water in the PRT is capable of absorbing the heat from the assumed discharge maintaining the water temperature below 200°F. If a discharge exceeding the design basis should occur, the relief device on the tank would pass the discharge through the tank to the containment.

The rupture discs on the relief tank have a relief capacity equal to or greater than the combined capacity of pressurizer safety valves. The tank design pressure is twice the calculated pressure resulting from the design basis safety valve discharge described in Section 5.4.11.1. The tank and rupture discs holders are also designed for full vacuum to prevent tank collapse if the contents cool following a discharge without nitrogen being added.

The discharge piping from the pressurizer SRVs to the relief tank is sufficiently large to prevent backpressure at the safety valves from exceeding 20 percent of the set point pressure at full flow.

5.4.11.4 Instrumentation Requirements

The PRT pressure transmitter provides an indication of PRT pressure. An alarm is provided to indicate high tank pressure.

The PRT level transmitter supplies a signal for an indicator with high and low level alarms.

The temperature of the water in the PRT is indicated, and an alarm actuated by high temperature informs the operator that cooling of the tank contents is required.

5.4.11.5 Inspection and Testing Requirements

The system components are subject to nondestructive and hydrostatical testing during construction in accordance with Section VIII, Division 1 of the ASME Code.

During BVPS-2 operation, periodic visual inspections and maintenance are conducted on the system components according to normal industrial practice.

5.4.12 Valves

5.4.12.1 Design Bases

As noted in Section 5.2, all valves in lines connected to the RCS out to and including the second valve normally closed or capable of automatic or remote closure, larger than 3/4 inch, are ANS Safety Class 1, and ASME Boiler and Pressure Vessel Code, Section III, Code Class 1 valves. All 3/4-inch or smaller valves in lines connected to the RCS are Class 2 since the interface with the Class 1 piping is provided with suitable orificing for such valves. Design data for the RCS valves, except the loop stop valves, are given in Table 5.4-17.

For a check valve to qualify as part of the RCS, it must be located inside the containment system. Reliability tests and inspections for these valves are discussed in Section 6.3.4.2.

To ensure that the valves will meet the design objectives, the materials used in construction are chosen such that corrosion/erosion is minimized, and compatibility with the environment is maintained. Leakage is minimized to the extent practicable by the design.

5.4.12.2 Design Description

All valves in the RCS are constructed primarily of stainless steel.

All manually operated valves and MOVs of the RCS which are 3 inches and larger are provided with stuffing boxes and intermediate stem leakoff connections. All throttling control valves are provided with stuffing boxes and with stem leakoff connections. In general, RCS leakoff connections are piped to a closed system. Leakage to the atmosphere is essentially zero for these valves.

All check valves which contain radioactive fluid are stainless steel and do not have body penetrations other than the inlet, outlet, and bonnet.

The reactor coolant loop stop valves are remotely controlled motor operated gate valves which permit any loop to be isolated from the reactor vessel. One valve is installed on each hot leg and one on each cold leg. Each set of packing shall be capable of being tightened independently of the other sets of packing.

License Amendment 78 revised the method for isolated loop startup. Therefore, the interlock system for opening a cold leg loop stop valve described below may be procedurally bypassed.

To ensure against an accidental startup of an unborated and/or cold isolated loop, an additional valve interlock system is provided which meets IEEE-279. There is a relief line and bypass around the cold leg isolation valve. The additional interlocks ensure flow from the isolated loop to the remainder of the RCS takes place through the relief line valve (after system pressure is equalized through the loop drain header and the hot leg isolation valve is opened) for a period of over 90 minutes before the cold leg loop stop valve is opened. The flow through the relief line is low (approximately 200 to 300 gpm) so that the temperature and boron concentration are brought to equilibrium with the remainder of the system at a relatively slow rate. The valve temperature relief line flow interlock:

1. Prevents opening of a hot leg isolation valve unless the cold leg loop stop valve is closed.

2. Prevents starting a RCP unless:

    a. The cold leg loop stop valve is closed and the loop bypass valve is open.

    b. Both the hot leg loop stop valve and cold leg loop stop valve are open.

3. Prevents opening of a cold leg loop stop valve unless:

    a. The hot leg loop stop valve has been opened for a specified time.

    b. The loop bypass valve has been opened a specified time.

    c. Flow has existed through the relief line for a specified time.

    d. The cold leg temperature is within 20°F of the highest cold leg temperature in other loops and the hot leg temperature is within 20°F of the highest hot leg temperature in the other loops.

The parameters of each reactor coolant loop stop valve are shown in Table 5.4-18. Codes and material requirements are provided in Section 5.2.

5.4.12.3 Design Evaluation

The design requirements for Code Class 1 valves, as discussed in Section 5.2, limit the stresses to levels which ensure structural integrity. In addition, the testing programs described in Section 3.9N.3 demonstrate the ability of the valves to operate as required during anticipated and postulated plant conditions.

Reactor coolant chemistry parameters are specified in the design specifications to assure the compatibility of valve construction materials with the reactor coolant. To ensure that the reactor coolant continues to meet these parameters, the chemical composition of the coolant will be analyzed periodically.

The above requirements and procedures, coupled with the previously described design features for minimizing leakage, ensure that the valves will perform their intended functions as required during plant operation.

5.4.12.4 Tests and Inspections

The tests and inspections discussed in Section 3.9 are performed to ensure the operability of active valves. Tests and inspections performed on ECCS valves are discussed in Section 6.3.

There are no full penetration welds within valve body walls. Valves are accessible for disassembly and internal visual inspection to the extent practical. Plant layout configurations optimize accessibility for in-service inspection. The valve NDE program is given in Table 5.4-19. In-service inspection is discussed in Section 5.2.4.

5.4.13 Safety and Relief Valves

5.4.13.1 Design Bases

The combined capacity of the pressurizer safety valves is designed to accommodate the maximum surge resulting from a complete loss of load. This objective is met without reactor trip or any operator action by the opening of the steam generator safety valves when steam pressure reaches the steam side safety setting.

The pressurizer PORVs are designed to limit pressurizer pressure to a value below the fixed high pressure reactor trip set point. They are designed to fail to the closed position on power loss.

The pressurizer PORVs are not required to open in order to prevent the overpressurization of the RCS. The pressurizer safety valves, by themselves, are sized to relieve enough steam to prevent an

overpressurization of the primary system. Therefore, the failure of the PORVs to open will result in higher reactor coolant pressures, but will not cause any overpressurization problems. The opening of the PORVs is a conservative assumption for the departure from DNB limited transients by tending to keep the primary system pressure down.

5.4.13.2 Design Description

The pressurizer safety valves are enclosed pop type. The valves are spring loaded, open by direct fluid pressure action, and have back pressure compensation features.

The 6-inch pipe connecting each pressurizer nozzle to its code safety valve is shaped in the form of a loop seal. Condensate resulting from normal heat losses accumulates in the loop. This water prevents any leakage of hydrogen gas or steam through the safety valve seats. If the pressurizer pressure exceeds the set pressure of the safety valves, they will start to lift discharging the water from the loop seal.

The pressurizer PORVs are electro-solenoid actuated valves which respond to a signal from a pressure sensing system or to manual control. Remotely operated stop valves are provided to isolate the PORVs if excessive leakage develops.

Temperatures in the pressurizer safety valves discharge lines and relief valve discharge manifold are measured and indicated. An increase in a discharge line temperature is an indication of leakage through the associated valve.

The PORVs provide a safety grade means for RCS depressurization to achieve cold shutdown. Section 5.4.7 discusses the use of these valves in this function.

Design parameters for the pressurizer safety valves and pressurizer PORVs are given in Table 5.4-20.

5.4.13.3 Design Evaluation

The pressurizer safety valves prevent RCS pressure from exceeding 110 percent of system design pressure, in compliance with the ASME Boiler and Pressure Vessel Code, Section III.

The pressurizer PORVs prevent actuation of the fixed reactor high-pressure trip for all design transients up to and including the design step load decreases with steam dump. The PORVs also limit undesirable opening of the spring-loaded safety valves.

The PORVs also provide a safety grade means of venting the pressurizer and, consequently, meet the intent of NUREG-0737, Item II.B.1 (USNRC 1980).

5.4.13.4 Tests and Inspections

All SRVs are subjected to hydrostatic tests, seat leakage tests, operational tests, and inspections as required. For safety valves that are required to function during a faulted condition, additional tests are performed. These tests are described in Section 3.9.

There are no full penetration welds within the valve body walls. Valves are accessible for disassembly and internal visual inspection.

Valves and piping configurations similar to those at BVPS-2 have been tested within the Electric Power Research Institute (EPRI) safety and relief valve test program. This program was conducted in response to NUREG-0737, Item II.D.1 (USNRC 1980). The results of the EPRI test program demonstrate the acceptability of the BVPS-2 design as described below.

The Crosby safety valves (6M16) and Garrett (Crosby) PORVs (3 in. x 6 in.) currently used at BVPS-2 are enveloped by those in the EPRI test. In addition, the fluid conditions and valve opening times used in calculating the flow transient loads for BVPS-2 were derived from the EPRI test program. The EPRI test conditions envelope the BVPS-2 plant-specific design conditions for both anticipated operational occurrences and accident conditions, and the piping and pipe supports are designed to withstand the resulting calculated loads in accordance with the applicable code requirements. The differences between the EPRI generic test loop piping and the BVPS-2 piping are accounted for by analyses using SWEC computer programs which have been benchmarked against the EPRI test results as described in Appendix 3A. The above analyses, supported by EPRI test results, demonstrate the functionability of the valves and the system's ability to withstand the imposed loadings from expected flow conditions.

5.4.14 Component Supports

The RCS component supports are part of a safety system that permits movement to accommodate thermal expansion of the reactor coolant piping during normal plant operation and provides restraint to the RCS components during accident conditions.

5.4.14.1 Design and Fabrication Bases

The component supports for the steam generators, the RCPS, the reactor vessel, and the pressurizer are designed to maintain structural integrity of the RCS during both normal and accident conditions. The design criteria for these component supports consider the effects of normal operating, seismic, and pipe rupture loading. The pipe rupture loads are based on postulated breaks in the main steam and feedwater lines, which affect the steam generator/support, and the spray and safety relief lines, which affect the pressurizer/support.

The load combinations and stress limits for the various conditions of design are listed in Table 5.4-21. The design criteria presented in Table 5.4-21 were developed using the AISC Manual of Steel Construction and the ASME Code, Section III, Subsection NF, as guidelines. Strict adherence to Subsection NF is not required for the component support systems described herein, because Subsection NF was not in effect at the time the various components of the support systems were developed.

At the time of purchase order placement for the reactor vessel structural support (RVSS), an appropriate code for fabrication did not exist. Therefore, the purchase specification for the RVSS required the fabrication to utilize the ASME VIII, Division I as guidance, with no code stamp required. Specifically, the areas of ASME VIII, Division I used in the fabrication of the RVSS include the following:

1. All welding was in accordance with Subsection UW,

2. Heat treatment-stress relieving was in accordance with Subsection UCS-56, and

3. Nondestructive testing was in accordance with Subsection UW-51, Appendix VIII and Appendix U.

Any deviations to the subsections of ASME VIII, Division I used as guidance, are identified in the final specifications for the RVSS.

5.4.14.2 Description of the Component Supports

The component supports are designed utilizing steel forgings and weldments fabricated from plates and structural steel shapes. In addition, hydraulic snubbers and rigid struts provide lateral restraint to the steam generator under dynamic load conditions, while allowing unrestrained thermal movement during normal plant operation.

5.4.14.2.1 Reactor Vessel Structural Support

The RVSS is a cylindrical, skirt-supported, double-walled structure designed to transfer loadings to the reinforced concrete mat of the containment structure and to the surrounding primary shield wall; it is fabricated of SA-516, Gr-70 plate. This component support is designed to restrain vertical, lateral, and rotational movement of the reactor vessel while permitting thermal expansion/contraction of

the reactor vessel during plant operation. The reactor vessel is set on leveling devices between each of the six RPV loop nozzle pads and the top of the support structure. This support is also designed to provide neutron shielding and thermal protection to the surrounding structure by means of a water-filled annular section, as well as to house and cool the ex-core neutron detectors. The RVSS is shown on Figure 5.4-10.

The reactor vessel support/leveling device, fabricated with material in compliance with the ASTM A-668-72 Type K material specification, is shown on Figure 5.4-11. The triple wedge shape device is positioned (without mechanical attachment) between each of the six reactor vessel nozzle pads and a

lubricated plate which is fastened to the top surface of the reactor vessel structural support. The functional requirement of the RPV support/leveling device is to provide vertical adjustment at each RPV nozzle restraint pad during installation of the reactor vessel. Each support/leveling device has a screw assembly to produce relative horizontal translation of the wedge shaped plates, which results in a limited vertical adjustment of the reactor vessel during installation. During all plant conditions, this support system is designed to transfer only vertically downward (compression) loads from the reactor vessel nozzle pads to the reactor vessel structural support. Upward loads are reacted by gib keys (Figure 5.4-11).

5.4.14.2.2 Steam Generator and Reactor Coolant Pump Supports

The steam generator and RCP supports are shown on Figures 5.4-12 and 5.4-13. The steam generator support system consists of an upper support ring and a lower support frame. The upper support ring transmits horizontal forces from the steam generator through four tangential load trains to the reinforced-concrete charging floor. Two tangential load trains are equipped with hydraulic snubbing cylinders which permit motion of the steam generator due to thermal expansion of the RCS. Vertical steam generator thermal motions are accommodated by the upper support assembly. The hydraulic cylinders are designed to lock and resist dynamic forces which result from seismic and/or pipe rupture conditions. The other two tangential load trains are equipped with rigid struts. The lower steam generator support frame is a weldment fabricated from structural steel shapes and plates. The support frame slides on lubricated bearing plates located under each corner column to permit radial thermal expansion of the RCS. The four corner columns transmit vertical forces from the steam generator to the cubicle floor. The support frame has large shear blocks on two sides which fit into embedments in the cubicle floor to guide the lower support frame along a direction radial to the reactor and transmit forces perpendicular to this motion into embedments in the cubicle floor.

The RCP is mounted within a frame weldment, fabricated from structural steel shapes and plates, supported above the cubicle floor by three pin-ended columns which provide vertical support while allowing free movement in the horizontal plane.

High-strength benched and tempered alloy steels (ASME A237, A540, A563, A514, A668, A519, A579 or equivalent material) are used for attachments to the steam generator and RCP support weldments, upper support rings, hydraulic snubbing assemblies, rigid struts, and pump support columns. The steam generator and RCP frame support weldments are fabricated from A-36 or equivalent fine grain, normalized and fully silicon-killed structural steel plates and

shapes, with the exception of thick forgings (snuffer mounting plates) which are fabricated from A-105 or equivalent material and welded to the supports.

5.4.14.2.3 Pressurizer Support

The pressurizer is supported by an integral, flanged skirt bolted to a welded ring girder. The ring girder and vessel are suspended from the charging floor by four hanger columns (Figure 5.4-14). Two brackets welded to the ring girder are attached to the wall through slotted holes which restrain all motions except vertical translation. In addition, integral lugs on the pressurizer fit into striker plate assemblies attached to embedments in the charging floor close to the center of gravity of the vessel. The striker plate assemblies permit the pressure vessel to expand vertically and radially but restrain any horizontal centerline displacements and rotations about the vertical axis of the vessel. The support is fabricated from 5A-516, Gr-70 plate SA-543 plate, SA-105 forging, SA-106, Gr B pipe, SA-36 plate, and SA-540, and SA-193, and SA-194 bolting materials.

5.4.14.3 Evaluation

5.4.14.3.1 Reactor Coolant System Component Supports - Loads Evaluation

The RCS is analyzed for the effects of normal operating, seismic OBE and SSE, and pipe rupture loads, as noted in Section 5.4.14.1 The loads from these analyses are combined for each component support according to Table 5.4-21 and a detailed stress analysis of each support is performed utilizing these combined loads. The stress evaluation of the supports is described in Section 5.4.14.3.2. In addition, combined loads at the concrete-component support and component-component support interfaces are defined for the structural and component (Westinghouse) design analyses as described later in this section.

The analysis of the RCS supports is performed using two basic sets of mathematical models. One set consists of idealizations of the surge line and the pressurizer, including its supports. The other consists of idealizations of the remainder of the RCS (steam generator, RCP, RPV, including their support systems, and the primary loop piping).

5.4.14.3.1.1 Steam Generator, Reactor Coolant Pump, and Reactor Pressure Vessel Supports Load Evaluation

The loads considered in the analysis of the supports are normal operating, seismic (OBE and SSE), and pipe rupture loads, as noted in Section 5.4.14.1. Pipe rupture includes the effects of the following:

1. The blowdown forces in the steam generator main steam and feedwater lines

2. A fluid jet impinging on the supports or components as applicable.

Static and dynamic analyses are performed to determine loads and stresses in the support structures and to obtain structural and NSSS interface loads for seismic and pipe rupture events. Each of these analyses is described in detail as follows:

Seismic Analysis

A mathematical model of the three loops (Figure 5.4-19) is used in the seismic analysis. The model includes the masses and stiffnesses representing the shield and crane walls, as well as the RCS components and their supports. The steam generator and RCP support base points are connected to the representation of the shield and crane walls allowing the model to have only one anchor point - a node at the top of the mat.

Natural frequencies and characteristic mode shapes are calculated for the undamped multi-degree-of-freedom model using the STARDYNE computer code developed by Mechanics Research (Section 3A.2). Two-dimensional (horizontal, vertical, and in-plane rotational components) acceleration time histories (OBE and SSE) at the top of the mat are applied to the model at the base node. A general discussion of the methods and requirements of seismic analyses is provided in Section 3.7. The normal mode method is used to obtain the time history response of the model to the applied forcing functions.

Since the steam generator and RCP supports are represented in the multi-loop model by stiffness matrices, results of the dynamic analysis are not utilized directly. Instead, displacements and rotations at times of peak response of the support components are statically applied to a detailed model of the steam generator and RCP supports to obtain internal loads and stresses, loads on the equipment support pads, and loads on the embedments at the base of each support. The model used for this evaluation is shown on Figure 5.4-20. The effects of the static displacements were determined using the STRUDL II computer code (Section 3A.2). The locations of the steam generator and RCP support reinforced concrete interface points are shown on Figure 5.4-21.

Pipe Rupture Analysis

The response of the steam generator and RCP support systems is determined for a terminal end break at the containment penetration or at the steam generator nozzle in the main steam and feedwater lines as shown on Figures 5.4-27 and 5.4-28. The break locations in the main steam and feedwater lines are determined according to the criteria presented in Section 3.6B.2.

In addition, a break at the welded connection of the primary loop cold leg and the pressurizer spray line is determined to be the governing case among all RCL lines not exempted by the LBB program (Section 3.6B.2.1).

It is assumed that the RPV support components are not governed by any of these breaks. Thus, the response of the RPV and its supports is not determined and the response of the steam generator and RCP supports is determined from a linear, elastic, modal analysis using the STARDYNE DYNRE1 computer code and a single loop model (Figure 5.4-24). Time history forcing functions, determined as described in Section 3.6B.2, are applied to the appropriate locations to perform the analysis.

Since the steam generator and RCP supports are represented by stiffness matrices in all of the models used in the preceding analyses, the results of the dynamic analyses are not utilized directly to obtain stresses and interface loads for the support frames. Stresses in the support members and interface loads are obtained in the same manner for all breaks, as described previously for the seismic analysis.

The primary loop equipment (i.e., SG, RCP and RPV) supports were originally designed for pressurization of the reactor cavity and the SG-RCP cubicles due to breaks in the primary loop piping. The pressurization effects on the supports due to breaks in the primary loop piping are more severe than those due to breaks in the main steam, pressurizer spray, and feedwater lines. Consequently, an evaluation of the pressurization effects due to these breaks is not required.

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The jet impingement load locations, orientations, and magnitudes are determined as described in Section 3.6B.2. The impingement effects on the steam generator and RCP support systems are determined by statically applying the jet impingement loads to the particular component affected.

The peak seismic and pipe rupture loads are combined by the square root sum of squares (SRSS) technique to obtain faulted condition loads and/or stresses for all supports. Tables 5.4-23, 5.4-24, and 5.4-26 and Figures 5.4-32 and 5.4-46 represent results prepared by the SRSS technique.

The normal operating condition and faulted condition loads at the concrete interfaces for the steam generator and RCP supports are provided in Tables 5.4-23 and 5.4-24. The corresponding loads at the NSSS component interfaces are provided on Figure 5.4-32.

The snubber assemblies are represented in the models used in the previously mentioned analyses by beam elements, pinned at both ends, with an equivalent axial stiffness. The output for the models used in the preceding analysis consists only of an axial load on the snubbers. A more detailed definition of the loads (bending moments and shear loads in addition to the axial load) in the steam generator support snubber assemblies is obtained by applying displacement time histories at the snubber assembly ends to models of the snubber assemblies and performing a linear dynamic analysis. A typical snubber model is shown on Figure 5.4-34. The displacement time histories applied to the detailed snubber models are obtained from the seismic and pipe rupture analyses described previously. Loads in the snubbers due to deadweight are also determined using the detailed snubber models. Loads due to jet impingement are determined assuming the snubber assemblies to be acting as simply supported beams.

5.4.14.3.1.2 Pressurizer Supports - Seismic and Pipe Rupture Analysis

The pressurizer support system is analyzed for the effects of normal operating, seismic, and pipe rupture loading due to breaks postulated in the spray and safety relief lines. The locations of the breaks considered and the location and type of restraints provided are described in Section 3.6B.2.5. The surge line breaks have been eliminated under the LBB program.

The seismic analysis uses the STARDYNE DYNRE4 computer code (Section 3A.2), and the model shown on Figure 5.4-38. An envelope of the seismic amplified response spectra at the elevations of the upper and lower supports is utilized. Loads and/or stresses determined from the application of a single horizontal seismic response spectra were summed on a absolute basis with those due to the application of a vertical seismic response spectra. The direction in which the single horizontal spectra was applied was the direction which produced the maximum load and/or stress level in the support system. The analysis is performed for an SSE event only and the results are used for an OBE event. The analysis is conservative since the response spectra for an SSE event (1 percent damping) envelops the response spectra for an OBE event (0.5 percent damping) at the elevations under consideration.

Pipe rupture, as it pertains to the pressurizer support system, includes the effects of the following:

1. The blowdown forces in the attached spray and safety relief piping, and

2. Asymmetric pressurization of the pressurizer cubicle.

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The pressurizer supports are represented by equivalent beam and plate elements in the model used in the analysis mentioned previously. The loads in the support components, due to the spray and relief line pipe breaks, are obtained by statically applying the blowdown forces to the model with an appropriate dynamic load factor.

The response of the pressurizer and its support system to asymmetric pressurization of the pressurizer cubicle is determined for breaks in the spray line and the safety and relief valve lines. A worst case break was considered for the spray line and a simultaneous break of all safety and relief valve lines was considered as a worst case for these lines. Pressure transients were determined for two spray line breaks: 1) a break at the spray line nozzle, and 2) a break in the spray line within Node 7 of the model shown on Figure 5.4-41. The latter break produced the more severe pressure differentials and was the controlling break for which the supports were analyzed. The pressure transients for these breaks were determined as described in Section 6.2.1.2. The results of the asymmetric pressurization analysis for each of these breaks were summed on a peak basis with those due to blowdown.

Pressure transients for the previously mentioned breaks are provided at the nodes shown on Figure 5.4-41 and are determined as described in Section 6.2.1.2. Force transients applied to the models are determined by applying the nodal pressure to the projected areas of the pressurizer within that node and transferring the resulting forces to nodes on the model of the pressurizer and its supports (Figure 5.4-38). A dynamic analysis is then performed using the STARDYNE computer code.

Peak loads due to normal operating, seismic, and pipe rupture conditions were combined absolutely according to Table 5.4-21. The resulting loads at the interfaces of the pressurizer support with the vessel and the concrete are provided on Figures 5.4-42 and 5.4-43. The loads on the pressurizer nozzles (spray and relief line) due to pipe rupture are provided on Figure 5.4-44.

5.4.14.3.2 Reactor Coolant System and Pressurizer Supports Stress Evaluation

A detailed stress analysis of the component supports is performed utilizing the loads generated by the analytical models and methods described previously. Each support component is determined to have adequate factors of safety for all design conditions. Factors of safety are provided only for those components of the support systems which have the lowest factors of safety.

The minimum factors of safety for the steam generator upper restraint design (including the lateral restraint) which is governed by pipe breaks in the main steam/feedwater lines, are identified in Table 5.4-26 and Figure 5.4-46. Since all the remaining design margins for the RPV (Table 5.4-25), steam generator/RCP (Table 5.4-26), and pressurizer support (Table 5.4-28) systems are based on the dynamic effects associated with the excluded primary coolant loop and surge line pipe breaks, the conservative design margins are listed for information only.

The internal loads distribution in the steam generator upper support ring is determined using the STRUDL II computer code. Loads in the plane of the ring (from the steam generator) are applied to the model as a cosine distribution over 180 degrees of the ring and reacted at the snubber and strut attachment locations. Transverse inertia loads are reacted at the U-bolts 180 degrees apart. The results of the analysis are given in Table 5.4-26. The hydraulic snubbers used for the upper lateral restraint of the steam generator are analyzed in detail, for axial and transverse loading to ensure structural adequacy during a seismic event and a main steam line pipe rupture. In addition, the hydraulic snubber has been successfully subjected to a load test performed by the vendor, demonstrating the integrity of the hydraulic snubbing system, using Tefzel material for all the hydraulic seals. Rigid struts are not evaluated for the transverse loads due to their robust design.

A stress analysis of the snubber assemblies for combined axial (tension and compression) and bending loads is performed to substantiate the structural adequacy of all the components that comprise the snubber assemblies of the steam generator support system. The factor of safety for the components of each snubber assembly for combined axial and bending loads is obtained using the following interaction equation:

$$\frac{f_a}{F_a} + \frac{f_b}{F_b} \leq 1.0 \qquad (5.4\text{-}1)$$

For combined compression and bending, the secondary moment due to the compressive axial load is accounted for by modifying the preceding interaction equation according to Section 1.6 of the American Institute of Steel Construction, Inc., Manual of Steel Construction, Seventh Edition shown subsequently.

$$\frac{f_a}{F_a} + \frac{f_b}{(1-f_a/F_c)F_b} \leq 1.0 \qquad (5.4\text{-}2)$$

Where:

f_a = Computed axial stress

f_b = Computed bending stress

F_a = Axial compressive stress permitted if axial force alone existed

F_b = Compressive bending stress permitted if bending alone existed

F_c = Euler stress divided by factor of safety

For combined tension and bending, the interaction equation is not modified and the allowances are:

F_a = lesser of 1.2 S_y or 0.7 S_u

F_b = lesser of 1.2K S_y or 0.7 K S_u

K = Plastic shape factor

The tabulated stress values for the component supports are based on the minimum specified (not actual) ASME code material strength values (yield or ultimate) which are modified to reflect reduced values at elevated temperature where applicable.

5.4.15 Reactor Vessel Head Vent System

The reactor vessel head vent system (RVHVS) removes noncondensable gases and provides letdown capability from the reactor vessel head. This system is designed to mitigate a possible condition of inadequate core cooling or impaired natural circulation resulting from the accumulation of noncondensable gases in the RCS. The design of the RVHVS is in accordance with the requirements of NUREG-0737, Item II.B.1 (USNRC 1980).

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5.4.15.1 Design Basis

The RVHVS is designed to remove noncondensable gases and provide letdown capability from the reactor coolant system via remote manual operations from the control room. The system discharges to the PRT. The RVHVS is designed to vent a volume of hydrogen at system design pressure and temperature approximately equivalent to one-half of the reactor coolant system volume in 1 hour.

The system provides for venting the reactor vessel head by using only safety grade equipment. The RVHVS satisfies applicable requirements and industry standards, including ASME Code classification, safety classification, single-failure criteria, and environmental qualification.

All piping and equipment from the vessel head vent up to and including the second isolation valve in each flow path are designed and fabricated in accordance with ASME Section III, Class 1 requirements. The piping and equipment in the flow paths from the isolation valve to the modulating valves are designed and fabricated in accordance with ASME Section III, Class 2 requirements. The remainder of the piping and equipment is non-nuclear safety.

The isolation valves are qualified to IEEE Standards 323-1974, 344-1975, and 382-1972 (Section 3.11).

All supports and support structures comply with the requirements of the ASME Code.

The Class 1 piping used for the reactor vessel head vent is 1 inch schedule 160 and, therefore, in accordance with ASME III, is analyzed following the procedures of NC-3600 for Class 2 piping.

For all plant operating conditions the piping stresses are shown to meet the ASME III requirements with a design temperature of 650°F and a design pressure of 2,485 psig.

5.4.15.2 System Description

The RVHVS consists of two parallel flow paths with redundant isolation valves in each flow path. The venting operation uses only one of these flow paths at any one time. The equipment design parameters are listed in Table 5.4-30.

The active portion of the system consists of four l-inch open/close solenoid-operated isolation valves connected to the existing 1 inch vent pipe, which is located near the center of the reactor vessel head. The system design with two valves in series in each flow path minimizes the possibility of reactor coolant pressure boundary leakage. The isolation valves in one flow path are powered by one vital power supply and the valves in the second flow path are powered

by a second vital power supply. The isolation valves are fail closed normally closed valves.

The vent system piping is supported to ensure that the resulting loads and stresses on the piping and on the vent connection to the vessel head are acceptable.

The support for attaching the head vent system piping to the CRDM seismic support platform is a two-part clamp configuration, called a double bolt riser clamp. The clamp and associated bolts, nuts, spacers, and washers, are made of stainless steel. A gap exists between the 1 inch head vent pipe and the support clamp to allow for thermal expansion in the vertical direction. A flange is provided in the vent piping for disconnecting the piping for head removal during refueling.

5.4.15.3 Safety Evaluation

If one single active failure prevents a venting operation through one flow path, the redundant flow path is available for venting. The two isolation valves in each flow path provide a similar method of isolating the venting system. With the two valves in series, the failure of any one valve or power supply will not inadvertently open a vent path. Thus the combination of safety grade train assignments and valve failure modes will not prevent vessel head venting nor venting isolation with any single active failure.

The RVHVS has two normally deenergized valves in series in each flow path. This arrangement eliminates the possibility of an opened flow path due to the spurious movement of one valve. As such, power lockout to any valve is not considered necessary.

A break of the RVHVS line would result in a small LOCA of not greater than l-inch diameter. Such a break is similar to those analyzed in WCAP-9600 (Westinghouse 1979). Since a break in the head vent line would behave similarly to the hot leg break case presented in WCAP-9600 (Westinghouse 1979), the results presented therein are applicable to a RVHVS line break. This postulated vent line break, therefore, results in no calculated core uncovery.

5.4.15.4 Inspection and Testing Requirements

Inservice inspection is conducted in accordance with Section 6.6.

5.4.15.5 Instrumentation Requirements

The system is operated from the control room. The isolation valves have stem position switches. The position indication from each valve is monitored in the control room by status lights.

The reactor head vent pipe temperature element provides an indicator for reactor head vent pipe temperature and an alarm for reactor head vent pipe temperature high.

5.4.16 References for Section 5.4

DeRosa, P.; Rinne, W.; Massie, H. N. Jr.; and Mitchell, P. 1978. Evaluation of Steam Generator Tube, Tube-Sheet, and Divider Plate Under Combined LOCA plus SSE Conditions. WCAP-7832-A.

U.S. Nuclear Regulatory Commission (USNRC) 1980. Clarification of TMI Action Plan Requirements. NUREG-0737.

USNRC 1981. Standard Technical Specification for Westinghouse Pressurized Water Reactors. NUREG-0452, Revision 4.

Westinghouse Electric Corporation (Westinghouse) 1973. Reactor Coolant Pump Integrity in LOCA. WCAP-8163.

Westinghouse 1979. Report on Small Break Accidents for Westinghouse NSSS System. WCAP-9600, June 1979 (Section 3.2).

Westinghouse 1981a. Personal communication between R. W. Jurgensen, Westinghouse Owners Group Chairman, and P. C. Check, USNRC. Letter (OG-57), dated April 20, 1981.

Westinghouse 1981b. Personal communication between R. J. Jurgensen, Westinghouse Owners Group Chairman, and D. G. Eisenhut, USNRC. Letter (OG-64), dated November 30, 1981.

Tables for Section 5.4

TABLE 5.4-1

REACTOR COOLANT PUMP DESIGN PARAMETERS

Pump	
Unit design pressure (psig)	2,485
Unit design temperature (°F)	650*
Unit overall height (ft)	26.93
Seal water injection (gpm)	8
Seal water return (gpm)	3
Cooling water flow (gpm)	40
Maximum continuous cooling water inlet temperature (°F)	105
Capacity (gpm)	95,200***
Developed head (ft)	266
NPSH required (ft)	Figure 5.4-2
Pump discharge nozzle, inside diameter (in)	27 ½
Pump suction nozzle, inside diameter (in)	31
Speed (rpm)	1,189
Water volume (ft^3)	81**
Weight, dry (lb)	195,520
Motor	
Type	Drip proof, squirrel Cage induction, water/ air cooled
Power (hp)	6,000
Voltage (V)	4,160
Phase	3
Frequency (Hz)	60
Cooling Water (gpm)	
Motor air cooler	220
Upper oil cooler	170
Lower oil cooler	6
Current	
Starting	4,800 amp @ 4,160 V
Input, hot reactor coolant	688 ± 14 amp
Input, cold reactor coolant	904 ± 18 amp
Pump assembly moment of inertia, maximum ($lb\text{-}ft^2$)	82,000

NOTES:

* Design temperature of pressure retaining parts of the pump assembly exposed to the reactor coolant and injection water on the high pressure side of the controlled leakage seal shall be that temperature determined for the parts for a primary loop temperature of 650°F.

** Composed of reactor coolant in the casing and of injection and cooling water in the pump exchanger.

*** Value is greater than core thermal design flow (See Table 5.1-1).

TABLE 5.4-2

REACTOR COOLANT PUMP NONDESTRUCTIVE EXAMINATION PROGRAM

Component	RT*	UT**	PT***	MT****
Castings	yes		yes	
Forgings				
Main shaft		yes		yes
Main studs		yes		yes
Flywheel (rolled plate)		yes		
Weldments				
Circumferential	yes		yes	
Instrument connections			yes	

NOTES:

*RT - Radiographic.
**UT - Ultrasonic.
***PT - Dye penetrant.
****MT - Magnetic particle.

TABLE 5.4-5

STEAM GENERATOR DESIGN DATA

Design pressure, reactor coolant side (psig)	2,485
Design pressure, steam side (psig)	1,085
Design pressure, primary to secondary (psi)	1,600
Design temperature, reactor coolant side (°F)	650
Design temperature, steam side (°F)	600
Design temperature, primary to secondary (°F)	650
Total heat transfer surface area (ft^2 per generator)	51,300*
Maximum moisture carryover (wt/%)	0.25
Overall height (ft-in)	67-8
Number of u-tubes per generator	3,376
U-Tube nominal diameter (in)	0.875
Tube wall nominal thickness (in)	0.050
Number of manways per generator	4
Inside diameter of manways (in)	16
Minimum number of handholes per generator/size (in)	2/6.0
Minimum number of inspected ports per generator/size (in)	4/2.0
Steam flow (lbs/hr per generator)	See Table 5.1-1

<u>NOTES</u>:

*Based on 3376 tubes.

TABLE 5.4-6

STEAM GENERATOR NONDESTRUCTIVE EXAMINATION

Component	RT[1]	UT[2]	PT[3]	MT[4]	ET[5]
Tubesheet					
Forging		yes		yes	
Cladding		yes[6]	yes		
Channel Head (if fabricated)					
Fabrication	yes[7]	yes[8]		yes	
Cladding			yes		
Secondary Shell and Head					
Plates		yes			
Tubes		yes			yes
Nozzles (Forgings)		yes		yes	
Weldments					
Shell, longitudinal	yes			yes	
Shell, circumferential	yes			yes	
Cladding (channel head-tubesheet joint cladding restoration)			yes		
Primary nozzles to fab head	yes			yes	
Manways to fab head	yes			yes	
Steam and feedwater nozzle to shell	yes			yes	
Support brackets				yes	
Tube to tubesheet			yes		
Instrument connections (primary and secondary)				yes	
Temporary attachments after removal				yes	

TABLE 5.4-6 (Cont)

Component	RT[1]	UT[2]	PT[3]	MT[4]	ET[5]
After shop hydrostatic test (all major boundary welds and complete cast channel head - where accessible)				yes	
Nozzle safe ends (if weld deposit)	yes		yes		

NOTES:

1. RT - Radiographic.
2. UT - Ultrasonic.
3. PT - Dye penetrant.
4. MT - Magnetic particle.
5. ET - Eddy current.
6. Flat surfaces only.
7. Weld deposit.
8. Base material only.

TABLE 5.4-7

REACTOR COOLANT PIPING DESIGN PARAMETERS

Reactor Inlet Piping	
Inside diameter (in)	27.5
Nominal wall thickness (in)	2.32
Reactor Outlet Piping	
Inside diameter (in)	29
Nominal wall thickness (in)	2.45
Coolant Pump Suction Piping	
Inside diameter (in)	31
Nominal wall thickness (in)	2.60
Pressurizer Surge Line Piping	
Nominal pipe size (in)	14
Nominal wall thickness (in)	1.406
Reactor Coolant Loop Piping	
Design/operating pressure (psig)	2,485/2,235
Design temperature (°F)	650
Pressurizer Surge Line	
Design pressure (psig)	2,485
Design temperature (°F)	680
Pressurizer Safety Valve Inlet Line	
Design pressure (psig)	2,485
Design temperature (°F)	680
Pressurizer Power Operated Relief Valve Inlet Line	
Design pressure (psig)	2,485
Design temperature (°F)	680
Pressurizer Relief Tank Inlet Line	
Design pressure (psig)	700
Design temperature (°F)	600

TABLE 5.4-8

REACTOR COOLANT PIPING NDE DURING FABRICATION

	RT*	UT**	PT***
Fittings and Pipe (Castings)	yes		yes
Fittings and Pipe (Forgings)		yes	yes
Weldments			
Circumferential	yes		yes
Nozzle to runpipe (Except no RT* for nozzles less than 6 inches)	yes		yes
Instrument connections			yes
Castings	yes		yes (after finishing)
Forgings		yes	yes (after finishing)

NOTES:

*RT - Radiographic.
**UT - Ultrasonic.
***PT - Dye penetrant.

TABLE 5.4-9

DESIGN BASES FOR RESIDUAL HEAT REMOVAL SYSTEM OPERATION

Residual heat removal system placed in operation (hours after reactor shutdown	4
Reactor coolant system initial pressure (psig)	400
Reactor coolant system initial temperature (°F)	350
Primary plant component cooling water heat exchanger maximum outlet temperature (°F)	120 *
Reactor coolant system temperature at end of cooldown (°F)	140
Residual heat removal system cooldown time (hours after system placed in operation)	47
Decay heat generation at 51 hours after reactor shutdown (Btu/hr)	47×10^{6}

*Temperature ranges from 80 - 120°F.

TABLE 5.4-10

FAILURE MODES AND EFFECTS ANALYSIS
RESIDUAL HEAT REMOVAL SYSTEM

Item No.	Component and Identification No.	Function	Failure Mode	Effect on System	Method of Detection	Remarks
1	Gate valve/motor operated 8702A and 8702B	Provides isolation of the RHRS from the RCS on the suction side of the RHRS - N.O. during RHRS operation	Closed	No flow through RHRS; potential pump damage	Indicator lights on control board show valve position; low flow alarms. Suction valve position switches closed stops RHR pumps.	Heat removal from RCS via SGs
2	Gate valve/motor-operated 8701A and 8701B	Same as item 1	Closed	Same as item 1	Same as item 1	Same as item 1
3	Residual heat removal pump no. 1 no. 2	Deliver reactor coolant flow through the RHRS heat exchangers to meet plant cooldown requirements - running during RHRS operation	Fails to run	Pump will not provide coolant to its heat exchanger	Indication at control board, low flow alarm	Redundant train will provide necessary cooling
4	Gate valve/motor-operated 8703A or 8703B	Provides isolation of the RHRS from the RCS on the discharge side of the RHRS	Closed	No flow through the affected RHRS train	Same as item 3	Redundant train will provide necessary cooling
5	Residual heat exchangers no. 1 or no. 2	Remove residual and decay heat from RCS coolant during the cooldown transient	No heat transfer	Affected RHRS train will be inoperable	Indication at control board low flow alarm	Redundant train will provide necessary cooling
6	Butterfly valve air-operated HCV-758A or HCV-758B	Controls flow rate through RHRS heat exchanger variable position during RHRS operation	a. Open	Excessive cooldown rate may be experienced if associated bypass coincidentally fails full closed	Indication at control board	Redundant train will provide necessary cooling

TABLE 5.4-10 (Cont)

Item No.	Component and Identification No.	Function	Failure Mode	Effect on System	Method of Detection	Remarks
			b. Closed	Increase in cooldown time possible	Same as item 6a	Same as item 6a
			c. As is	Increase in cooldown time possible	Same as item 6a	Same as item 6a; effect on cooldown depends on failure position
7	Butterfly valve air-operated FCV-605A or FCV-605B	Controls total return flow rate to RCS. Variable position during RHRS operation	a. Open	Increased cooldown time possible	Same as item 6a	Redundant train will provide necessary cooling
			b. Closed	Decreased total return flow to RCS	Same as item 6a	No other effects
				Excessive cooldown rate may be experienced if associated HCV coincidentally fails full open	Same as item 6a	Redundant train will provide necessary cooling
			c. As is	Increase in cooldown time possible	Same as item 6a	Redundant train will provide necessary cooling. Effect on cooldown depends on failure position
8	Flow meter 605A or 605B	Monitors total return flow to the RCS	Low	FCV-605A/B opens - Refer to item 7a	Same as item 6a	Refer to item 7a

TABLE 5.4-11

RESIDUAL HEAT REMOVAL SYSTEM COMPONENT DATA

Residual Heat Removal Pump

Number	2
Design pressure (psig)	600
Design temperature (°F)	400
Design flow (gpm)	4,000
Design head (ft)	225
NPSH required at 4000 gpm (ft)*	16
Power (hp)	300

Residual Heat Removal Heat Exchanger

Number	2	
Design heat removal capacity (Btu/hr)	29×10^6	
Estimated (UA Btu/hr °F)	1.1×10^6	
	Tube-side	Shell-side
Design pressure (psig)	600	150
Design temperature (°F)	400	200
Design flow (lb/hr)	1.97×10^6	3.23×10^6
Material	Austenitic stainless steel	Carbon steel
Fluid	Reactor coolant	Component cooling water

NOTE:

* NPSH value is given with respect to the centerline of the pump suction nozzle

TABLE 5.4-12

PRESSURIZER DESIGN DATA

Design pressure (psig)	2,485
Design temperature (°F)	680
Surge line nozzle diameter (in)	14
Heatup rate of pressurizer using heaters only (°F/hr)	55
Internal volume, nominal (ft^3)	1,400

TABLE 5.4-13

REACTOR COOLANT SYSTEM DESIGN PRESSURE SETTINGS (psig)*

Hydrostatic test pressure	3,107
Design pressure	2,485
Pressurizer safety valves (begin to open)	2,485
High-pressure reactor trip	2,385
High-pressure alarm	2,310
Pressurizer power-operated relief valves	2,335**
Pressurizer spray valves (full open)	2,310
Pressurizer spray valves (begin to open)	2,260
Pressurizer proportional heaters (begin to operate)	2,250
Operating pressure	2,235
Pressurizer proportional heaters (full operation)	2,220
Pressurizer backup heaters (on)	2,210
Low-pressure alarm	2,185
Pressurizer power-operated relief valve interlock	2,335***
Low-pressure reactor trip (typical, but variable)	1,945

NOTES:

*See Technical Specifications for limiting values.
**At 2,335 psig, an increasing pressure signal initiates actuation (opening) of these valves. Remote manual control is also provided.
***At 2,335 psig, a decreasing pressure signal initiates closure of these valves. Remote manual control is also provided.

TABLE 5.4-14

PRESSURIZER NONDESTRUCTIVE EXAMINATION PROGRAM

Component	RT(1)	UT(2)	PT(3)	MT(4)
Heads				
Plates		yes		
Cladding			yes	
Shell				
Plates		yes		
Cladding			yes	
Heaters				
Tubing(5)		yes	yes	
Centering of element	yes			
Nozzle (Forging)		yes	yes(6)	yes(6)
Weldments				
Shell, longitudinal	yes			yes
Shell, circumferential	yes			yes
Cladding			yes	
Nozzle safe end	yes		yes	
Instrument connection			yes	
Support skirt, longitudinal seam	yes			yes
Support skirt to lower head		yes		yes
Temporary attachments (after removal)				yes
All external pressure boundary welds after shop hydrostatic test				yes

NOTES:

1. RT - Radiographic.
2. UT - Ultrasonic.
3. PT - Dye penetrant.
4. MT - Magnetic particle.
5. Or a UT and ET (Eddy Current).
6. MT or PT.

TABLE 5.4-15

PRESSURIZER RELIEF TANK DESIGN DATA

Design pressure (psig)		100
Normal operating pressure (psig)		3
Final operating pressure (psig)		50
Rupture disc release pressure (psig)	Nominal	91
	Range	86-100
Normal water volume (ft^3)		900
Normal gas volume (ft^3)		400
Design temperature (°F)		340
Initial operating water temperature (°F)		120
Final operating water temperature (°F)		200
Total rupture disc relief capacity at 100 psig (lb/hr)		1.2×10^6
Cooling time required following maximum discharge (approximate) utilizing spray feed and bleed (hr)		1
Relief valve set pressure (psig)		75

TABLE 5.4-16

RELIEF VALVE DISCHARGE TO THE PRESSURIZER RELIEF TANK

Reactor Coolant System

3 Pressurizer safety valves
3 Pressurizer power-operated relief valves

Reactor Heat Removal System

2 Residual heat removal pump suction line from the reactor coolant system

Chemical and Volume Control System

1 Seal water return line
1 Letdown line
1 Charging line

TABLE 5.4-17

REACTOR COOLANT SYSTEM VALVE DESIGN PARAMETERS

Design/normal operating pressure (psig)	2485/2235
Pre-operational plant hydro test (psig)	3107
Design temperature (°F)	650

TABLE 5.4-18

LOOP STOP VALVE DESIGN PARAMETERS

Design/normal operating pressure (psig)	2,485/2,235
Hydrostatic test pressure shop test/ pre-operational hydrostatic test pressure (psig)	3,350/3,107
Design temperature (°F)	650
Hot leg valve size, nominal (in)	29
Cold leg valve size, nominal (in)	27.50
Open/close travel time (sec)	210

TABLE 5.4-19

REACTOR COOLANT SYSTEM VALVES NONDESTRUCTIVE
EXAMINATION PROGRAM

Boundary Valves, Pressurizer Power-Operated Relief Valves and Safety Valves	RT*	UT**	PT***
Castings (larger than 4 inches)	yes		yes
(2 inches to 4 inches)	yes****		yes
Forgings (larger than 4 inches)	*****	*****	yes
(2 inches to 4 inches)			yes

NOTES:

*RT - Radiographic.
**UT - Ultrasonic.
***PT - Dye penetrant.
****Weld ends only.
*****Either RT or UT.

TABLE 5.4-20

PRESSURIZER VALVES DESIGN PARAMETERS

Pressurizer Safety Valves	
Number	3
Relieving capacity, ASME rated flow, (lb/hr) each	345,000
Set pressure (psig)	2,485
Design temperature (°F)	650
Fluid	Saturated steam
Backpressure	
Normal (psig)	3 to 5
Expected during discharge (psig)	500
Pressurizer Power-Operated Relief Valves	
Number	3
Design pressure (psig)	2,485
Design temperature (°F)	650
Relieving capacity at 2,350 psia, (lb/hr) (per valve)	232,000
Fluid	Saturated steam
Transient condition (°F)	(Superheated steam) 680

TABLE 5.4-21

LOAD COMBINATIONS AND DESIGN ALLOWABLE STRESSES
FOR ASME III, CLASS 1 EQUIPMENT SUPPORTS

Equipment Support	Load* Category	Stress Limits: Tension Stress	Bending Stress	Membrane and Bending Stress	Primary Membrane Stress Intensity	Primary Membrane & Primary Bending Stress Intensity	Primary & Secondary Stress Intensity	Shear Stress	Reference Source
Steam generator and reactor coolant pump supports, pressurizer supports	Normal and upset	0.6 σ_{yield}	0.6 σ_{yield}	N/A	N/A	N/A	N/A	0.4 σ_{yield}	AISC Sections 1.5 through 1.10
Reactor vessel structural support and reactor vessel support/leveling device	Normal and upset	N/A	N/A	N/A	S_m	1.5 S_m	3.0 S_m	0.6 S_m	ASME Section III Subsection NF3200 as a guide
Steam generator, reactor coolant pump, pressurizer, and reactor vessel supports including the reactor vessel support/leveling devices	Faulted	N/A	N/A	The smaller of 1.2K σ_{yield} or 0.7K σ_{ult}**,***	N/A	N/A	N/A	0.67 σ Where σ is the smaller of 1.2 σ_{yield} or 0.7 σ_{ult} ,***	ASME Section III, Subsection NF-3230 Appendix F as a guide

NOTES.

*The following loads are included in each loading condition:

Normal - deadweight, thermal, and steady state pressures,

Upset - Normal ± OBE,

Faulted - Normal ± SSE and pipe ruptures using the absolute sum technique

**K is a plastic shape factor.

***The Faulted Load Category Stress Limits are below σ_{yield} (0.60 σ_{yield} for shear) when safe shutdown earthquake (SSE) and loss of coolant accident (LOCA) loads are combined by the square root of the sum of the squares (SRSS) method.

TABLE 5.4-23

MAXIMUM STEAM GENERATOR AND PUMP SUPPORT FRAME EMBEDMENT LOADS*

Component	Location	Direction	Normal Operation** (kips)	Seismic SSE (kips)	Pipe Ruptures*** (kips)	Total Upset kips	Total Faulted (kips)
Steam Generator	12	+Z	+249	213	+464	+462	+760
		-Z	-311		-588	-524	-937
Support Frames	13	+Z	+15	248	+155	+263	+307
		-Z	-234		-435	-483	-735
	14	+Z	+8	237	+236	+245	+343
		-Z	-252		-364	-489	-687
	15	+Z	+137	216	+308	+353	+513
		-Z	-276		-537	-492	-855
	16	±Y	115	204	586	319	735
	17	±Y	78	245	300	322	465
Reactor Coolant	9	+Z	+254	580	+262	+834	+890
		-Z	+14		-557	-566	-791
Pump Support	10	+Z	-73	46	+822	-27	+750
		-Z	-246		-211	-292	-462
Frames	11	+Z	-222	630	+6	+408	+409
		-Z	-437		-760	-1067	-1425

NOTES:

*Fig. 5.4-21 illustrates location and position direction of loads. All unsigned loads are ±.
**Includes the effects of deadweight, thermal, and initial or steady state pressure.
***Pipe rupture loads are due to main steam line, feedwater line, and pressurizer spray line breaks.
****Includes normal operation and seismic (SSE).

TABLE 5.4-24

STEAM GENERATOR SUPPORT
SNUBBER AND STRUT EMBEDMENT LOADS(a,b)

Component	Location	Condition	Fx (kips)	Fy (kips)	Fz (kips)
Steam generator upper support snubbers	5,7	Upset(c)	148	4	4
		Faulted(d)	500	7	27
Steam generator upper support struts	6,8	Upset(c)	164	4(e)	4(e)
		Faulted(d)	854	7(e)	27(e)

NOTES:

(a) Figure 5.4-21 illustrates location and direction of loads. All loads are ±.
(b) Maximum for all loops.
(c) Includes seismic (SSE), thermal, and deadweight.
(d) Includes deadweight, thermal, seismic (SSE), and main steam pipe rupture.
(e) Lateral loads are based on a Main Steam Line Break plus weight plus SSE condition for a snubber. These are conservative for a strut, which has lower mass than a snubber.

TABLE 5.4-25

DESIGN MARGINS FOR PRIMARY MEMBERS
OF REACTOR PRESSURE VESSEL SUPPORT

			Upset Conditions			Faulted Conditions			
Support Section Member*	Material Designation	S (ksi)	Actual Stress (ksi)	Allowable Stress (ksi)	Factor of Safety	Material Stress** (ksi)	Actual Stress (ksi)	Allowable Stress*** (ksi)	Factor of Safety****
Reactor Pressure Vessel Interface									
Gib keys	A237 GrH		-	-	-	174	85.97	121.9	1.42
Gib gussets	A516 Gr70	23.2	9.12	34.8	3.81	36.9	bending 54.15	66.44	1.07
							tension 5.42	44.29	
Restraint plate	A237 GrH		-	-	-	174	53.61	182.9	3.41
Upper shell	A516 Gr70	23.2	12.02	34.8	2.89	36.9	53.18	66.44	1.24
Mounting bolts	SA540 Cl 1		-	-	-	140.5	89.2	98.3	1.10
Primary Shield Wall Interface (Grout)									
Outer shell at the grout	SA516 Gr70	23.2	12.78	23.2	1.81	36.3	41.33	43.56	1.05
Base Flange Interface									
Shell at the base flange	SA516 Gr70	23.2	18.28	34.8	1.90	36.3	42.55	43.56	1.02
Flange	SA516 Gr70	23.3	13.13	34.95	2.66	38.0	31.21	68.4	2.19
Gussets	SA516 Gr70	23.3	14.0	34.95	2.46	38.0	35.40	68.4	1.93
Shear keys	SA516 Gr60	20.0	9.04	12.0	1.32	32.0	15.9	23.04	1.44
Bolts	SA193 B7	35.0	32.26	35.0	1.08	125.0	79.51	87.50	1.10

NOTES:

*Figures 5.4-10 and 5.4-11 provides illustrations.
**Material stress is either minimum yield or ultimate at temperature which is then used to determine the allowable stress.
***The allowable stress is determined as a function of the material stress per Table 5.4-21.
****These factors of safety are based on a LOCA and SSE design basis. Given the primary loop pipe rupture postulation exemption, the results are very conservative and are presented for information only.

TABLE 5.4-26

FACTORS OF SAFETY FOR PRIMARY MEMBERS OF STEAM GENERATOR AND REACTOR COOLANT PUMP SUPPORTS

Support Section Member[2]	Material Designation	Material Stress[3] (ksi)	Faulted Condition Actual Stress (ksi)	Faulted Condition Allowable Stress[4] (ksi)	Factor of Safety[1]
Steam Generator					
Lower frame weldment					
Frame members	A36	58.0	39.5	40.6	1.02
Foot vertical support	A36	55.2	31.64	38.6	1.22
Column base	A36	58.0	35.53	60.9+	1.71
Shear fitting	A36	58.0	17.35	27.06	1.56
Steam Generator Tiedown Bolts	A540-B23 Cl 1	165	89.2	115.5	1.29
Upper Ring Assembly					
Splice area					
Pin (bending)	A237 Cl H	170.0	129.1	148.8	1.15
Bolt (tension)	Carbon stl. com. grade	58.0	16.9	40.6	2.40
Spacer	A543 Cl 2	112.3	32.9	86.5	2.62
Splicer plate	A543 Cl 2	112.3	26.1	86.5	3.31
Ring	A543 Cl 2	112.3	37.0	86.5	2.33
Weld	E11018-M	100.0	13.0	42.0	3.22
Snubber Pin Area					
Pin (bending)	A237 Cl H	175.0	104.6	153.2	1.46
Ring	A543 Cl 2	112.3	37.9	86.5	2.28
Weld	E11018-M	100.0	22.6	42.0	1.85
U-Bolt area					
U-Bolt (tension)	A325	105.0	63.4	73.5	1.15
Ring	A543 Cl 2	112.3	79.6	86.5	1.08

TABLE 5.4-26 (Cont)

Support Section Member[2]	Material Designation	Material Stress[3] (ksi)	Faulted Condition Actual Stress (ksi)	Allowable Stress[4] (ksi)	Factor of Safety[1]
Reactor Coolant Pump					
Frame weldment					
Columns	A237, C1G	160.5			
Compression		72.2	85.6		
Bending		15.4	191.0	1.09	
Tension		75.8	112.3		
Bending		8.1	191.0	1.39	
Beam flange	A36	67.8	63.9	71.2	1.11
Foot support	A237, Clf	115.0	93.6	120.75	1.29
Casing tiedown bolts	A579, GR 72	247	153.2	172.9	1.13

NOTES:

1. These factors of safety for the steam generator lower support and the reactor coolant pump support are based on a LOCA and SSE design basis. Subsequent exemption from primary loop pipe rupture postulation has reduced the applied loads such that, despite the removal of lower support snubbers, the interface loads to support (Tables 5.4-23 and 5.4-24 and Figure 5.4-32) are less than the design basis loads. Therefore, the results are very conservative and are presented for information only. The upper support factors of safety are based on a postulated break in the main steam line.
2. Refer to Figure 5.4-13.
3. Material stress is either minimum specified yield or ultimate at temperature which is then used to determine the allowable stress.
4. The allowable stress is determined as a function of the material stress per Table 5.4-21.

TABLE 5.4-28

MINIMUM DESIGN MARGINS FOR PRESSURIZER SUPPORT*

Support Section Member**	Material Designation	Material Stress*** (ksi)	Faulted Actual Stress (ksi)	Faulted Allowable Stress**** (ksi)	Factor of Safety
Ring Girder Section at:	SA516 Gr 70				
Hanger support		36.8	62.80	66.24	1.05
Bracket		36.8	16.68	22.08	1.32
Bolt holes		36.8	20.85	22.08	1.06
Hanger Columns					
Column	SA106 Gr B	58.1	15.25	18.78	1.19
Adjusting stud	SA540 Gr B 23 Cl 1	151.5	109.87	117.20	1.06
Clevis pin	SA540 GR B 23 Cl4	131.9	109.87	128.80	1.14
Rod end	SA564	151.8	109.87	128.80	1.14
Upper Lug Restraint					
Shear pad	SA36	56.2	24.90	26.23	1.05
Shear plate	SA543 Cl 2	103.7	19.09	48.39	2.53
Lower Lateral Restraint					
Beam	A516 Gr 70	36.8	20.11	44.16	2.19
Bolts	SA540 Gr B23 Cl 3	141.7	27.62	99.19	3.59
Shear bars	SA36	56.2	14.98	59.01	3.93
Skirt Tie Down Bolts	SA540 Gr B23 Cl 2	151.7			
Fitted bolts			104.30	106.19	1.01
Non-fitted bolts			76.81	106.19	1.38

NOTES:

*The design margins are based on postulated breaks in the surge line which are exempted from the design basis by the application of Leak Before Break (LBB). These results, therefore, are very conservative and are presented for information only.

**Refer to Figure 5.4-14.

***Material stress is either minimum specified yield or ultimate at temperature which is then used to determine the allowable stress.

****The allowable stress is determined as a function of the material stress per Table 5.4-21.

TABLE 5.4-30

REACTOR VESSEL HEAD VENT SYSTEM EQUIPMENT
DESIGN PARAMETERS

Valves	
Number (6 solenoid, 1 manual)	7
Design pressure (psig)	2485
Design temperature (°F)	650
Maximum operating temperature (°F)	620
Piping	
Vent line, nominal diameter (inch)	1
Design pressure (psig)	2485
Design temperature (°F)	650
Maximum operating temperature (°F)	620

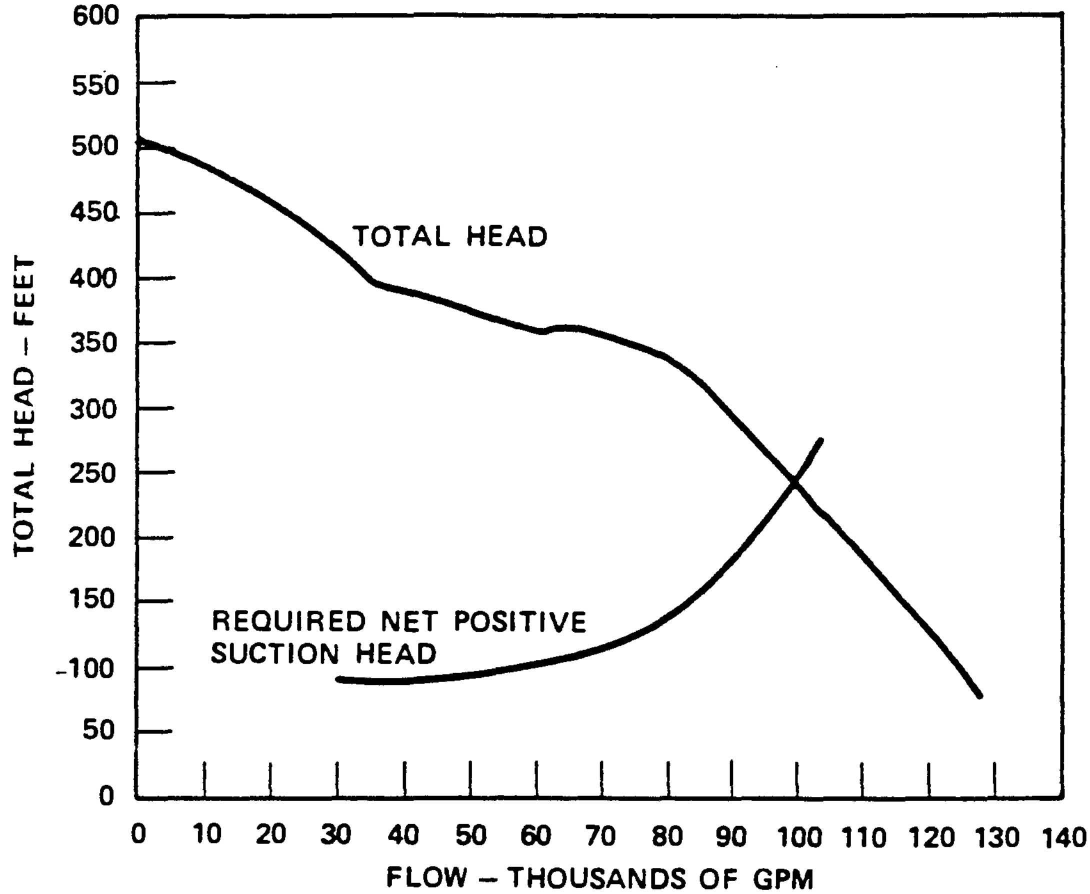


FIGURE 5.4-2
REACTOR COOLANT PUMP
ESTIMATED PERFORMANCE
CHARACTERISTIC CURVE
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

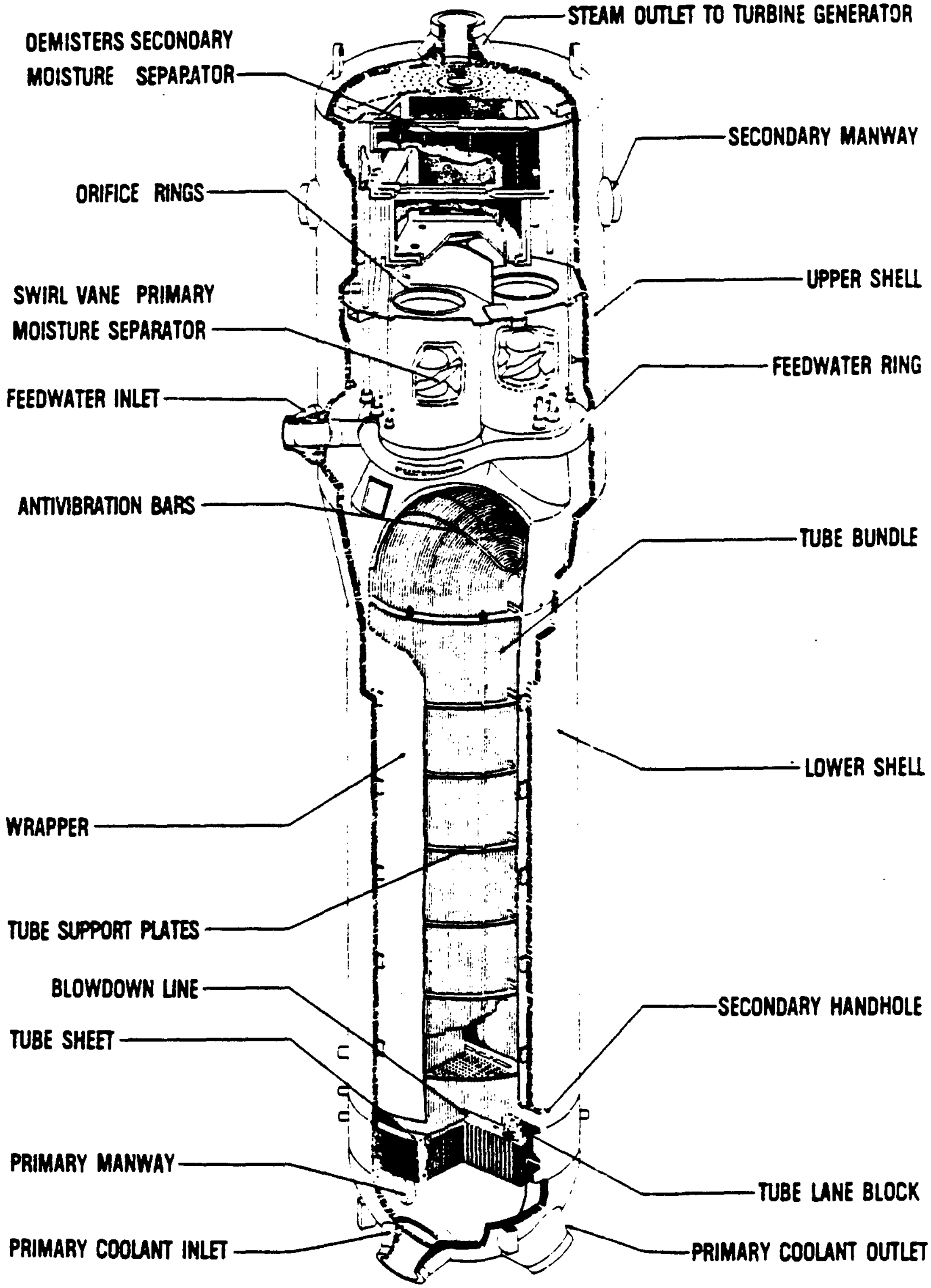
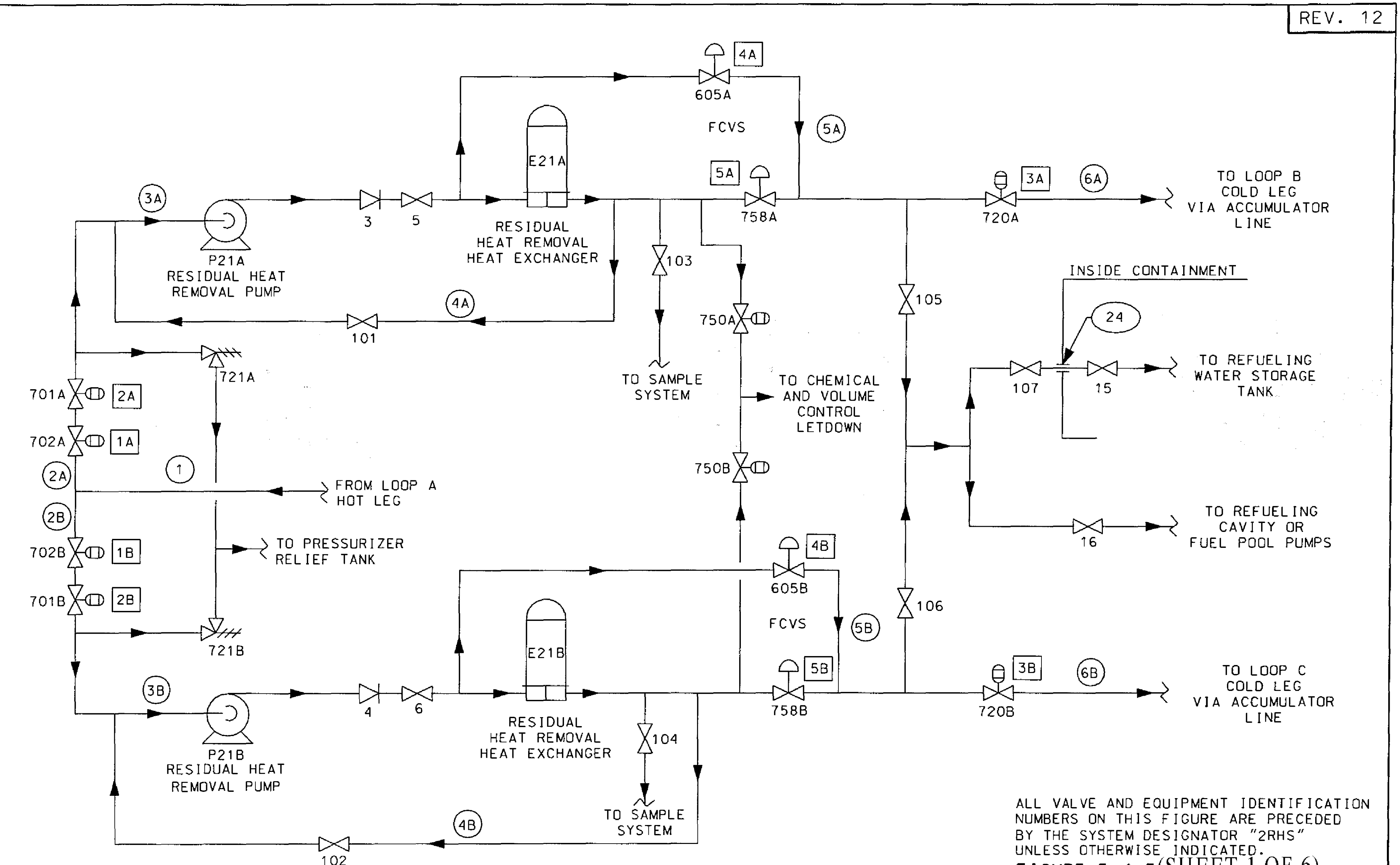


FIGURE 5.4-3
STEAM GENERATOR
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



ALL VALVE AND EQUIPMENT IDENTIFICATION NUMBERS ON THIS FIGURE ARE PRECEDED BY THE SYSTEM DESIGNATOR "2RHS" UNLESS OTHERWISE INDICATED.

FIGURE 5.4-5(SHEET 1 OF 6)
RESIDUAL HEAT REMOVAL SYSTEM PROCESS FLOW DIAGRAM

REFERENCE: STATION DRAWING OM 10-1
BEAVER VALLEY POWER STATION UNIT NO. 2
UPDATED FINAL SAFETY ANALYSIS REPORT

NOTE: THE SYMBOLS ☐ AND ◯ CORRESPOND TO VALVES AND PIPING LOCATIONS THAT ARE REFERRED TO IN THE NOTES TO THIS FIGURE.

LEGEND
FCVS FLOW CONTROL VALVES

FIGURE 5.4-5

MODES OF OPERATION

MODE A: Initiation of Residual Heat Removal

This mode presents the process flow conditions for the initiation of RHRS operation. This begins the second phase of plant cooldown, when the reactor coolant temperature and pressure have been reduced to 350°F and 400 psig by use of the steam generators, transferring heat to the secondary side.

Both RHR subsystems take suction from the reactor coolant loop 1 hot leg, discharging through heat exchangers with the return flow routed to two accumulator injection lines. During the initial phases of RHRS operation, reactor coolant flow through the heat exchangers is manually limited to control the rate of heat removal. The total flow is automatically regulated by flow control valves in the heat exchanger bypass lines to maintain a constant total return flow. The heat removal rate is limited to both control the RCS cooldown rate to 50°F/hr, based on equipment stress considerations, and to limit CCW temperature to a maximum of 120°F.

During this initial phase of RHRS operation, one RCP is maintained in operation.

MODE B: End Conditions of Normal Cooldown

This mode presents the process flow conditions for the completion of RHRS operation, 24 hours after RHRS initiation.

The flow distribution of this mode, all reactor coolant flow through the heat exchangers with the bypass isolated, characterizes the majority of RHRS operation.

Reactor coolant pump operation has also been terminated at this time, with all RCS cold legs now in equilibrium.

MODE C: Refueling

This mode presents the process flow conditions at the initiation of refueling. The RCS is eventually drained to the reactor vessel flange.

The RHRS flow through RHRS heat exchangers is reduced to ensure adequate NPSH to the RHR pump and to continue to remove decay heat.

FIGURE 5.4-5 (Cont)

VALVE ALIGNMENT CHART

Valve Number	Mode of Operation A	B	C
1A	O	O	O
1B	O	O	O
2A	O	O	O
2B	O	O	O
3A	O	O	O
3B	O	O	O
4A	P	C	C
4B	P	C	C
5A	P	P	P
5B	P	P	P

NOTES:

O = Open
C = Closed
P = Partial

FIGURE 5.4-5 (Cont)

MODE A: Initiation of Residual Heat Removal***

Location	Pressure (psig)	Temperature (°F)	Flow (gpm)*	Flow (lb/hr)**
1	400	350	8,000	3.57
2A	383	350	4,000	1.78
2B	383	350	4,000	1.78
3A	378	350	4,410	1.96
3B	378	350	4,410	1.96
4A	444	149	410	0.18
4B	444	149	410	0.18
5A	444	>350	2,980	1.33
5B	444	>350	2,980	1.33
6A	400	299	4,000	1.78
6B	400	299	4,000	1.78

FIGURE 5.4-5 (Cont)

MODE B: End Conditions of Normal Cooldown***

Location	Pressure (psig)	Temperature (°F)	Flow (gpm)*	Flow (lb/hr)**
1	0	140	8,000	3.98
2A	-	140	4,000	1.99
2B	-	140	4,000	1.99
3A	0	140	4,410	2.17
3B	0	140	4,410	2.17
4A	67	124	410	0.203
4B	67	124	410	0.203
5A	67	124	0	0
5B	67	124	0	0
6A	0	124	4,000	1.99
6B	0	124	4,000	1.99

FIGURE 5.4-5 (Cont)

MODE C1: Refueling (Subcritical + 6 days)***

Location	Pressure (psig)	Temperature (°F)	Flow (gpm)*	Flow (lb/hr)**
1	0	120	4,000	2.00
2A or 2B	-	120	4,000	2.00
3A or 3B	0	120	4,410	2.21
4A or 4B	67	<120	410	0.21
5A or 5B	67	<120	0	0
6A or 6B	0	<120	4,000	2.00

MODE C2: Refueling (Subcritical + 14 days)***

Location	Pressure (psig)	Temperature (°F)	Flow (gpm)*	Flow (lb/hr)**
1	0	120	1,500	0.75
2A or 2B	-	120	1,500	0.75
3A or 3B	7	120	1,990	0.99
4A or 4B	140	<120	490	0.25
5A or 5B	140	<120	0	0
6A or 6B	0	<120	1,500	0.75

NOTES:

*At reference conditions 120°F and 0 psig.
**x 10^6.
***Nominal temperature, pressure and flow valves are provided to satisfy Regulatory Guide 1.70, Section 5.4.7.2.

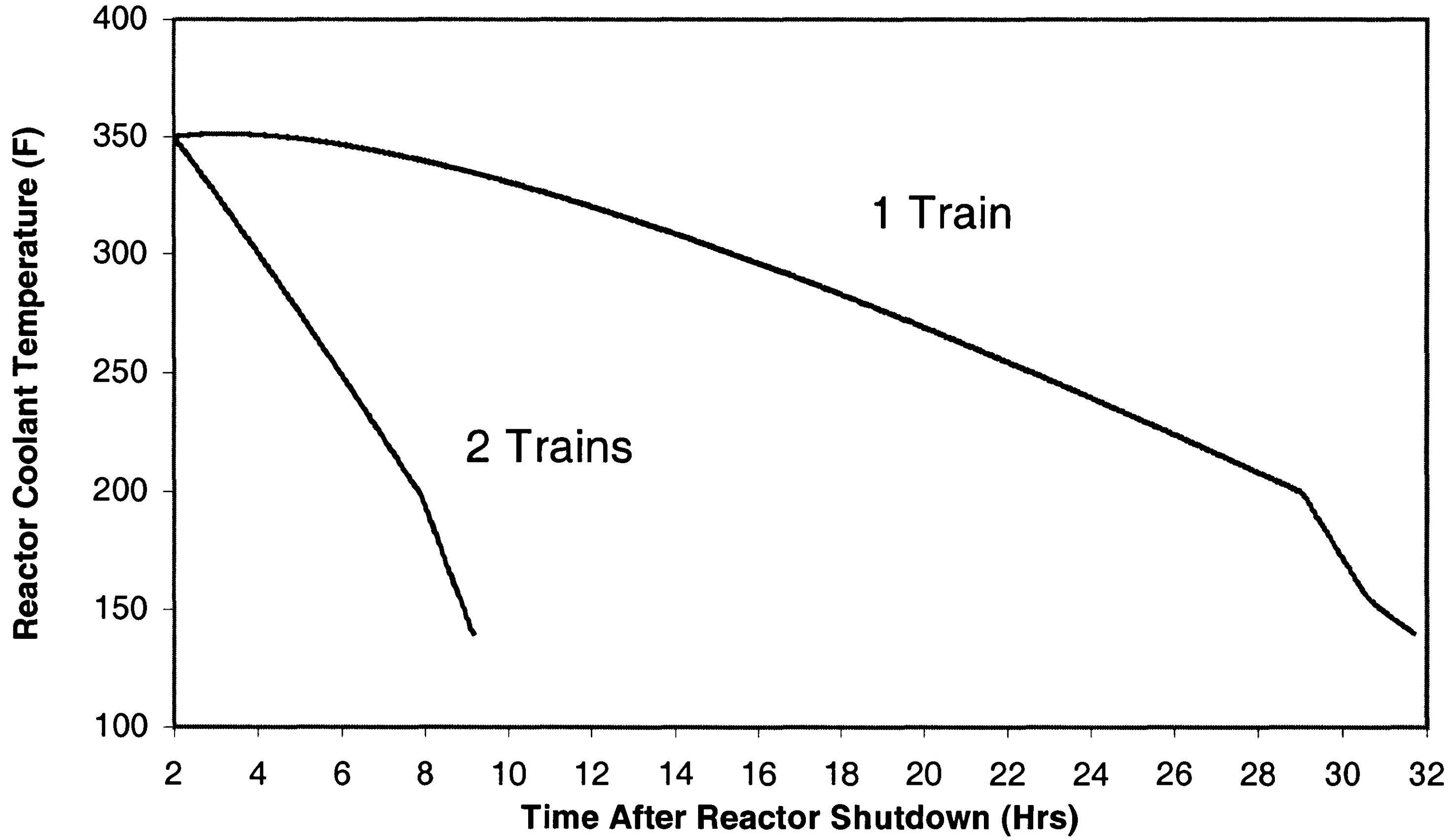


Fig. 5.4-6
RESIDUAL HEAT REMOVAL COOLDOWN

BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

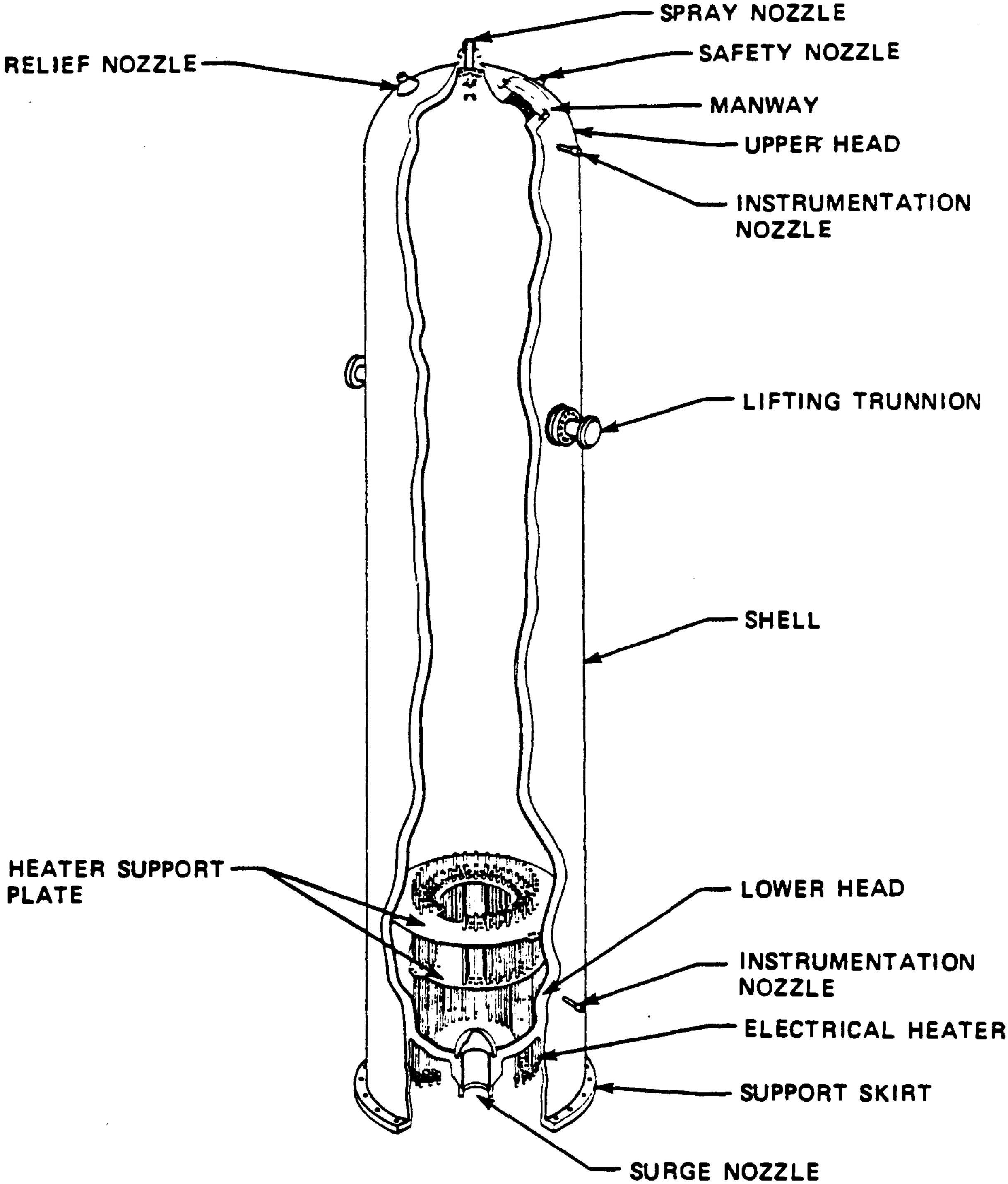


FIGURE 5.4-7 (SH. 1 OF 2)
PRESSURIZER AND
PRESSURIZER RELIEF TANK
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

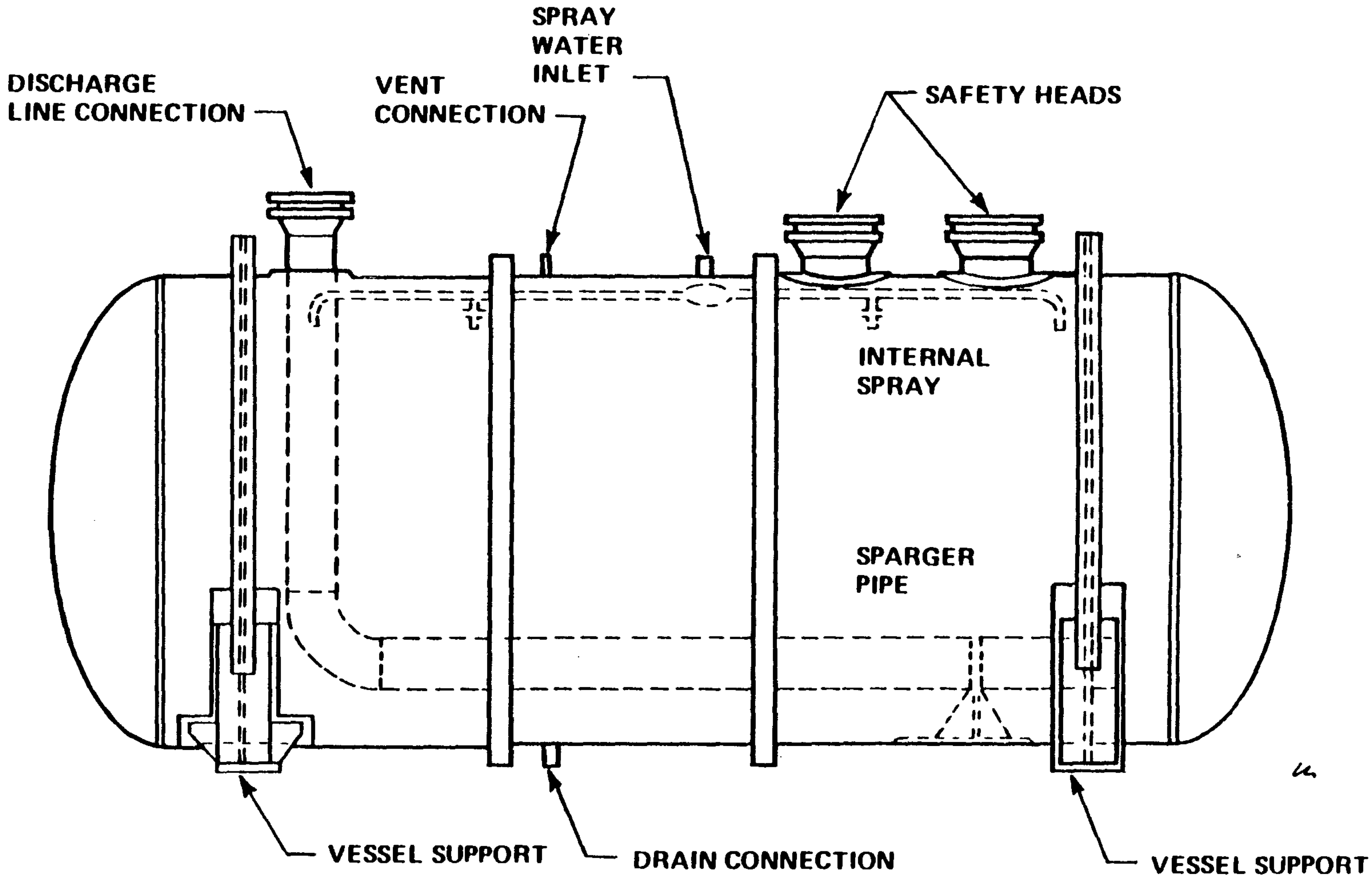


FIGURE 5.4-7 (SH. 2 OF 2)
PRESSURIZER AND
PRESSURIZER RELIEF TANK
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

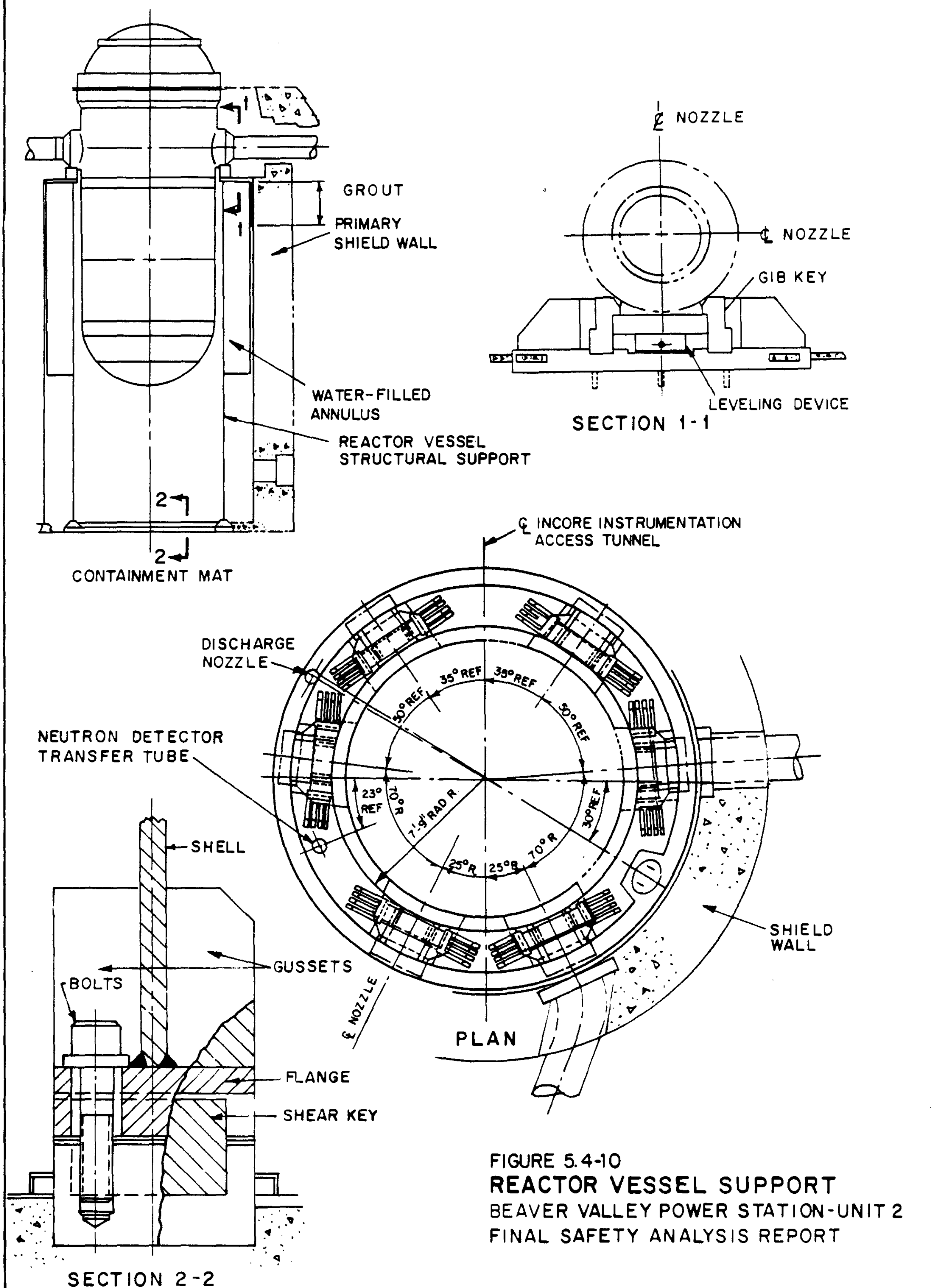


FIGURE 5.4-10
REACTOR VESSEL SUPPORT
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

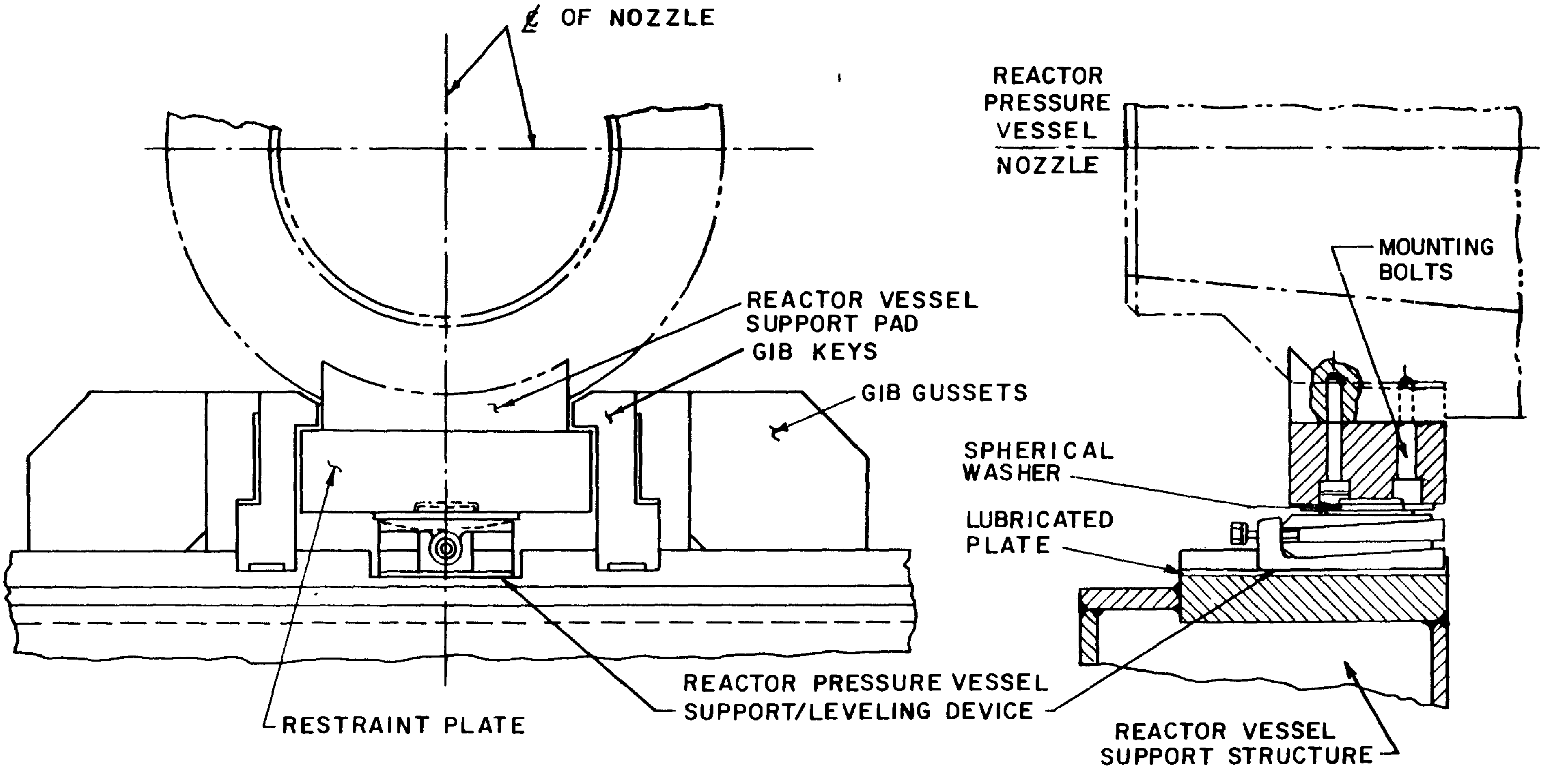


FIGURE 5.4-11
REACTOR VESSEL
SUPPORT/LEVELING DEVICE
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

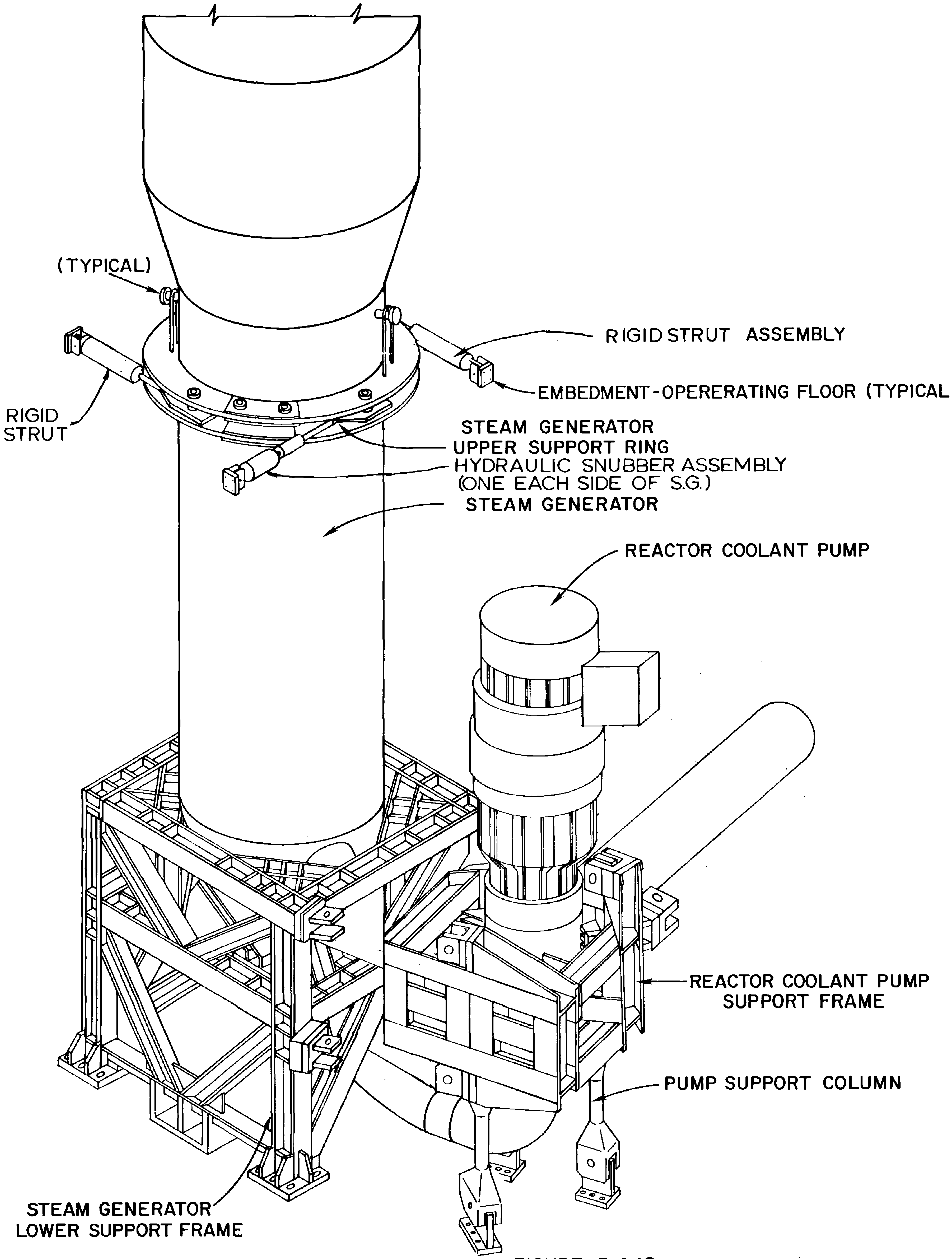


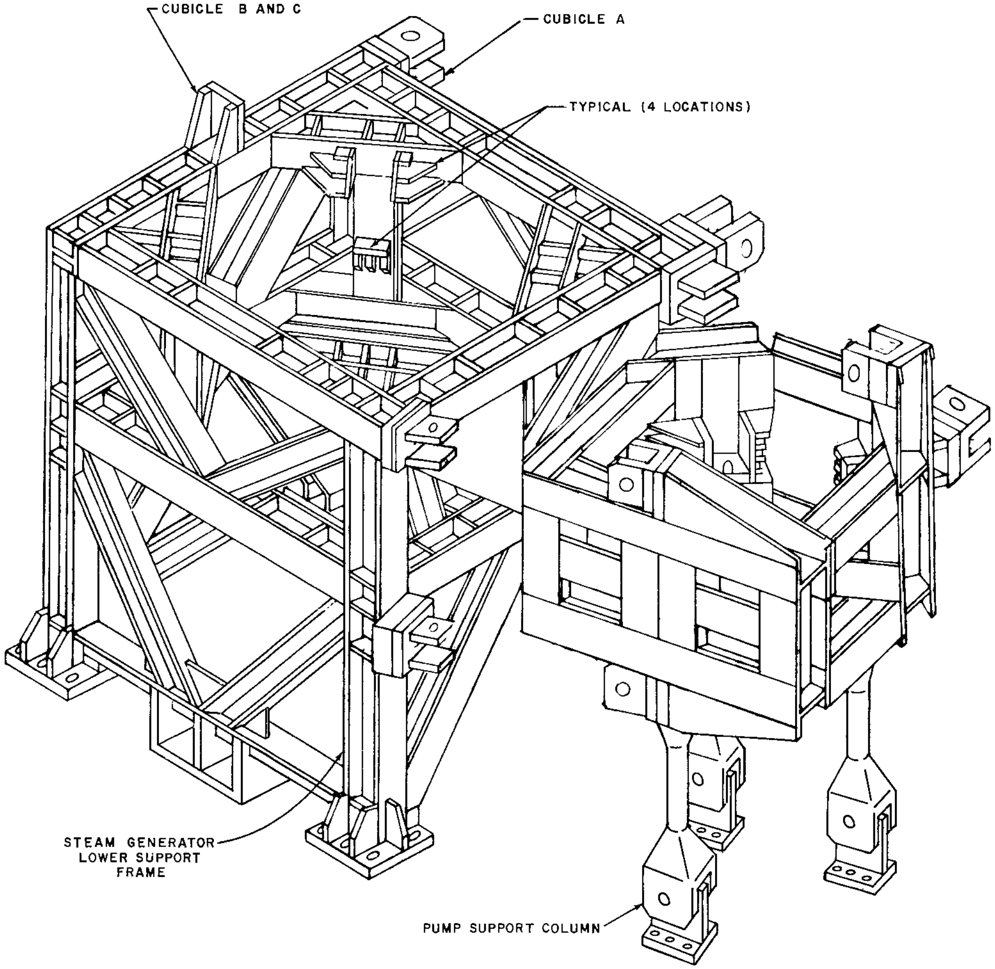
FIGURE 5.4-12

STEAM GENERATOR AND REACTOR COOLANT PUMP

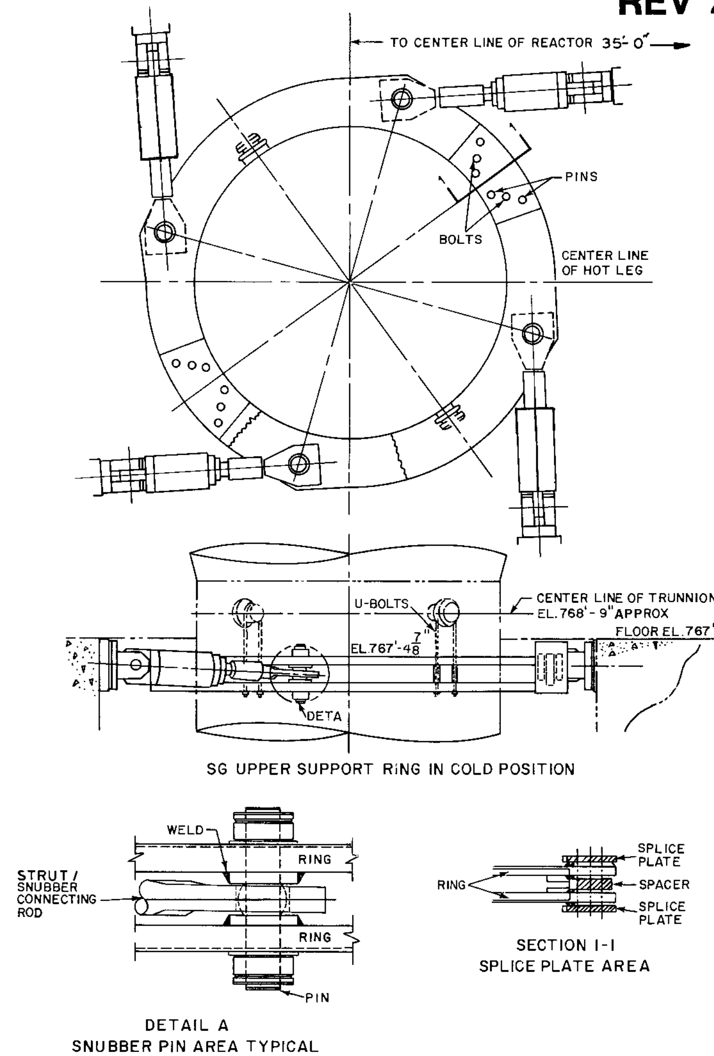
BEAVER VALLEY POWER STATION-UNIT 2

UPDATED FINAL SAFETY ANALYSIS REPORT

REV 2



STEAM GENERATOR & RCP SUPPORT FRAMES



STEAM GENERATOR UPPER SUPPORT

FIGURE 5.4-13
STEAM GENERATOR AND REACTOR COOLANT PUMP SUPPORTS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

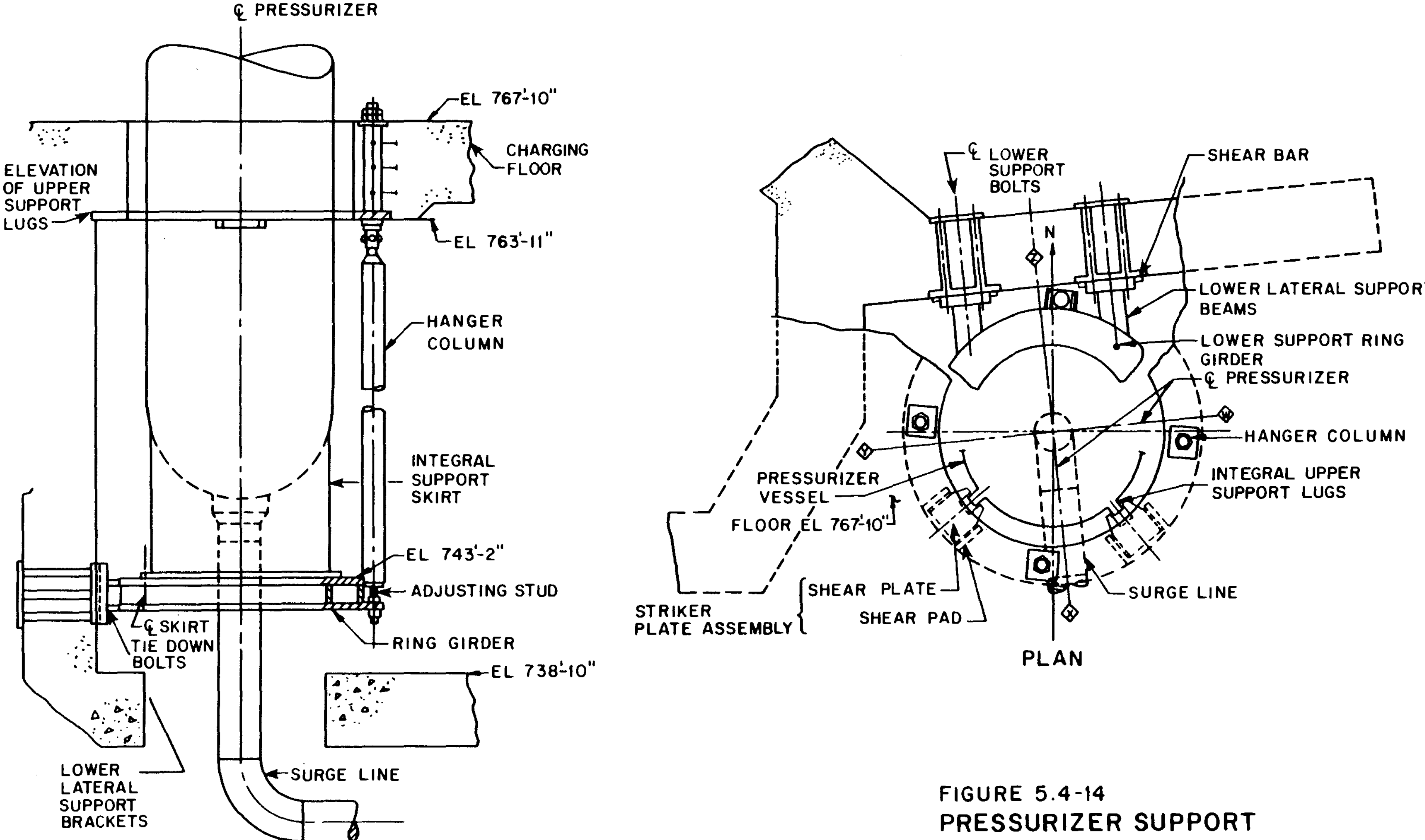


FIGURE 5.4-14
PRESSURIZER SUPPORT
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV 2

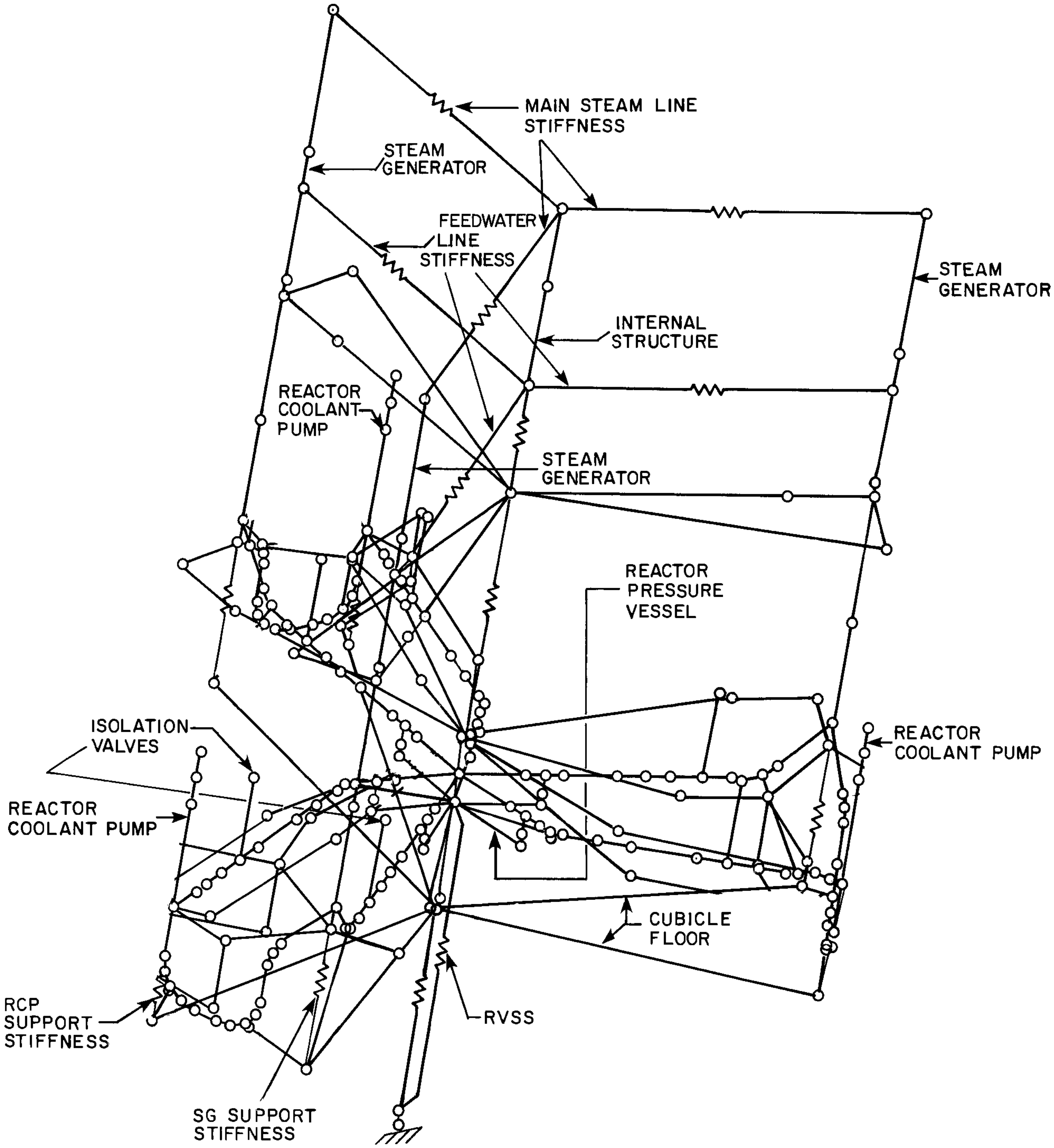
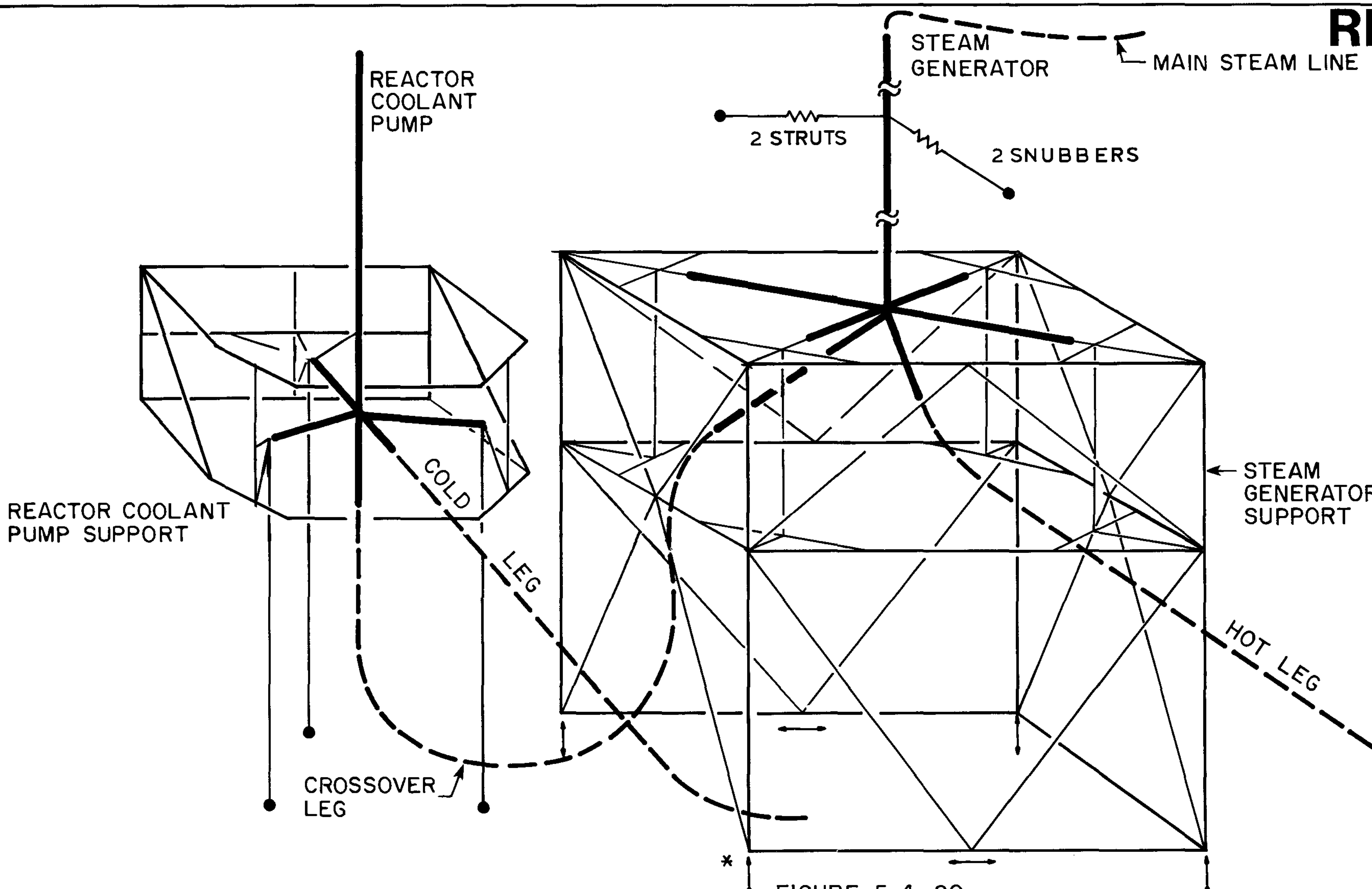


FIGURE 5.4 - 19
THREE - LOOP MODEL FOR
SEISMIC ANALYSIS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



* RESTRAINED DEGREES-OF-FREEDOM

FIGURE 5.4-20
REACTOR COOLANT PUMP / STEAM GENERATOR
DETAILED STRUCTURAL MODEL
BEAVER VALLEY POWER STATION – UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV 2

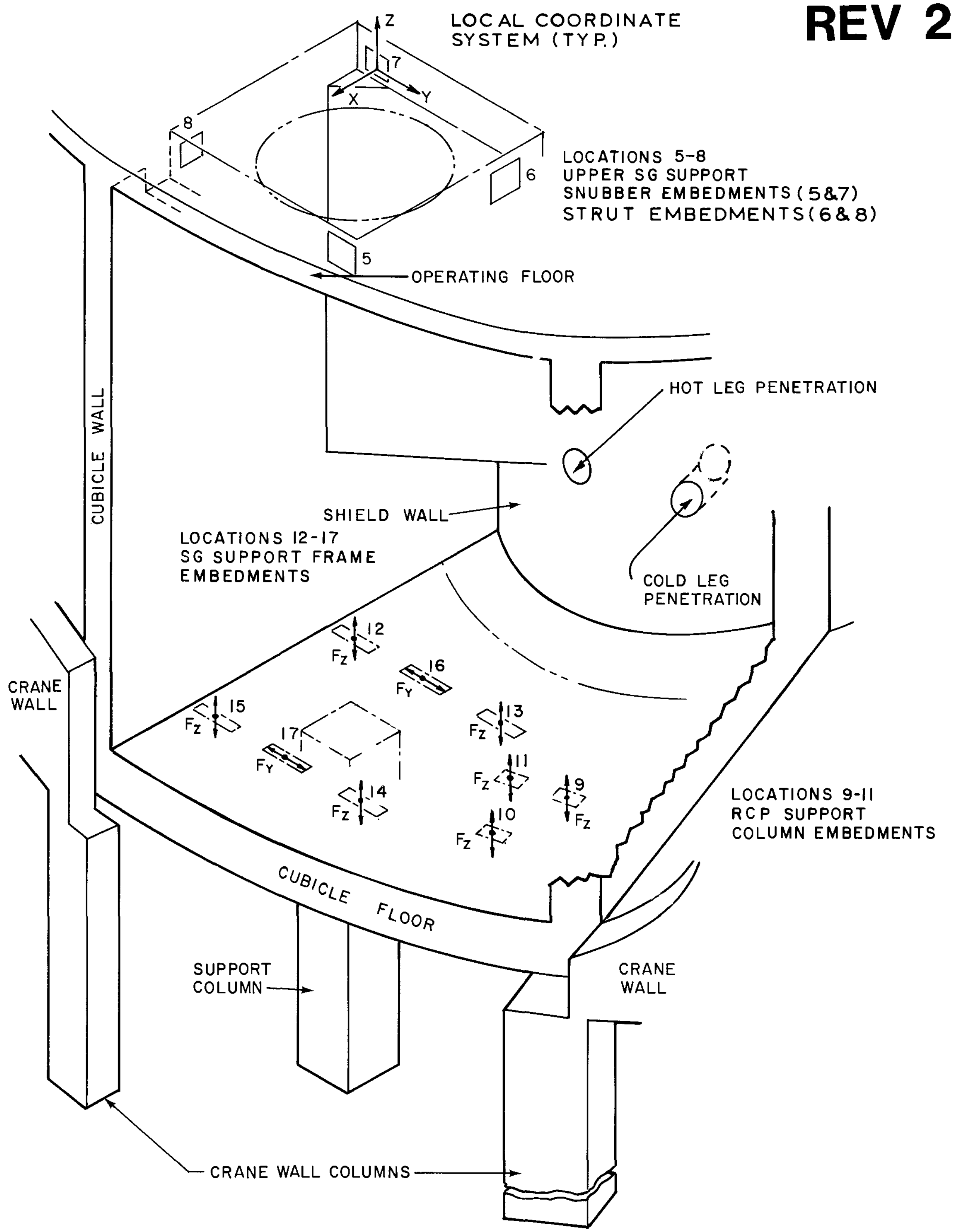


FIGURE 5.4-21
STEAM GENERATOR CUBICLE
LOADING DIAGRAM
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV 2

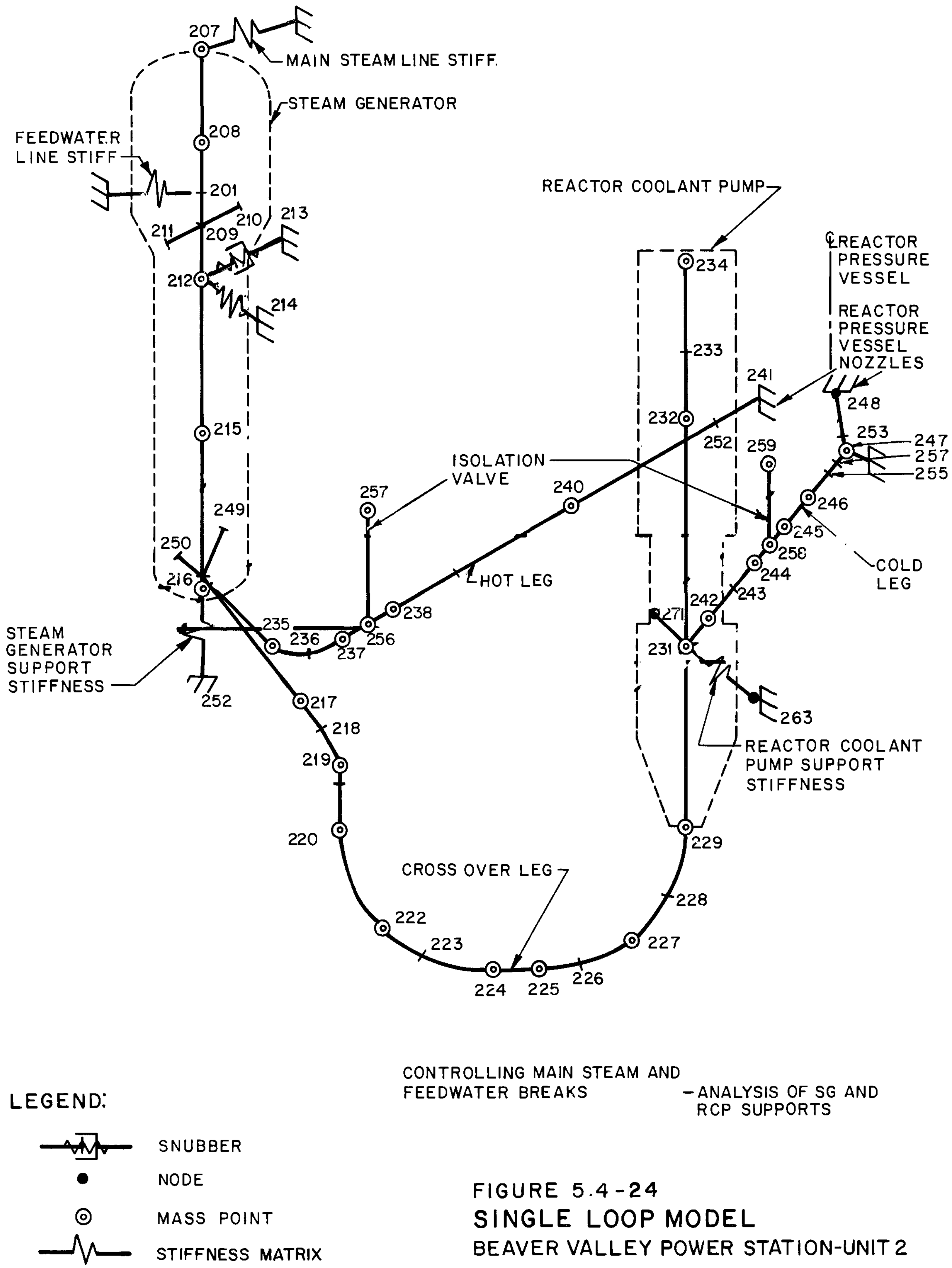


FIGURE 5.4-24
SINGLE LOOP MODEL
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

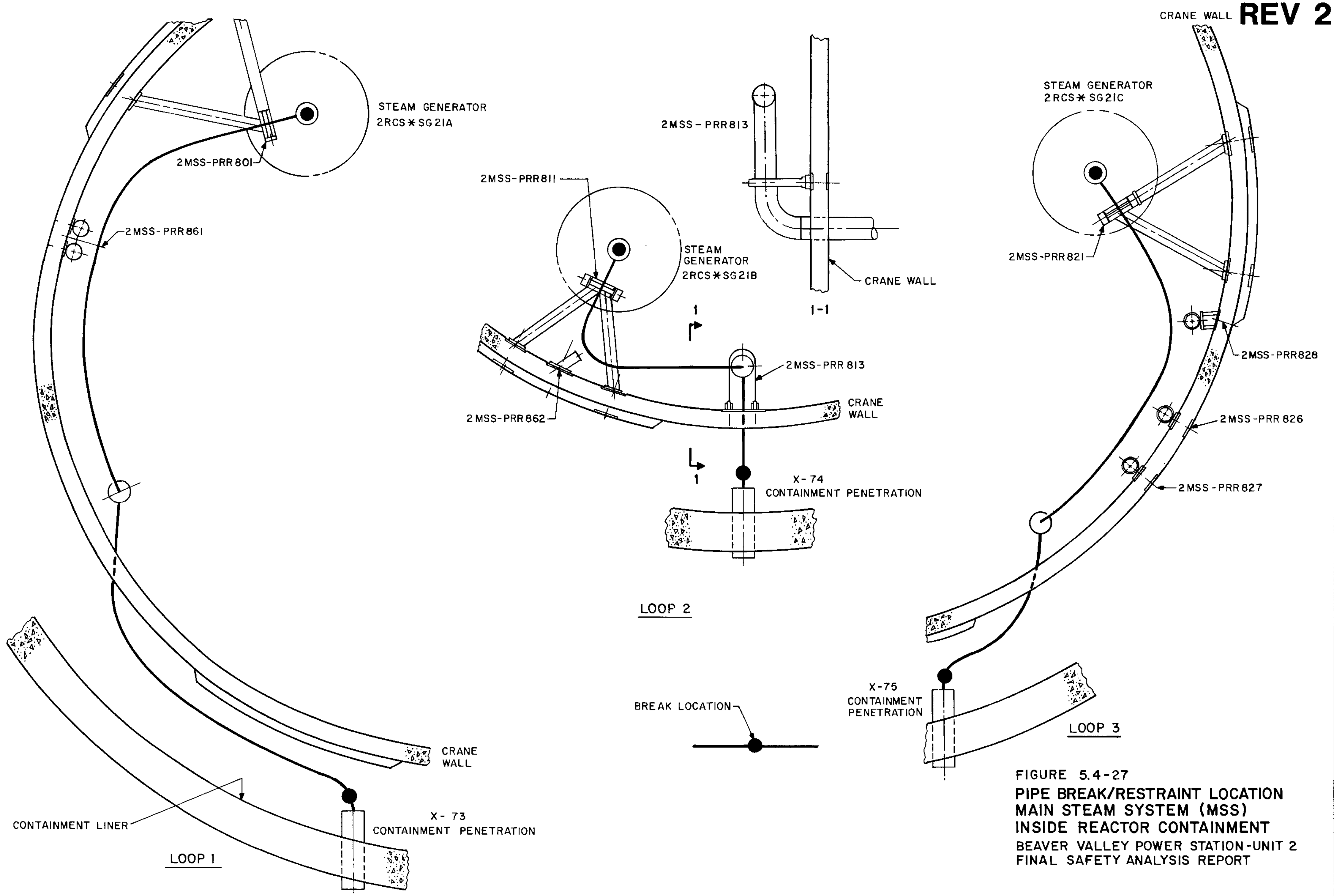


FIGURE 5.4-27

PIPE BREAK/RESTRAINT LOCATION MAIN STEAM SYSTEM (MSS) INSIDE REACTOR CONTAINMENT

BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

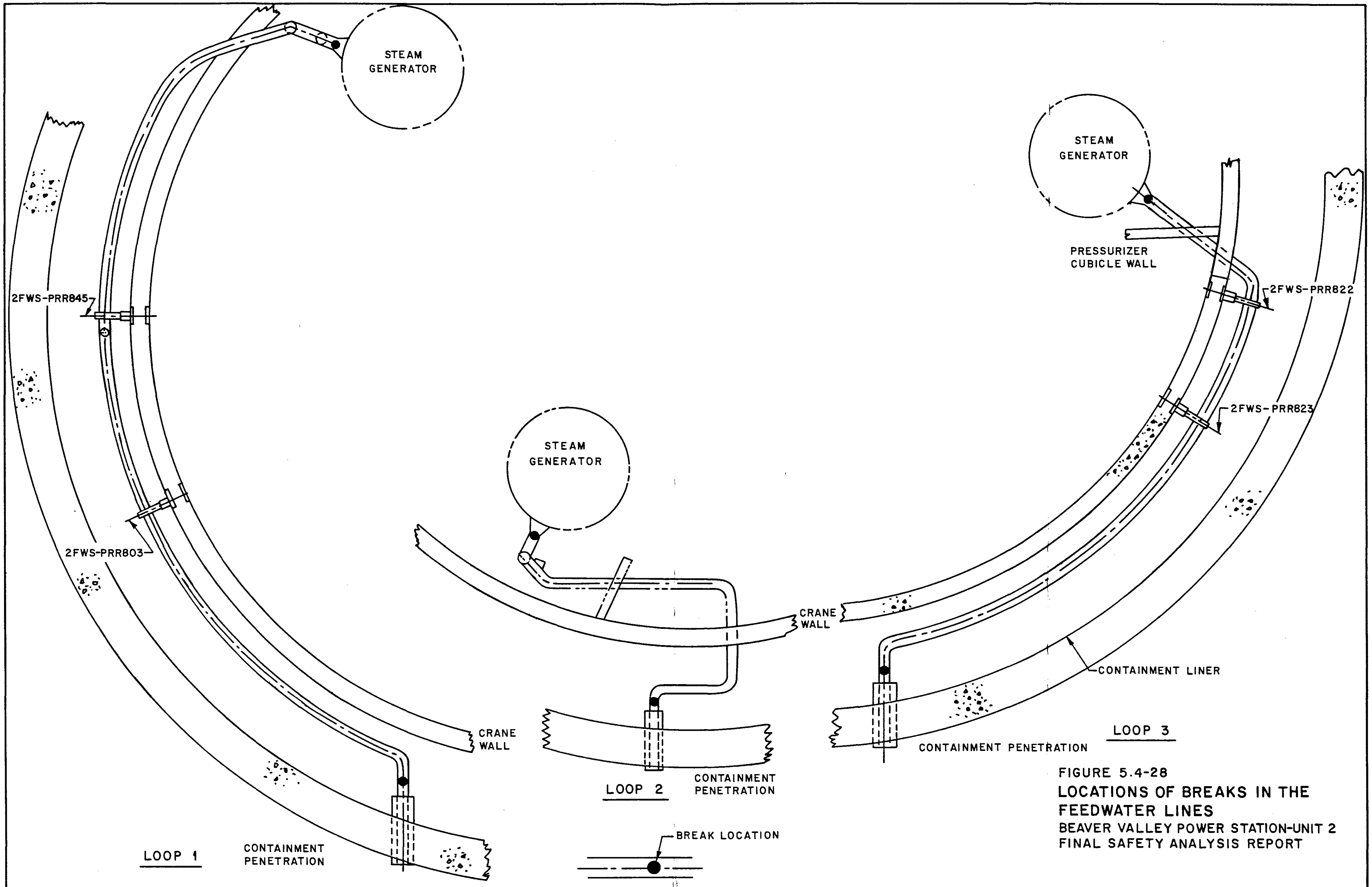
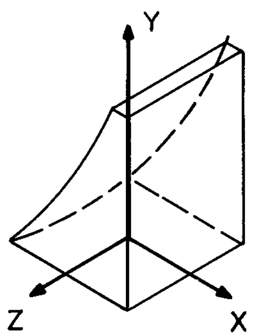


FIGURE 5.4-28
LOCATIONS OF BREAKS IN THE FEEDWATER LINES
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

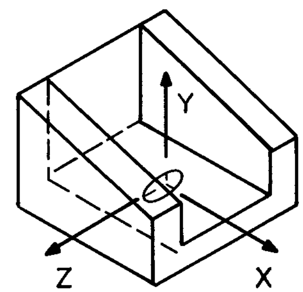
REV 2

LOAD CONDITION	F_Y	F_Z
WEIGHT	241	5
PRESSURE	24	2
THERMAL	281	82
TOTAL NORMAL	546	89
SEISMIC (OBE)	84	162
TOTAL UPSET	630	251
SEISMIC (SSE)	87	181
PIPE RUPTURE	539	625
TOTAL FAULTED	1092	740



TYPICAL STEAM GENERATOR FOOT

LOAD CONDITION	F_Y	F_Z
WEIGHT	122	0
PRESSURE	127	0
THERMAL	229	0
TOTAL NORMAL	478	0
SEISMIC (OBE)	586	37
TOTAL UPSET	1064	37
SEISMIC (SSE)	630	41
PIPE RUPTURE	822	294
TOTAL FAULTED	1514	297



TYPICAL REACTOR COOLANT PUMP FOOT

NOTES:

1. UNITS: IN, KIPS
2. ALL LOADS ARE ±
3. UPSET = NORMAL + OBE
4. FAULTED = NORMAL + $\sqrt{(SSE)^2 + (P.R.)^2}$
5. EACH LOAD ENVELOPES ALL FEET IN 3 CUBICLES

FIGURE 5.4-32
STEAM GENERATOR AND REACTOR COOLANT PUMP FOOT LOADS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

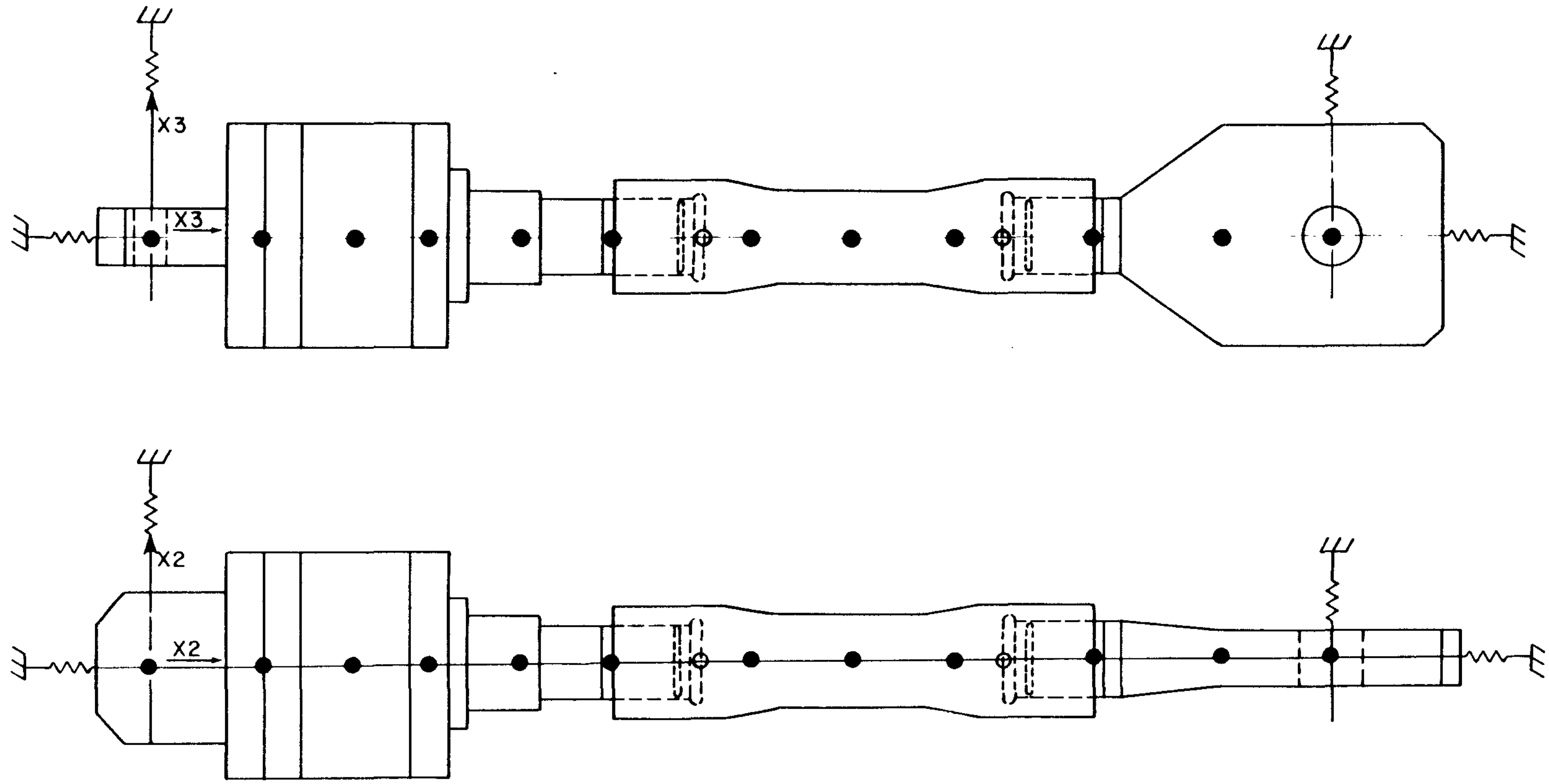


FIGURE 5.4 - 34

TYPICAL DYNAMIC MODEL OF SNUBBER TRAIN FOR SEISMIC & PIPE RUPTURE ANALYSIS

BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

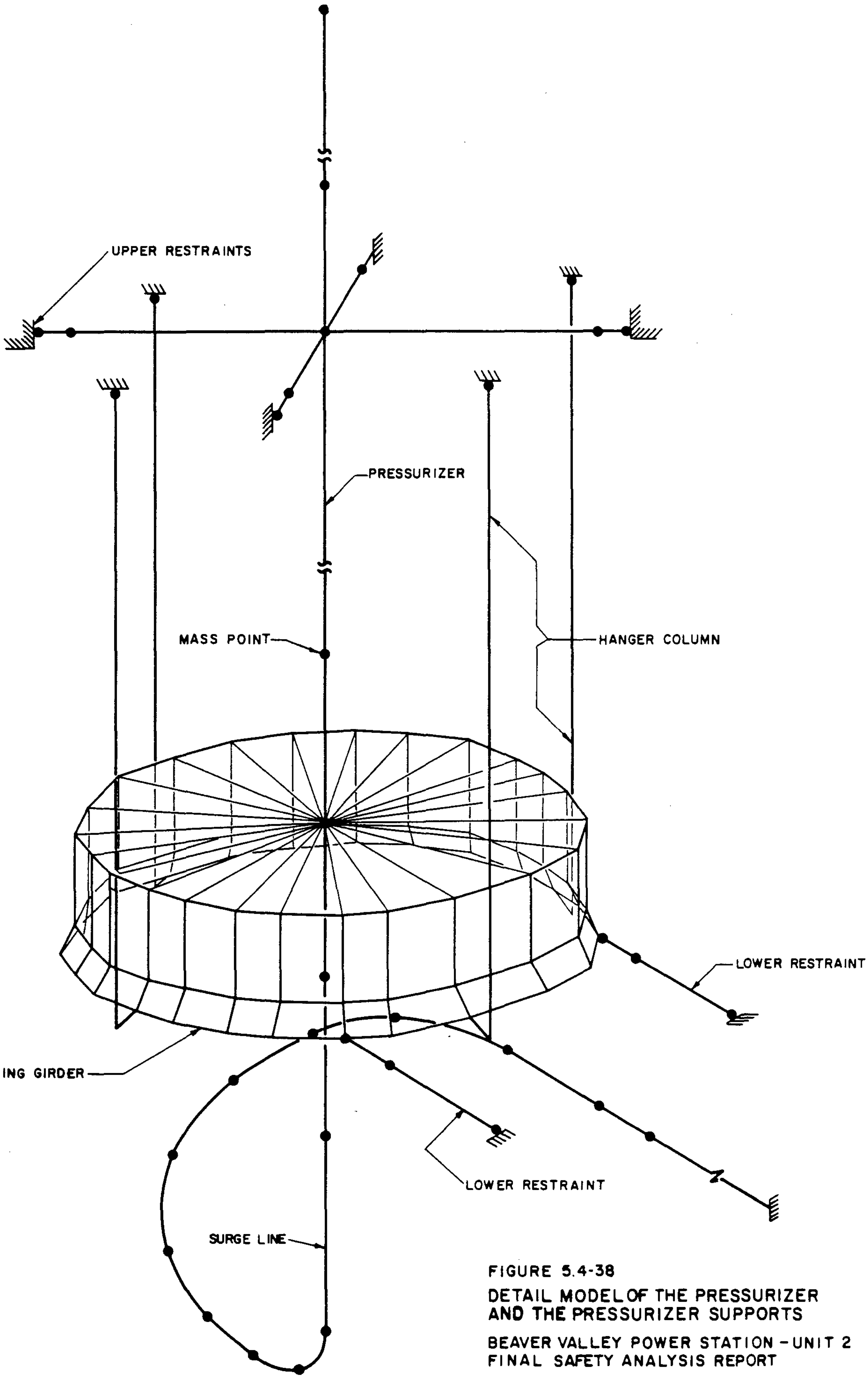


FIGURE 5.4-38

DETAIL MODEL OF THE PRESSURIZER AND THE PRESSURIZER SUPPORTS

BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

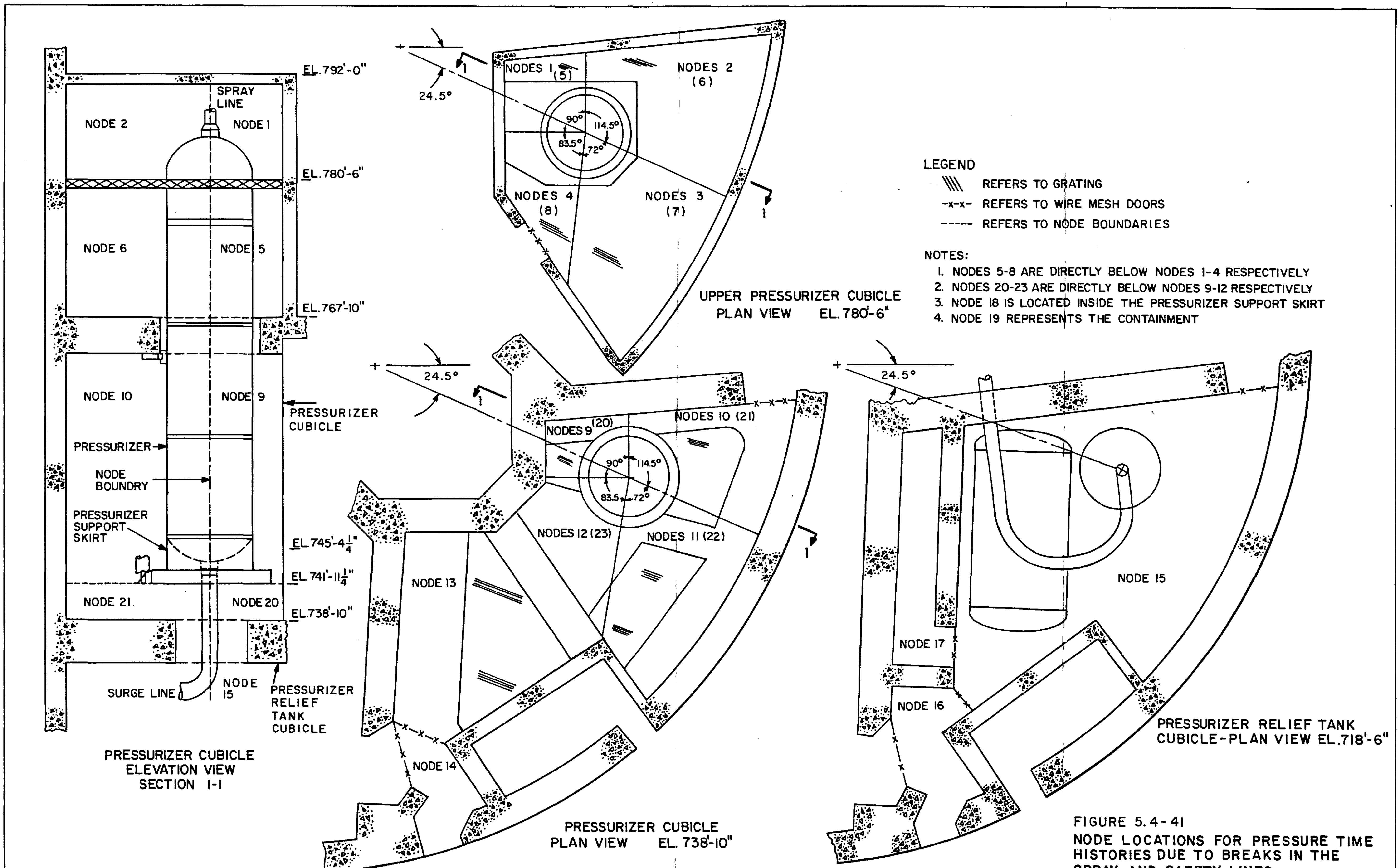
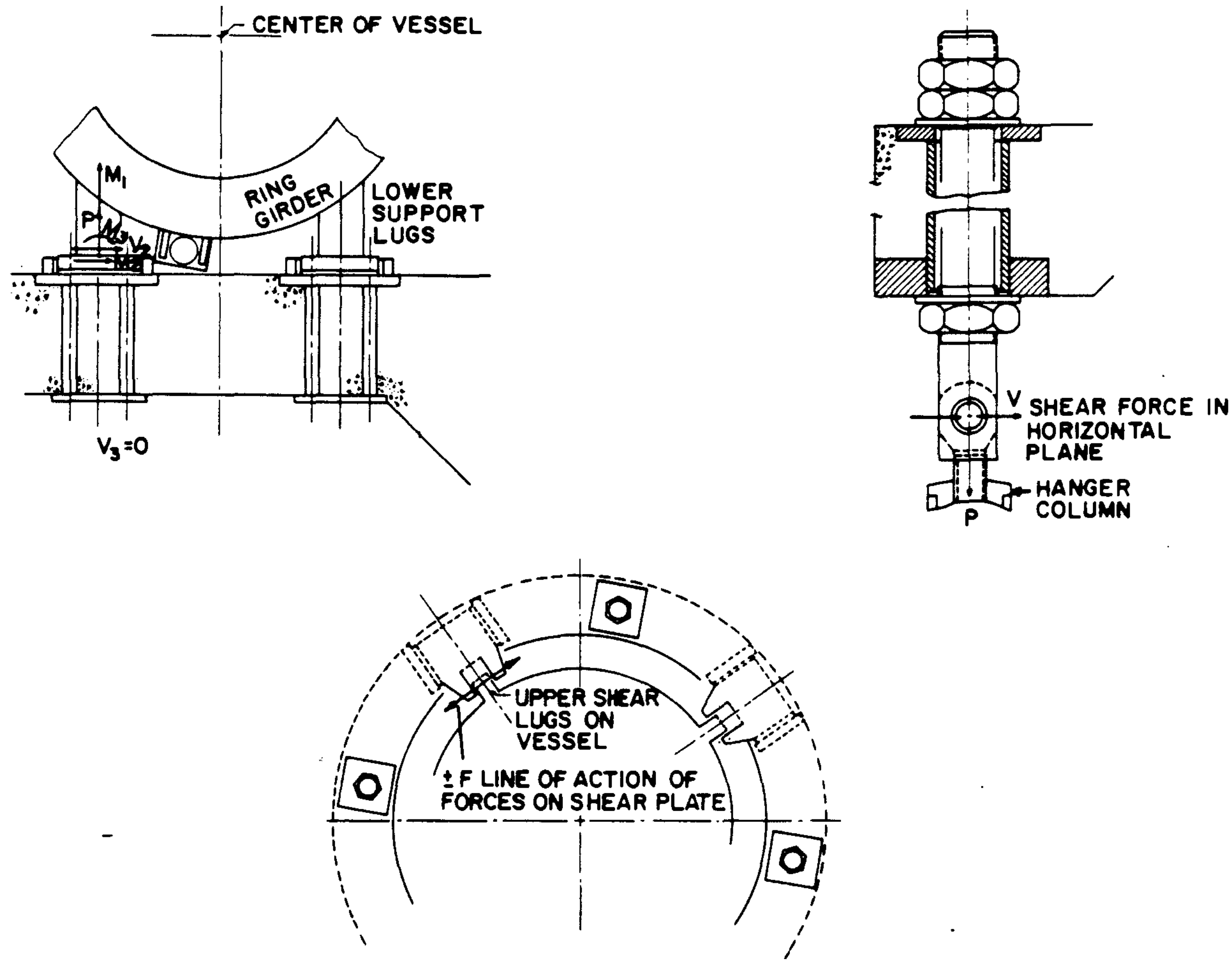


FIGURE 5.4-41
NODE LOCATIONS FOR PRESSURE TIME HISTORIES DUE TO BREAKS IN THE SPRAY, AND SAFETY LINES
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT



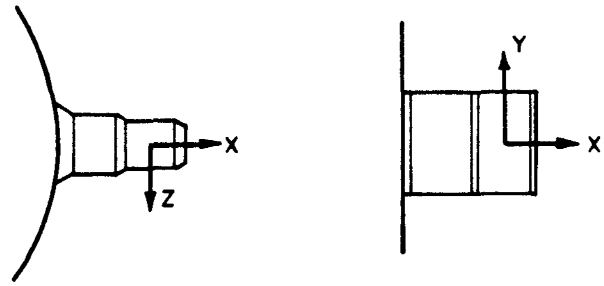
COMPONENT	CONDITION	LOADS					
		P	RESULTANT HORIZONTAL SHEAR (V)				
HANGER COLUMNS	UPSET	+83 −28	2				
	FAULTED	+200 −65	2				
		TANGENTIAL FORCE (F)					
UPPER SUPPORT LUGS	UPSET	25					
	FAULTED	165					
		P	V_2	V_3	M_1	M_2	M_3
LOWER SUPPORT LUGS	UPSET	38	19	0	69	881	274
	FAULTED	124	72	0	87	1059	820

NOTES:

1. UNITS: IN, KIPS
2. ALL LOADS ARE ± UNLESS NOTED OTHERWISE

FIGURE 5.4-42
PRESSURIZER SUPPORT EMBEDMENT LOADS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

COMPONENT	CONDITION	F_Z TANGENTIAL LOAD
UPPER SUPPORT LUGS	DEADWEIGHT	0
	SEISMIC	
	OBE	25
	SSE	25
	PIPE RUPTURE	141

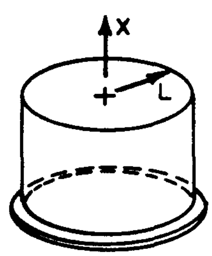


UPPER SUPPORT LUGS

COMPONENT	CONDITION	F_X VERTICAL FORCE	F_L SHEAR FORCE	M_L OVERTURNING MOMENT	M_X TORSION
SUPPORT SKIRT-VESSEL JUNCTION	DEADWEIGHT THERMAL	-215	1	160	35
	SEISMIC	7	14	896	2251
	OBE	84	41	2 565	620
	SSE	84	41	2 565	620
	PIPE RUPTURE	80	130	2 259	9613

NOTE:

1. UNITS : IN, KIPS



$L = \left[Y^2 + Z^2\right]^{\frac{1}{2}}$

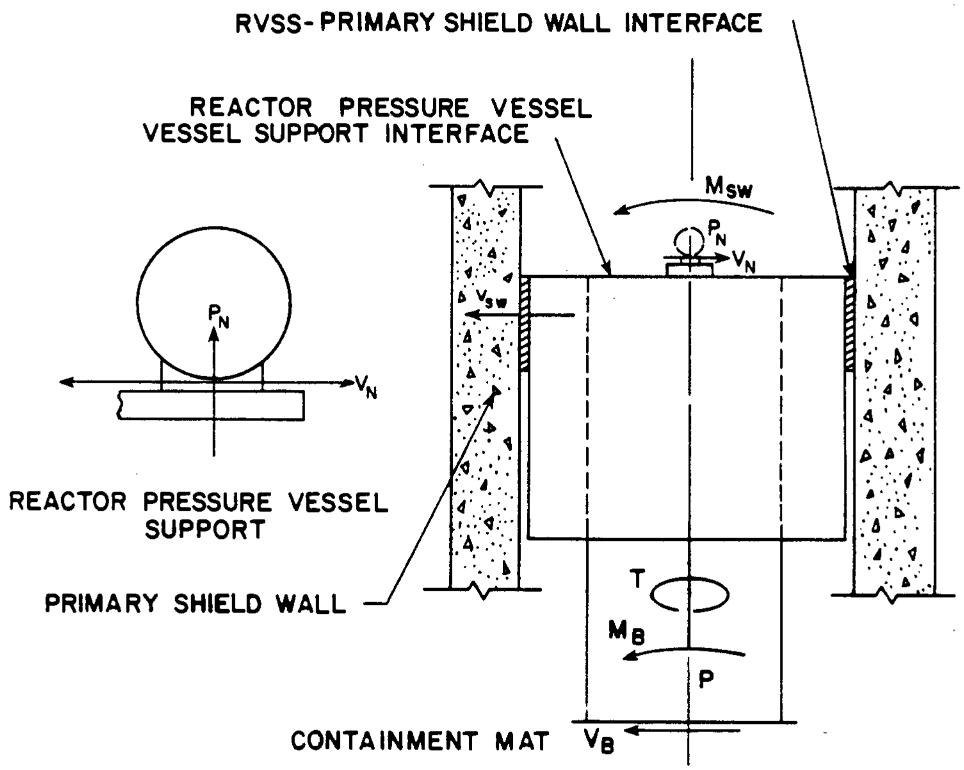
SUPPORT SKIRT-VESSEL JUNCTION

FIGURE 5.4-43
PRESSURIZER VESSEL INTERFACE LOADS AND COORDINATE SYSTEMS
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

	LOAD AT SUPPORT BASE				LOAD AT PRIMARY SHIELD WALL INTERFACE		LOAD AT REACTOR PRESSURE VESSEL INTERFACE	
	P	V_B	T	M_B	V_{SW}	M_{SW}	P_N	V_N
CONDITION TYPE	VERTICAL	SHEAR	TORSION	MOMENT	SHEAR	MOMENT	VERTICAL	SHEAR
DEADWEIGHT	+0 −2435	±10	±135	±4600	±10	±325	+0 −325	±0
SEISMIC (OBE)	± 95	± 1160	± 20,200	± 394,000	± 835	± 156,000	± 115	± 570
SEISMIC (SSE)	± 155	± 1285	± 22,800	± 435,200	± 875	± 188,000	± 135	± 645
TOTAL NORMAL OPERATING (2)	+ 95 − 2530	± 1170	± 20,335	± 398,600	± 845	± 156,325	+ 115 − 440	± 570
TOTAL FAULTED (3)	+ 155 − 2590	± 1295	± 22,935	± 439,800	± 885	± 188,325	+ 135 − 460	± 645

NOTES:

1. UNITS ARE EXPRESSED IN KIPS, INCHES
2. INCLUDES DEADWEIGHT AND SEISMIC (OBE).
3. INCLUDES DEADWEIGHT AND SEISMIC (SSE)



REACTOR VESSEL SUPPORT FORCES

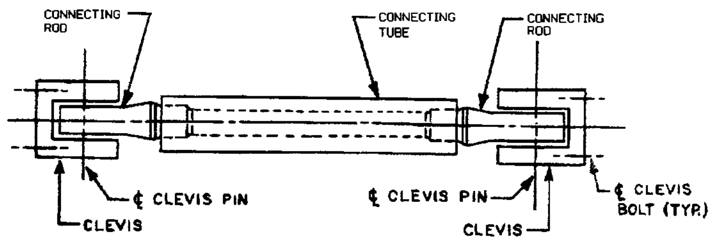
FIGURE 5.4-45
MAXIMUM DESIGN LOADS FOR REACTOR VESSEL STRUCTURAL SUPPORT
BEAVER VALLEY POWER STATION-UNIT 2
FINAL SAFETY ANALYSIS REPORT

REV. 2

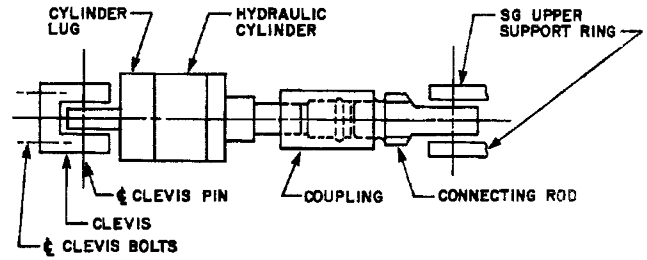
COMPONENT	MATERIAL DESIGNATION	MATERIAL STRESS (KSI) (1)	FAULTED CONDITION (2)				
			AXIAL STRESS (KSI) (TENSION or COMPRESSION)	ALLOWABLE STRESS (3) (KSI)	BENDING STRESS (KSI)	ALLOWABLE STRESS (3) (KSI)	FACTOR (4) OF SAFETY
STEAM GENERATOR UPPER STRUTS							
CONNECTING ROD	A-668-83CLM	145.0	32.9	101.5	-	-	3.1
CONNECTING TUBE	A-513-84	120.0	30.6	84	-	-	2.7
CLEVIS CLEVIS PIN CLEVIS BOLTS	SEE NOTE 5.						
STEAM GENERATOR UPPER SNUBBERS							
CONNECTING ROD	A-237 CLG	136.0	55.8	67.7	10.2	161.8	1.12
CLEVIS	A-237 CLF	112.5	21.8	59.1	48.3	88.6	1.09
CLEVIS BOLTS	A-237RC35-40	175.0	102.1	122.5	—	—	1.20
CLEVIS PIN	A-331GR4340	145.0	—	—	157.8	172.4	1.09
CYLINDER LUG	A-237 CLF	145.0	—	—	80.9	101.8	1.25
COUPLING	A-540GRB23CL3	145.0	54.8	66.7	8.0	147.2	1.16

NOTES:

1. MINIMUM SPECIFIED YIELD OR ULTIMATE AT TEMPERATURE EXCEPT FOR THE CONNECTING ROD OF THE SG UPPER SNUBBERS WHICH IS BASED ON MILL TEST REPORT.
2. EVEN THOUGH THE ALLOWABLE STRESSES ARE LOWER FOR THE NORMAL OPERATING CONDITIONS, THE CORRESPONDING DESIGN LOADS WERE SIGNIFICANTLY LOWER, THUS MAKING THE FAULTED CONDITION THE CRITICAL DESIGN CONDITION.
3. THE ALLOWABLE STRESSES ARE BASED ON TABLE 5.4-21.
4. THE FACTORS OF SAFETY FOR THE STEAM GENERATOR UPPER SNUBBERS ARE BASED ON A MAIN STEAM PIPE RUPTURE + DEADWEIGHT + SSE DESIGN BASIS. THE RESULTS ARE VERY CONSERVATIVE AND ARE PRESENTED FOR INFORMATION ONLY. THE UPPER STRUT FACTORS OF SAFETY ARE BASED ON FAULTED LOADS SHOWN IN TABLE 5.4-24
5. THESE COMPONENTS WERE DESIGNED SIMILARLY TO THE ONES ON THE UPPER SNUBBER, SNUBBERS. UPPER SUPPORT SNUBBER LOADS WERE MORE CONSERVATIVE AND GOVERNED THE DESIGN.



STEAM GENERATOR UPPER SUPPORT STRUT ASSEMBLIES



STEAM GENERATOR UPPER SUPPORT SNUBBER ASSEMBLIES

FIGURE 5.4-46
FACTORS OF SAFETY FOR THE STEAM GENERATOR UPPER SUPPORT STRUT AND UPPER SUPPORT SNUBBER ASSEMBLIES
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

	HANGER COLUMN			UPPER LUG RESTRAINT
LOAD(3) / CONDITION	AXIAL	MOMENT	SHEAR	SHEAR
UPSET	84	52	2	25
FAULTED *	120	52	2	165

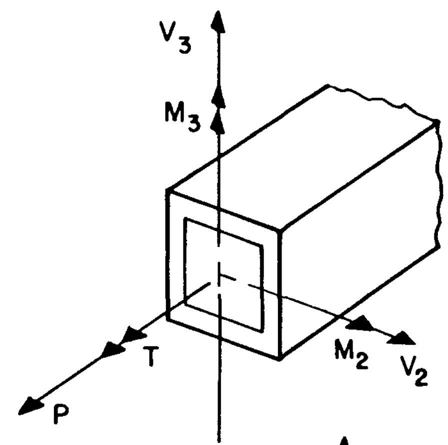
	RING GIRDER					
LOAD(3) / CONDITION	P	V_2	V_3	M_2	M_3	T
UPSET	225	69	72	2690	864	820
FAULTED *	320	129	99	3262	2032	1134

	LOWER LATERAL RESTRAINT					
LOAD (3) / CONDITION	P	V_2	V_3	M_2	M_3	T
UPSET	37	20	0	881	274	69
FAULTED *	124	72	0	1059	820	193

NOTES:

1. UNITS ARE EXPRESSED IN KIPS, INCHES.
2. REFER TO FIG. 5.4.14-34 FOR RELATIVE LOCATION OF ELEMENT.
3. ALL LOADS ARE ± UNLESS NOTED OTHERWISE.

* LOADS BASED ON SPRAY LINE PIPE BREAKS



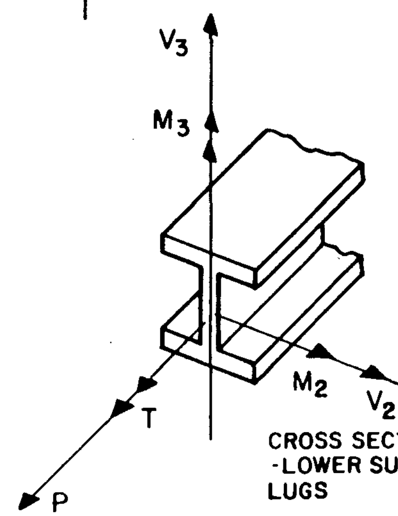


FIGURE 5.4-47
MAXIMUM DESIGN LOADS FOR PRESSURIZER SUPPORT
BEAVER VALLEY POWER STATION - UNIT 2
FINAL SAFETY ANALYSIS REPORT

APPENDIX 5A

COLD SHUTDOWN CAPABILITY

APPENDIX 5A

COLD SHUTDOWN CAPABILITY

5A.1 GENERAL

The ability to bring a plant to safe shutdown conditions following any postulated event has been the subject of several licensing guidance documents in recent years. These documents have attempted to provide the designer with adequate guidance in incorporating appropriate systems, components, and procedures such that the plant can reliably reach and maintain safe shutdown conditions.

This appendix is written to display the degree of compliance of the BVPS-2 design with the requirements as outlined in Branch Technical Position (BTP) RSB 5-1, Revision 2. Table 5A-1 provides a brief line-by-line comparison of the BVPS-2 design with the requirements listed in Table 1 of the BTP.

5A.2 DESIGN APPROACH

While the safe shutdown design basis for BVPS-2 is hot standby, the cold shutdown capability of the plant has been evaluated in order to demonstrate how the plant can achieve cold shutdown conditions following a safe shutdown earthquake, assuming loss-of-offsite power and the most limiting single failure. Under such conditions, the plant is capable of achieving residual heat removal system (RHRS) initiation conditions (approximately 350°F, 400 psig) within 36 hours.

To achieve and maintain cold shutdown, the following key functions must be performed:

1. Residual heat removal,
2. Boration and inventory control,
3. Depressurization, and
4. Plant status monitoring (instrumentation and control).

5A.2.1 Residual Heat Removal

Following the insertion of the control rods, the plant is stabilized at hot standby conditions until cooldown is initiated. The residual heat removal (RHR) function is accomplished in two stages from hot standby to cold shutdown.

During the first stage of cooldown, heat removal is accomplished via the steam generators, the auxiliary feedwater system, and the steam line atmospheric dump valves (ADVs). Should the reactor

coolant pumps (RCPs) be unavailable, transport of the residual heat from the core to the steam generators occurs by natural circulation.

Feedwater to the steam generators is pumped from the primary plant demineralized water storage tank (PPDWST) by the redundant auxiliary feedwater pumps. The PPDWST is maintained with at least 130,000 gallons of usable volume, sufficient for maintaining hot standby for at least 9 hours without makeup to the tank. Backup is provided by the 600,000-gallon demineralized water storage tank (DWST), which contains up to 552,000 gallons that are transferable to the PPDWST. Combined, these tanks have adequate storage capacity to maintain hot standby conditions in excess of 72 hours. Additionally, supply connections from the service water system (SWS) are available should they be required.

Each steam generator has a single steam line ADV sized such that only two of three steam generators and steam line ADVs are required for cooldown. An additional atmospheric steam release valve, the residual heat release valve (2SVS*HCV104), is provided on a common header from all three steam generators. The electric power for the three individual steam steam line ADVs is provided by one Class lE bus while the common valve receives its power from the other Class lE bus.

Following cooldown to residual heat removal system (RHRS) initiation conditions, the second stage of RHR begins. The RHRS is brought into operation by accessing one or both of the redundant RHR trains. Start-up of the RHRS includes a warmup period during which time reactor coolant flow through the heat exchangers is limited to minimize thermal shock. This flow is regulated by flow control valves downstream of the heat exchangers with total return flow provided by the control valves in the bypass lines around the heat exchangers. Should any of these control valves fail, RHR flow may be controlled through use of only one RHRS train and/or operator control of the RHR pump(s).

Residual heat is transferred during this stage from the reactor core through the RHRS to the component cooling water system (CCWS) and then, in turn, to the SWS.

5A.2.2 Boration and Inventory Control

Injection of boric acid into the reactor coolant system (RCS) is required to offset xenon decay and the reactivity change occurring through cooldown. Four weight percent boric acid is pumped from the boric acid tanks to the suction of the centrifugal charging pumps by means of the boric acid transfer pumps. Should this source of boric acid be unavailable, borated water from the refueling water storage tank (RWST) can be used.

The borated water is then injected into the RCS via the normal charging line and the RCP seals. A backup means for injection involves the use of either of the redundant throttling paths within the emergency core cooling system (ECCS). Each of the ECCS paths contains a solenoid operated throttling valve that permits variable control of the charging rate from the main control room.

To accommodate the borated water addition to the RCS, letdown is provided via the normal letdown line up to a crossconnect outside containment which bypasses the boron recovery system and directs the letdown to the coolant recovery tanks of BVPS-1. Electric power to the solenoids for the air-operated valves in the letdown line and motor-operated valves (MOVs) in the crossconnect line can be supplied from the emergency diesel generators. The air-operated valves normally receive air from the containment instrument air compressors. The backup air supply is provided by the service air compressors. In addition, the service air compressors can receive power from the single, onsite nonsafety-related diesel generator should loss-of-offsite power occur.

An alternate means of letdown is provided via the reactor vessel head vent line to the pressurizer relief tank (PRT). Throttling control of the letdown is provided by either of two parallel remote manual hand control valves.

The reactor vessel head vent line also provides a means for venting gases from the vessel head region. Intermittent use of this path to vent any gases augments RCS pressure control during a natural circulation cooldown.

5A.2.3 Depressurization

Following boration, the RCS must be cooled down, then depressurized to RHRs initiation conditions. Should it be available, depressurization will be accomplished by use of the pressurizer auxiliary spray valve and the normal charging line. Another means of depressurization involves the use of the pressurizer power operated relief valves. Three valves in parallel are provided with any one being capable of providing the depressurization function.

To prevent water injection from the accumulators during the depressurization process, the accumulators must be isolated from the RCS. Each accumulator is equipped with a normally open MOV in its discharge line. At approximately 1000 psi, power to these valves will be restored and the valves closed. Should a discharge valve fail to close, the affected accumulator can be vented to the containment via redundant vent valves both on the individual accumulator itself and in the common nitrogen fill/vent header.

5A.2.4 Plant Status Monitoring (Instrumentation and Control)

Safety related instrumentation is available in the control room to monitor the key functions associated with achieving cold shutdown. This instrumentation is detailed in Table 7.5-1 and includes the following:

1. Reactor coolant system wide range temperature,

2. Reactor coolant system wide range pressure,

3. Pressurizer water level,

4. Steam generator water level,

5. Steam line pressure (per steam line),

6. Primary plant demineralized water storage level,

7. Boric acid tank level (per tank),

8. Refueling water storage tank level, and

9. Individual valve position indication.

This instrumentation is sufficient to monitor the key functions associated with cold shutdown and to maintain the RCS within the desired pressure, temperature, and inventory relationships.

5A.3 PERFORMANCE EVALUATION

5A.3.1 Residual Heat Removal

Three reactor coolant loops and steam generators are provided, only one of which is required to stabilize the plant at hot standby conditions with natural circulation cooling. For cooldown to RHRS initiation conditions, two of the three steam line ADVs would be required. To allow for single failure, an additional valve has been located in a common header from the three steam generators. This valve, the residual heat release valve, is larger than the individual steam line ADVs such that with loss of the Class 1E bus powering the individual steam line ADVs the common valve has adequate capacity to permit cooldown to RHRS initiation.

The individual steam line ADVs are loaded onto one Class 1E bus while the common valve is loaded onto the other Class 1E bus (Section 10.3).

Feedwater to the steam generators is provided by the safety grade auxiliary feedwater system with the condensate being drawn from the PPDWST. This tank is Seismic Category I and is protected from tornadoes, missiles, and pipe breaks. Nonsafety-related piping entering the tank is located such that pipe failure will not permit water draindown past the level required for emergency feedwater usage. The tank's minimum usable capacity of 130,000 gallons is sufficient for at least 9 hours at hot standby.

Additional condensate for cold shutdown is normally available from the 600,000 gallon capacity DWST, which contains up to 552,000 gallons of water which is transferable to the PPDWST. An 8-inch gravity flow line with a normally closed manual valve and check valve exists between the two tanks. Should the backup tank be unavailable, piping cross-connections to the Seismic Category I SWS are provided. These piping cross-connections are in the safeguards building and located on the suction of the auxiliary feedwater pumps (Section 9.2.3).

Following cooldown and depressurization to RHRS initiation conditions, the RHRS is brought into operation. Two redundant RHR trains are provided, either of which is capable of cooling the RCS to cold shutdown conditions. Startup of a RHR train is accomplished by opening two series isolation valves in the suction line to the RHR pump and a single isolation valve in the discharge line from each pump to the RCS. A discussion of the reliability considerations for these valves is provided in Sections 5.4.7.2.6 and 7.6.2.

Cooling water to the RHR heat exchangers is provided by the CCWS. Individual valves in the component cooling water supply lines are provided with power from Class 1E buses (Section 9.2.2.1).

Flow control through each RHR train is provided by flow control valves downstream of the RHR heat exchangers. Should these control grade valves fail, orifices are provided in the discharge lines to the RCS to prevent RHR pump runout. In addition, minimization of thermal shock to the RHR heat exchangers may be controlled through use of only one RHR train and/or operator control of the RHR pumps.

5A.3.2 Boration and Inventory Control

Boric acid to offset xenon decay and the reactivity change occurring through cooldown is provided by the boric acid tanks. Two Seismic Category I tanks are provided with only one being required. Four weight percent boric acid from either of the tanks is gravity fed to either of the two boric acid transfer pumps. These pumps are Seismic Category I and powered from the Class 1E buses.

Discharge from the boric acid transfer pumps is directed to the suction of the centrifugal charging pumps through either of two paths. Each path contains a single isolation valve powered from a Class 1E bus. The piping from the boric acid tanks to the centrifugal charging pumps is Seismic Category I.

An alternate source of borated water is the RWST. Redundant paths from this tank, each containing a single Class 1E powered isolation valve, are provided. The boric acid is injected into the RCS via the normal charging line and reactor coolant pump seals. Both of these pathways contain air-operated throttling control valves. Should these control valves fail, the boric acid can be directed to the RCS by either of two one-inch throttling paths in the ECCS. Isolation and throttling valves in these paths are powered from Class 1E buses.

Letdown capability is provided by the normal and excess letdown lines to the chemical and volume control system and the reactor vessel head vent line. The normal letdown line directs letdown through a crossconnect line outside containment to the coolant recovery tanks on BVPS-1. Should offsite power be lost, the isolation valves in

this line can be powered from the emergency diesel generators. Normally, the air-operated valves receive air from the containment instrument air compressors, and are backed up by the service air compressors. The valves in the excess letdown line, unlike the normal letdown line, cannot be powered from the single, onsite nonsafety-related diesel generator.

If both the normal and excess letdown lines are unavailable, letdown may be accomplished by means of the safety grade reactor vessel head vent system Class 1E solenoid valves, in parallel, which permit letdown to the PRT. A detailed discussion of the head vent system is provided in Section 5.4.15.

5A.3.3 Depressurization

Should offsite power be available, the RCS may be depressurized by means of the pressurizer normal spray valves. The auxiliary spray valve, in conjunction with the normal charging line, provides this function in the event of a loss-of-offsite power. The auxiliary spray valve is a motor-operated globe valve which can be powered from the single, onsite nonsafety-related diesel generator.

If the normal and auxiliary spray valves are unavailable, the pressurizer PORVs may be used for RCS depressurization. Three safety grade PORVs are provided with only one required. The PORVs are electric solenoid operated, Seismic Category I, and are powered from the Class 1E buses. A detailed discussion of the pressurizer PORVs is provided in Section 5.4.13.

Tables for Appendix 5A

TABLE 5A-1
COMPLIANCE COMPARISON WITH BRANCH TECHNICAL POSITION RSB 5-1

Design Requirements of BTP RSB 5-1	Process and [System or Component]	Possible Solution for Full Compliance	Recommended Implementation for Class 2 plants*	Degree of BVPS-2 Compliance**
I. Functional requirements for taking to cold shutdown a. Capability using only safety grade systems b. Capability with either only onsite or only offsite power and with single failure (limited action outside control room to meet single failure) c. Reasonable time for cooldown assuming most limiting single failure and only offsite or only onsite power	Long-term cooling [RHR drop line]	Provide double drop line (or valves in parallel) to prevent valve failure from stopping RHR cooling function. (Note: This requirement in conjunction with meeting effects of single failure for long-term cooling and isolation requirements involves increased number of independent power supplies and possibly more than four valves.)	Compliance will not be required if it can be shown that correction for single failure by manual actions inside or outside of containment or return to hot standby until manual actions (or repairs) are found to be acceptable for the individual plant.	Two drop lines, each containing two normally closed valves in series are provided. Limited manual action would be required to overcome loss of a power train. (Section 4.5.7.2.6 and 7.6.2)
	Heat removal and RCS circulation during cool-down to cold shutdown. (Note: Need SG cooling to maintain RCS circu-lation even after RHRS in operation when under natural circulation [steam dump valves.]	Provide safety-grade dump valves, operators, and power supply, etc so that manual action should not be required after SSE except to meet single failure.	Compliance required.	Complies - Atmospheric dump valves and residual heat release valve are safety grade, Class 1E (Section 10.3).
	Depressurization [Pressurizer auxiliary spray or power-operated relief valves.]	Provide upgrading and additional valves to ensure operation of auxiliary pres-surizer spray using only safety-grade subsystem meeting	Compliance will not be required if a) dependence on manual actions inside containment after SSE or single failure or b) remaining at hot standby	Complies. Normal depressurization is via pressurizer auxiliary spray with pressurizer PORVs

TABLE 5A-1 (Cont)

Design Requirements of BTP RSB 5-1	Process and [System or Component]	Possible Solution for Full Compliance	Recommended Implementation for Class 2 plants*	Degree of BVPS-2 Compliance**
		single failure. Possible alternative may involve using pressurizer PORVs which have been upgraded. Meet SSE and single failure without manual operation inside containment.	until manual actions or repairs are complete and are found to be acceptable for the individual plant.	as backup. (Sections 5.4.7, 5.4.13, 9.3.4, 9.3-21 through 9.3-25, and Figure 5.1-1)
	Boration for cold shutdown [CVCS and boron sampling]	Provide procedure and upgrading where necessary such that boration to cold shutdown concentration meets the requirements of I. Solution could range from (1) upgrading and adding valves to have both letdown and charging paths safety grade and meet single failure to (2) use of backup procedures involving less cost. For example, boration without letdown may be acceptable and eliminate need for upgrading letdown path. Use of ECCS for injection of borated water may also be acceptable. Need surveillance of boron concentration (boronometer and/or sampling). Limited operator action inside or outside of containment if justified.	Same as above	Complies. Boration is accomplished by use of the boric acid tanks, the centrifugal charg-ing pumps and the normal charging and reactor coolant pump seal injection lines. A backup source of boric acid is the RWST. Redundant throttling valves for boric acid injection are provided in the ECCS. Safety grade letdown capability is provided by the reactor vessel head vent system. Surveillance of boron concentra-tion is by samples drawn from each reactor coolant leg (Sections 5.4.7, 5.4.15, 6.3.

TABLE 5A-1 (Cont)

Design Requirements of BTP RSB 5-1	Process and [System or Component]	Possible Solution for Full Compliance	Recommended Implementation for Class 2 plants*	Degree of BVPS-2 Compliance**
				9.3.2.1, and 9.3.4 and Figures 6.3-1 and 6.3-2.)
II. Residual heat removal system isolation	Residual heat removal system	Comply with one of allowable arrangements given.	Compliance required. (Plants normally meet the requirement under existing SRP, Section 5.4.7)	Complies. (Sections 5.4.7.2 and 7.6.2).
III. Residual heat removal system pressure relief Collect and contain relief discharge	Residual heat removal system	Determine piping, etc, needed to meet requirement and provide in design.	Compliance will not be required if it is shown that adequate alternate methods of disposing of discharge are available.	Complies. Residual heat removal pump suction relief valve discharge is piped to the PRT. (Section 5.4.7.2.4 and Figure 5.4-5.)
V. Test requirement Meet R.G. 1.68 for PWRs, test plus analysis for cooldown under natural circulation to confirm adequate mixing and cooldown within limits specified in Emergency Operating Procedures.		Run tests and confirming analysis to meet requirement.	Compliance required.	Meets the intent of R.G. 1.68. Test data and analysis for a plant similar in design to BVPS-2 has verified adequate mixing and cooldown under natural circulation conditions.

TABLE 5A-1 (Cont)

Design Requirements of BTP RSB 5-1	Process and [System or Component]	Possible Solution for Full Compliance	Recommended Implementation for Class 2 plants*	Degree of BVPS-2 Compliance**
VI. Operational procedure Meet R.G. 1.33. For PWRs, include specific procedures and information for cooldown under natural circulation		Develop procedures and information from tests and analysis.	Compliance required.	Generic procedures as developed by the Westinghouse Owners Group will be used as the basis for plant-specific procedures.
VII. Auxiliary Feedwater Supply Seismic Category I supply for auxiliary feedwater for at least four hours at hot shutdown plus cooldown to residual heat removal cut-in based on longest time for only onsite or only offsite power and assumed single failure.	Emergency feedwater supply	From tests and analysis obtained conservative estimate of auxiliary feedwater supply to meet requirement and provide Seismic Category I supply.	Compliance will not be required if it is shown that an adequate alternate Seismic Category I source is available.	The PPDWST is maintained with at least 130,000 gallons usable volume which is adequate for at least 9 hours at hot standby prior to aligning a secondary supply for the auxiliary feedwater system. Normal backup is provided by the 600,000 gallon demineralized water storage tank and Seismic Category I backup is provided by the SWS. (Sections 9.2.3 and 10.4.9 and Figure 10.4-24).

NOTES:

* The implementation for Class 2 plants does not result in a major impact while providing additional capability to go to cold shutdown. The major impact results from the requirement for safety-related atmospheric dump valves.

** Beaver Valley Power Station - Unit 2 falls within the category of a Class 2 plant as defined by Section H, “Implementation,” of Branch Technical Position RSB 5-1, Revision 2.