AP1000 DOCUMENT COVER SHEET

TDC: ______ Permanent File: ______ S ______

RFS#: ______ RFS ITEM #: ______

AP1000 DOCUMENT NO.	REVISION NO.		ASSIGNED TO
APP-GW-GL-700	15	Page 1 of 1	W – W. E. Cummins

ALTERNATE DOCUMENT NUMBER: WORK BREAKDOWN #:

ORIGINATING ORGANIZATION: Westinghouse Electric Company LLC

TITLE: **AP1000 Design Control Document**

ATTACHMENTS:	DCP #/REV. INCORPORATED IN THIS DOCUMENT REVISION: See "Tier 1 Revision 15 Change Roadmap" and "Tier 2 Revision 15 Change Roadmap."
CALCULATION/ANALYSIS REFERENCE: N/A	

ELECTRONIC FILENAME	ELECTRONIC FILE FORMAT	ELECTRONIC FILE DESCRIPTION

ORIGINATOR D. A. Lindgren	SIGNATURE/DATE D. A. Lindgren 11/11/2005		
REVIEWERS	SIGNATURE/DATE		
VERIFIER R. P. Vijuk	SIGNATURE/DATE R. P. Vijuk 11/11/05	VERIFICATION METHOD	
AP1000 RESPONSIBLE MANAGER W. E. Cummins	SIGNATURE* W E Cummins	APPROVAL DATE 11/11/05	

*Approval of the responsible manager signifies that document is complete, all required reviews are complete, electronic file is attached and document is released for use.

Design Control Document, Revision 15

For information address: Westinghouse Electric Company LLC
Nuclear Plant Projects
P. O. Box 355
Pittsburgh, PA 15230

TABLE OF CONTENTS

LIST OF TABLES

DESIGN CONTROL DOCUMENT INTRODUCTION

1.0 SCOPE AND PURPOSE OF THE DESIGN CONTROL DOCUMENT

This Design Control Document (DCD) is a repository of information comprising the AP1000TM(*) Standard Plant Design. The design control document also provides that design-related information to be incorporated by reference into Appendix D to 10 CFR Part 52 (the AP1000 design certification rule).

Applicants for a combined license pursuant to 10 CFR 52 must ensure that Appendix D to 10 CFR Part 52 and the associated Statements of Consideration are used when making licensing decisions relevant to the AP1000 Standard Plant Design.

Further sections of this introduction summarize the contents and use of the design control document. The design control document contains this introduction, the Tier 1 Information and the Tier 2 Information for the AP1000 Standard Plant Design.

Detailed information on the application and use of the AP1000 design control document may be found in Appendix D to 10 CFR Part 52.

If there is a conflict between this introduction and the AP1000 design certification rule, the AP1000 design certification rule controls.

1.1 Tier 1 Information

Tier 1 means the portion of the design-related information contained in the AP1000 design control document that is approved and certified by the NRC. Tier 1 information includes:

- Definitions and general provisions;
- Design descriptions;
- Inspections, tests, analyses, and acceptance criteria (ITAAC);
- Significant site parameters; and
- Significant interface requirements between the AP1000 Standard Plant Design and systems that are wholly or partially outside the scope of the AP1000 Standard Plant Design

The Tier 1 Information includes a table of contents, a figure legend and an abbreviation list.

---

* AP1000 is a trademark of Westinghouse Electric Company LLC

1.2 Tier 2 Information

Tier 2 means the portion of the design-related information contained in the AP1000 Design Control Document that is approved but not certified by the NRC. Tier 2 information includes:

- Information required by 10 CFR 52.47, with the exception of generic technical specifications and conceptual design information;
- Information required for a final safety analysis report under 10 CFR 50.34;
- Supporting information on the inspections, tests, and analyses that will be performed to demonstrate that the acceptance criteria in the ITAAC have been met; and
- Combined license (COL) information items which identify certain matters that shall be addressed in the site-specific portion of the final safety analysis report (FSAR) by an applicant who references the AP1000 design certification rule

Each volume of the Tier 2 Information includes a master table of contents and each chapter contains a chapter specific table of contents.

1.3 Relationship of the Tier 1 Information to the Tier 2 Information

The design descriptions, interface requirements, and site parameters in Tier 1 are derived from Tier 2 information.

Compliance with Tier 2 is required, but generic changes to and plant-specific departures from Tier 2 are governed by the AP1000 design certification rule. Compliance with Tier 2 provides a sufficient, but not the only acceptable, method for complying with Tier 1. Compliance methods differing from Tier 2 must satisfy the change process in Section VIII of the AP1000 design certification rule.

1.4 Uses of the Design Control Document

An applicant for a license that wishes to reference the AP1000 design certification rule shall, in addition to complying with the requirements of 10 CFR 52.77, 52.78, and 52.79, comply with the following requirements:

- Incorporate by reference, as part of its application, the AP1000 design certification rule;
- Include, as part of its application:
  - A plant-specific design control document containing the same information and utilizing the same organization and numbering as the generic design control document for the AP1000 Standard Plant Design, as modified and supplemented by the applicant's exemptions and departures;
  - The reports on departures from and updates to the plant-specific design control document required by Section X of the AP1000 design certification rule;

- Plant-specific technical specifications, consisting of the generic and site-specific technical specifications, that are required by 10 CFR 50.36 and 50.36a;
- Information demonstrating compliance with the site parameters and interface requirements;
- Information that addresses the COL information items; and
- Information required by 10 CFR 52.47(a) that is not within the scope of the AP1000 design certification rule.
- Physically include, in the plant-specific design control document, the proprietary information referenced in the AP1000 design control document.

The Commission reserves the right to determine in what manner the AP1000 design certification rule may be referenced by an applicant for a construction permit or operating license under 10 CFR Part 50.

2.0 EFFECT OF THE TIER 1 INFORMATION

The following provisions describe the scope and effect of the Tier 1 Information.

2.1 Compliance with Tier 1 Information

All of the information in the Tier 1 Information is approved by the NRC and is applicable to a license application for a license that references the AP1000 design certification rule, and is among the "matters resolved" under 10 CFR52.63 (a)(4). The provisions and methods specified in the Tier 1 Information shall be complied with unless a plant specific exemption is granted by the NRC or a change is made to the Tier 1 Information in accordance with the change process specified in Section VIII of the AP1000 design certification rule.

2.2 Design Descriptions

The Design Descriptions pertain only to the design of structures, systems and components of an AP1000 Standard Plant Design and not to their operation, maintenance and administration. In the event of an inconsistency between the Design Descriptions and the Tier 2 Information, the Design Descriptions shall govern.

2.3 Inspections, Tests, Analyses and Acceptance Criteria

An applicant or licensee who references the AP1000 design certification rule shall perform and demonstrate conformance with the ITAAC before fuel load. With respect to activities subject to an ITAAC, an applicant for a license may proceed at its own risk with design and procurement activities, and a licensee may proceed at its own risk with design, procurement, construction, and preoperational activities, even though the NRC may not have found that any particular ITAAC has been satisfied.

In the event that an activity is subject to an ITAAC, and the applicant or licensee who references the AP1000 design certification rule has not demonstrated that the ITAAC has been satisfied, the applicant or licensee may either take corrective actions to successfully complete that ITAAC, request an exemption from the ITAAC in accordance with Section VIII of the AP1000 design certification rule and 10 CFR 52.97(b), or petition for rulemaking to amend the AP1000 design certification rule by changing the requirements of the ITAAC, under 10 CFR 2.802 and 52.97(b).

In accordance with 10 CFR 52.99 and 52.103(g), the Commission shall find that the acceptance criteria in the ITAAC for the license are met before fuel load.

After the Commission has made the finding required by 10 CFR 52.103(g), the ITAAC do not, by virtue of their inclusion within the design control document, constitute regulatory requirements either for licensees or for renewal of the license; except for specific ITAAC, which are the subject of a Section 103(a) hearing, their expiration will occur upon final Commission action in such proceeding. However, subsequent modifications must comply with the Tier 1 and Tier 2 design descriptions in the plant-specific design control document unless the licensee has complied with the applicable requirements of 10 CFR 52.97 and Section VIII of the AP1000 design certification rule.

2.4 Tier 1 Site Parameters

Site parameters are specified in the Tier 1 Information to establish the bounding parameters to be used in the selection of a suitable site for the facility referencing the AP1000 certified design. Since the Tier 1 Information Site Parameters were used in the bounding evaluations of the certified design, they define the requirements for the design that must be met to ensure that a facility built on the site remains in conformance with the design certification. In the event that an inconsistency between the Tier 1 Information Site Parameters and the Tier 2 Information, the Tier 1 Information Site Parameters shall govern.

2.5 Tier 1 Interface Requirements

The Tier 1 Interface Requirements describe the significant design provisions for interfaces between the AP1000 Standard Plant Design and structures, systems and components that are wholly or partially outside the scope of the AP1000 Standard Plant Design. Tier 1 Interface Requirements also define the significant attributes and performance characteristics that the out-of-scope portion of the plant must have in order to support the in-scope portion of the design. The FSAR shall contain provisions which implement the Interface Requirements in accordance with 10 CFR 52.79(b). Any plant-specific application for a COL shall contain additional ITAAC corresponding to these implementing provisions. In the event of an inconsistency between the Tier 1 Interface Requirements and the Tier 2 Information, the Tier 1 Interface Requirements shall govern.

3.0 EFFECT OF THE TIER 2 INFORMATION

The following provisions describe the scope and effect of the Tier 2 Information.

3.1 Compliance with the Tier 2 Information

All of the information in the Tier 2 Information is approved by the NRC and, with the exceptions noted in Sections 3.2 and 3.4 below, is applicable to a license that references the AP1000 design certification rule and is among the "matters resolved" under 10 CFR 52.63(a)(4). Compliance with the Tier 2 Information is a sufficient, but not necessarily the only, method of complying with the Tier 1 Information. The provisions and methods specified in the Tier 2 Information shall be followed unless a change is made in accordance with Section VIII of the AP1000 design certification rule.

3.2 COL Information Items

Combined license (COL) information items, which identify certain matters that shall be addressed in the site-specific portion of the final safety analysis report (FSAR) by an applicant who references the AP1000 design certification rule. These items constitute information requirements but are not the only acceptable set of information in the FSAR. An applicant may depart from or omit these items, provided that the departure or omission is identified and justified in the FSAR. After issuance of a construction permit or COL, these items are not requirements for the licensee unless such items are restated in the FSAR.

A summary of the AP1000 COL Information Items is provided in Table 1.8-2 of the Tier 2 Information.

3.3 Tier 2 Interface Requirements

The Tier 2 Interface Requirements describe the design provisions for interfaces between the AP1000 Standard Plant Design and structures, systems and components that are wholly or partially outside the scope of the AP1000 Standard Plant Design. Tier 2 Interface Requirements, summarized in Table 1.8-1 of the Tier 2 Information, also define the attributes and performance characteristics that the out-of-scope portion of the plant must have in order to support the in-scope portion of the design. The FSAR shall contain provisions which implement the Tier 2 Interface Requirements in accordance with 10 CFR 52.79(b). In the event of an inconsistency between the Tier 1 Interface Requirements and the Tier 2 Interface Requirements, the Tier 1 Interface Requirements shall govern.

3.4 Conceptual Designs

Conceptual designs for those portions of the plant that are outside the scope of the AP1000 Standard Plant Design are described and designated as out-of-scope in various places in the Tier 2 Information. As provided by 10 CFR 52.47(a)(1)(ix), these conceptual designs are not a part of the design certification for the AP1000 Standard Plant Design and do not impose requirements applicable to a COL, nor an application for a COL, that references the AP1000 design certification rule. Those portions of the AP1000 Standard Plant Design for which conceptual designs are

included in the Tier 2 Information are identified by double brackets and listed in Section 1.8 of the Tier 2 Information.

3.5 Plant-Specific Changes to Designated Information in the Tier 2 Information

*Tier 2** means the portion of the Tier 2 information, designated as such in the AP1000 design control document, which is subject to the change process in Section VIII of the AP1000 design certification rule. This designation expires for some Tier 2* information under Section VIII of the AP1000 design certification rule.

An applicant who references the AP1000 design certification rule may not depart from Tier 2* information, which is designated with italicized text or brackets and an asterisk in the AP1000 design control document, without NRC approval. The departure will not be considered a resolved issue, within the meaning of Section VI of the AP1000 design certification rule and 10 CFR 52.63(a)(4).

The AP1000 Tier 2* information, summarized in Table 1-1 of this introduction, is designated with italicized text in the Tier 2 Information. Certain figures that are indicated to be Tier 2* may contain information beyond that that is considered to be Tier 2*. A review of the text referencing the figure may be necessary to determine what information on the figure is considered to be Tier 2*. The AP1000 Tier 2* information for which the Tier 2* designation expires when the COL holder first achieves 100% power operation is indicated in Table 1-1 of this introduction.

3.6 Treatment of Probabilistic Risk Assessment Information

A design-specific Probabilistic Risk Assessment (PRA) for the AP1000 Standard Plant Design was submitted as a part of the application for design certification as required by 10 CFR 52.47. One purpose of the PRA was to develop insights for the design and its features. Significant insights that resulted from the PRA are identified in Section 19.59 of the Tier 2 Information. However, the detailed methodology and quantitive portions of the design-specific PRA are not included in the Design Control Document because it is anticipated that this material will be subject to modifications and refinements as the detailed design is completed and the as-built plant parameters and new methodology become available.

Table 1-1
Index of AP1000 Tier 2 Information Requiring NRC Approval for Change

Item	Expiration at First Full Power	Tier 2 Reference
Dimensions for Nuclear Island Structures	Yes	3.7.1.4 Table 3.7.1-2 Figure 3.7.1-14
Nuclear Island Key Structural Dimensions	Yes	3.7.2 Figure 3.7.2-12
Polar Crane Parked Orientation	Yes	3.7.2.3.2
Containment Vessel Design Characteristics and Spacing Between Each Pair of Ring Supports	Yes	3.8.2.1.1
2001 Edition of ASME Code, Section III, including 2002 Addenda	Yes	3.8.2.2 3.8.2.5 5.2.1.1
ASME Code Case N-284-1	Yes	3.8.2.2 3.8.2.5
Use of ACI-349-01	Yes	3.8.3.2 3.8.4.2 3.8.4.4.1 3.8.4.5 3.8.4.5.1 3.8.5.5 Table 3.8.4-2
Use of AISC N690-1994	Yes	3.8.3.2 3.8.4.2 3.8.4.4.1 3.8.4.5 3.8.4.5.2 Table 3.8.4-1
Use of AISI	Yes	3.8.4.4.1 3.8.4.5
Design Summary of Critical Sections Inside Containment	Yes	3.8.3.5.8.1 3.8.3.5.8.2 3.8.3.5.8.3 Table 3.8.3-3 Table 3.8.3-4 Table 3.8.3-5 Table 3.8.3-6 Table 3.8.4-1 Figure 3.8.3-1 Figure 3.8.3-2

Table 1-1 (Cont.)
Index of AP1000 Tier 2 Information Requiring NRC Approval for Change

Item	Expiration at First Full Power	Tier 2 Reference
Design Summary of Critical Sections Inside Containment (Cont.)		Figure 3.8.3-8 Figure 3.8.3-14 Figure 3.8.3-15 Figure 3.8.3-17 Figure 3.8.3-18
Design Summary of Critical Sections Outside Containment	Yes	3.8.4.5.4 Figure 3.8.4-2 Figure 3.8.4-4 Figure 3.8.5-3 App 3H.1 App 3H.2 App 3H.3 App 3H.3.1 App 3H.3.2 App 3H.3.3 App 3H.4 App 3H.4.1 App 3H.5 App 3H.5.1 App 3H.5.1.1 App 3H.5.1.2 App 3H.5.1.3 App 3H.5.1.4 App 3H.5.1.5 App 3H.5.2 App 3H5.2.1 App 3H.5.2.2 App 3H.5.3 App 3H.5.3.1 App 3H.5.4 App 3H.5.5 App 3H.5.5.1 App 3H.5.6 App 3H.5.6.1 App 3H.5.6.2 App 3H.5.6.3 Table 3H.5-1 Table 3H.5-2 Table 3H.5-3 Table 3H.5-4 Table 3H.5-5 Table 3H.5-6 Table 3H.5-7

Table 1-1 (Cont.)
Index of AP1000 Tier 2 Information Requiring NRC Approval for Change

Item	Expiration at First Full Power	Tier 2 Reference
Design Summary of Critical Sections Outside Containment (Cont.)		Table 3H.5-8 Table 3H.5-9 Table 3H.5-10 Table 3H.5-11 Table 3H.5-12 Table 3H.5-13 Figure 3H.2-1 Figure 3H.5-1 Figure 3H.5-2 Figure 3H.5-3 Figure 3H.5-4 Figure 3H.5-5 Figure 3H.5-6 Figure 3H.5-7 Figure 3H.5-8 Figure 3H.5-9 Figure 3H.5-10 Figure 3H.5-11 Figure 3H.5-12
Design Summary of Critical Sections for Nuclear Island Basemat	Yes	3.8.5.4.3 Table 3.8.5-3
Seismic Qualification Standards	Yes	3.10.1.1
Methods and Procedures for Qualifying Electrical Equipment, Instrumentation, and Mechanical Components	Yes	3.10.2
Experienced-Based Qualification	Yes	3.10.6
Maximum Fuel Rod Average Burnup	No	4.3.1.1.1
Fuel Principal Design Requirements	No	4.1.1
WCAP-12488-P-A, "Fuel Criteria Evaluation Process"	No	4.1 4.1.3 4.2 4.2.1 4.2.1.1.2 4.2.1.1.3 4.2.1.5 4.2.1.6 4.2.3 4.2.6 4.3.1 4.3.5

Table 1-1 (Cont.)
Index of AP1000 Tier 2 Information Requiring NRC Approval for Change

Item	Expiration at First Full Power	Tier 2 Reference
Reactor Core Description (First Cycle)	Yes	Table 4.3-1
Nuclear Design Parameters (First Cycle)	Yes	Table 4.3-2
Reactivity Requirements for Rod Cluster Control Assemblies	Yes	Table 4.3-3
MOV Design and Qualification	Yes	5.4.8.1.2
Other Power-Operated Valves Design and Qualification	Yes	5.4.8.1.3
Motor Operated Valves	Yes	5.4.8.5.2
Power Operated Valves	Yes	5.4.8.5.3
N-284-1 Metal Containment Shell Buckling Design Methods, Section III, Division I Class MC	Yes	Table 5.2-3
WCAP-13383, "AP600 Instrumentation and Control Hardware & Software Design, Verification & Validation Process Report," Rev 1.	Yes	Chapter 7 Table 1.6-1
WCAP-14605, "Westinghouse Setpoint Methodology for Protection Systems, AP600," Rev 0	Yes	Chapter 7 Table 1.6-1
CENPD-396-P, Rev. 01, "Common Qualified Platform"	Yes	Chapter 7 Table 1.6-1
CE-CES-195, "Software Program Manual for Common Q Systems," Rev 01	Yes	Chapter 7 Table 1.6-1
WCAP-15927, "Design Process for AP1000 Common Q Safety Systems," Rev 0	Yes	Chapter 7 Table 1.6-1
Verification and Validation	Yes	7.1.2.14
Hard-wired DAS manual actuation	No	7.7.1.11
Nuclear Island Fire Areas	No	Figure 9A-1
Turbine Building Fire Areas	No	Figure 9A-2
Annex I & II Building Fire Areas	No	Figure 9A-3
Radwaste Building Fire Areas	No	Figure 9A-4
Diesel Generator Building Fire Areas	No	Figure 9A-5
Natural Circulation Test	First Plant Only	14.2.5
Description of "First Three Plant Tests"	Third Plant	14.2.5
Verification of proper operation of core makeup tanks in recirculation mode	Third Plant	14.2.9.1.3

Table 1-1 (Cont.)
Index of AP1000 Tier 2 Information Requiring NRC Approval for Change

Item	Expiration at First Full Power	Tier 2 Reference
Verification of automatic depressurization during hot functional testing	Third Plant	14.2.9.1.3
Verification of proper operation of core makeup tanks to transition to draindown mode	Third Plant	14.2.9.1.3
Passive Residual Heat Removal Heat Exchanger Natural Circulation Test	First Plant Only	14.2.10.3.7
First-Plant-Only and Three-Plant-Only Tests	As Discussed	14.4.6
10 CFR 50.46 Criteria for NOTRUMP Homogeneous Sensitivity Model	No	15.6.5.4B.2.2
10 CFR 50.46 Criteria for Critical Heat Flux Assessment	No	15.6.5.4B.2.3
WCAP-14396, "Man-in-the-Loop Test Plan Description," Rev 3	No	Table 1.6-1
WCAP-15860, "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan," Rev 2	No	Table 1.6-1
WCAP-14651, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," Rev 2	No	Table 1.6-1
WCAP-14695, "Description of the Westinghouse Operator Decision Making Model and Function Based Task Analysis Methodology," Rev 0	No	Table 1.6-1
WCAP-15847, "AP1000 Quality Assurance Procedures Supporting NRC review of AP1000 SSAR Sections 18.2 and 18.8," Rev 1	No	Table 1.6-1
Basis for Human Factors Engineering Program	No	18.1
NUREG-0711, "Human Factors Engineering Program Review Model," July 1994 WCAP-14651, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," Rev 2 WCAP-15860, "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan," Rev 2	No	18.1.1
NUREG-0711, "Human Factors Engineering Program Review Model," July 1994	No	18.2.1.2
Applicable Facilities	No	18.2.1.3
Applicable Human Systems Interfaces	No	18.2.1.4
Applicable Plant Personnel	No	18.2.1.5

Table 1-1 (Cont.)
Index of AP1000 Tier 2 Information Requiring NRC Approval for Change

Item	Expiration at First Full Power	Tier 2 Reference
Technical Basis NUREG-0711, "Human Factors Engineering Program Review Model," July 1994	No	18.2.1.6
Responsibility of Human System Interface Design Team	No	18.2.2.1
Composition of HFE Design Team	No	18.2.2.3
Action Item Tracking	No	18.2.3.1
Subcontractor Efforts WCAP-15847, "AP1000 Quality Assurance Procedures Supporting NRC review of AP1000 SSAR Sections 18.2 and 18.8," Rev 1	No	18.2.3.5
General Process and Procedures for Design Review of HFE Products	No	18.2.4
HFE Technical Program and Milestones NUREG-0711, "Human Factors Engineering Program Review Model," July 1994 NUREG-0711, "Human Factors Engineering Program Review Model," Rev 1	No	18.2.5
NUREG-0711, "Human Factors Engineering Program Review Model," July 1994 WCAP-15847, "AP1000 Quality Assurance Procedures Supporting NRC review of AP1000 SSAR Sections 18.2 and 18.8," Rev 1 NUREG-0711, "Human Factors Engineering Program Review Model," Rev 1	No	18.2.7
Human System Interface Design Team Process	No	Figure 18.2-1
AP600 Task Analysis Implementation Plan NUREG-0711, "Human Factors Engineering Program Review Model," July 1994	No	18.5
Task Analysis Scope WCAP-14651, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," Rev 2	No	18.5.1
Task Analysis Implementation Plan	No	18.5.2

Table 1-1 (Cont.)
Index of AP1000 Tier 2 Information Requiring NRC Approval for Change

Item	Expiration at First Full Power	Tier 2 Reference
Function-Based Task Analysis WCAP-14695, "Description of the Westinghouse Operator Decision Making Model and Function Based Task Analysis Methodology," Rev 0	No	18.5.2.1
NUREG-0711, "Human Factors Engineering Program Review Model," July 1994 WCAP-14695, "Description of the Westinghouse Operator Decision Making Model and Function Based Task Analysis Methodology," Rev 0 WCAP-14651, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," Rev 2	No	18.5.5
Integration of Human Reliability Analysis with HFE WCAP-14651, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," Rev 2	No	18.7
WCAP-14651, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," Rev 2	No	18.7.2
Human System Interface Design WCAP-14695, "Description of the Westinghouse Operator Decision Making Model and Function Based Task Analysis Methodology," Rev 0 WCAP-15860, "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan," Rev 2	No	18.8
Design Guidelines WCAP-15860, "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan," Rev 2	No	18.8.1.2
Man-in-the-Loop Test Plan to Obtain Feedback from Prototype Design Products WCAP-14396, "Man-in-the-Loop Test Plan Description," Rev 3	No	18.8.1.4
HSI Design Provides Necessary Alarms, Displays, and Controls WCAP-15860, "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan," Rev 2	No	18.8.1.7

Table 1-1 (Cont.)
Index of AP1000 Tier 2 Information Requiring NRC Approval for Change

Item	Expiration at First Full Power	Tier 2 Reference
Operator Decision-Making Model Used by Task Analysis Activities WCAP-14695, "Description of the Westinghouse Operator Decision Making Model and Function Based Task Analysis Methodology," Rev 0	No	18.8.1.8
Critical Human Actions and Risk-Important Tasks WCAP-14651, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," Rev 2	No	18.8.1.9
Safety Parameter Display System 10 CFR 50.34(f)(2)(iv) NUREG-0737, Supplement 1, "Requirements for Emergency Response Capability"	No	18.8.2
Implementation Plan for Integrating Human Reliability Analysis with HFE WCAP-14651, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," Rev 2	No	18.8.2.1
Display of Safety Parameters WCAP-14695, "Description of the Westinghouse Operator Decision Making Model and Function Based Task Analysis Methodology," Rev 0	No	18.8.2.2
Safety Parameter Display System HFE NUREG-0711, "Human Factors Engineering Program Review Model," July 1994	No	18.8.2.5
Minimum Information, Safety Parameter Display System Design NUREG-1342, "A Status Report Regarding Industry Implementation of Safety Parameter Display Systems"	No	18.8.2.6
Main Control Area Mission and Major Tasks Regulatory Guide 1.97	No	18.8.3.2
Remote Shutdown Workstation Mission and Major Tasks	No	18.8.3.4
Technical Support Center Mission and Major Tasks NUREG-0737, Supplement 1, "Requirements for Emergency Response Capability"	No	18.8.3.5

Table 1-1 (Cont.)
Index of AP1000 Tier 2 Information Requiring NRC Approval for Change

Item	Expiration at First Full Power	Tier 2 Reference
WCAP-14651, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," Rev 2 WCAP-15860, "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan," Rev 2 WCAP-14695, "Description of the Westinghouse Operator Decision Making Model and Function Based Task Analysis Methodology," Rev 0 10 CFR 50.34(f)(2)(iv) NUREG-0737, Supplement 1, "Requirements for Emergency Response Capability" NUREG-0711, "Human Factors Engineering Program Review Model," July 1994 NUREG-1342, "A Status Report Regarding Industry Implementation of Safety Parameter Display Systems" WCAP-14396, "Man-in-the-Loop Test Plan Description," Rev 3	No	18.8.6
Human Performance Issues to be Addressed by HSI Design	No	Table 18.8-1
Human Factors Engineering Verification and Validation WCAP-15860, "Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan," Rev 2	No	18.11.2
Inventory of Displays, Alarms, and Controls	No	18.12.1
Implementation Process for Identification of Critical PRA Operator Actions WCAP-14651, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," Rev 2	No	18.12.2
Remote Shutdown Workstation Displays, Alarms, and Controls	No	18.12.3
WCAP-14651, "Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan," Rev 2	No	18.12.5
Piping Design Analysis Criteria (DAC)	Yes	See DCD Intro, Table 1-2

Table 1-2
Piping Design Acceptance Criteria

Commitment	Tier 2 Reference
ASME Code and Code Cases for AP1000 piping and pipe support design	Table 3.9-9, Table 3.9-10, 5.2.1.1, 5.2.1.2, Table 5.2-3
Analysis Methods; experimental stress analysis, independent support motion, inelastic analysis, non-seismic/seismic interaction, buried piping	3.7.3.9, 3.7.3.12, 3.7.3.13, 3.9.1.3, 3.9.3.1.5
Piping Modeling; piping benchmark program, decoupling criteria	3.6.2.1.1.1, 3.6.2.1.1.2, 3.6.2.1.1.3, 3.7.3.8.2.1, 3.9.1.2
Pipe stress analysis criteria; loading and load combinations, damping values, combination of modal responses, high frequency modes, thermal oscillations in piping connected to the reactor coolant system, thermal stratification, safety-related valve design, installation and testing, functional capability, combination of inertial and seismic motion effects, welded attachments, modal damping for composite structures, minimum temperature for thermal analysis	3.6.2.2, 3.6.3.3, 3.7.2.14, 3.7.3.2, 3.7.3.7, 3.7.3.8.2.1, 3.7.3.9, Table 3.7.1-1, 3.9.3.1.2, 3.9.3.1.5, 3.9.3.3, Table 3.9-5, Table 3.9-6, Table 3.9-7, Table 3.9-8, Table 3.9-9, Table 3.9-10, Table 3.9-11
Pipe support criteria; applicable codes, jurisdictional boundaries, pipe support baseplate and anchor bolt design, use of energy absorbers and limit stops, pipe support stiffnesses, seismic self-weight excitation, design of supplementary steel, considerations of friction forces, pipe support gaps and clearances, instrument line support criteria	3.9.1.2, 3.9.3.4, 3.9.3.5
Equivalent Static Load Method of Analysis	3.7.3.5, 3.7.3.5.1, 3.7.3.5.2
Three Components of Earthquake Motion	3.7.3.6
Left-Out-Force Method Used in PIPESTRESS Program	3.7.3.7.1.1
SRP 3.7.2 Method for High-Frequency Modes	3.7.3.7.1.2
Combination of Low-Frequency Modes	3.7.3.7.2
Modeling Methods and Analytical Procedures for Piping Systems	3.7.3.8, 3.7.3.8.1, 3.7.3.8.2.2, 3.7.3.8.3, 3.7.3.8.4
Seismic Anchor Motions	3.7.3.9
Methods Used to Account for Torsional Effects of Eccentric Masses	3.7.3.11
Design Methods of Piping to Prevent Adverse Spatial Interactions	3.7.3.13.4, 3.7.3.13.4.1, 3.7.3.13.4.2, 3.7.3.13.4.3
Analysis Procedure for Damping	3.7.3.15
Time History Analysis of Piping Systems	3.7.3.17
Design Transients Use of NRC Bulletins 88-08 and 88-11	3.9.1.1

Table 1-2 (Cont.)
Piping Design Acceptance Criteria

Commitment	Tier 2 Reference
Loads for Class 1 Components and Core/Component Supports	3.9.3.1.2
Use of Square-Root-Sum-of-the-Squares Method for SSE plus Pipe Rupture	3.9.3.1.3
Analysis of Reactor Coolant Loop Piping	3.9.3.1.4
ASME Classes 1, 2, and 3 Piping Use of ASME Code, Section III	3.9.3.1.5
Design of Spring-Loaded Safety Valves	3.9.3.3.1
Design and Analysis Requirement for Open and Closed Discharge Systems	3.9.3.3.3
Component and Piping Supports for Dynamic Loading	3.9.3.4
Class 2 and 3 Component Supports Use of ASME Section III	3.9.3.4.2
Piping System Seismic Stress Analysis	3.9.3.4.3
Design Report for ASME Class 1, 2, and 3 Piping	3.9.8.2
Integrity of Nonsafety-Related CVS Piping Inside Containment Compliance with 10 CFR 50.55a and ASME B31.1 Code	5.2.1.1

TIER 1 MASTER TABLE OF CONTENTS

Section **Page**

TIER 1 MASTER TABLE OF CONTENTS (Cont.)

TIER 1 MASTER TABLE OF CONTENTS (Cont.)

* Underlined sections - title only, no entry for Design Certification.

TIER 1 LIST OF FIGURES

TIER 1 LIST OF FIGURES (Cont.)

[This page intentionally blank]

AP1000
TIER 1 LIST OF EFFECTIVE PAGES

Page	Revision
i	10
ii	10
Intro-1	11
Intro-2	11
Intro-3	11
Intro-4	11
Intro-5	11
Intro-6	11
Intro-7	11
Intro-8	11
Intro-9	11
Intro-10	11
Intro-11	11
Intro-12	11
Intro-13	11
Intro-14	11
Intro-15	11
Intro-16	11
Intro-17	11
i	15
ii	15
iii	15
iv	15
v	15
vi	15
vii	15
viii	15
ix	15
x	15
xi	15
xii	15
xiii	15
xiv	15
xv	15
xvi	15
xvii	15
xviii	15
xix	15
xx	15
xxi	15
xxii	15
xxiii	15
xxiv	15
xxv	15
xxvi	15
1.1-1	15
1.1-2	15
1.2-1	15
1.2-2	15
1.3-1	0
1.3-2	0
1.3-3	0
1.3-4	0
1.4-1	15
1.4-2	15
1.4-3	15
1.4-4	15
1.4-5	15
2.1.1-1	15
2.1.1-2	15
2.1.1-3	15
2.1.1-4	15
2.1.2-1	15
2.1.2-2	15
2.1.2-3	15
2.1.2-4	15
2.1.2-5	15
2.1.2-6	15
2.1.2-7	15
2.1.2-8	15
2.1.2-9	15
2.1.2-10	15
2.1.2-11	15
2.1.2-12	15
2.1.2-13	15
2.1.2-14	15
2.1.2-15	15
2.1.2-16	15
2.1.2-17	15
2.1.2-18	15
2.1.2-19	15
2.1.2-20	15
2.1.2-21	15
2.1.2-22	15
2.1.2-23	15
2.1.2-24	15
2.1.2-25	15
2.1.2-26	15
2.1.2-27	15
2.1.2-28	15
2.1.2-29	15
2.1.2-30	15
2.1.2-31	15
2.1.2-32	15
2.1.3-1	15
2.1.3-2	15
2.1.3-3	15
2.1.3-4	15
2.1.3-5	15
2.1.3-6	15
2.1.3-7	15
2.1.3-8	15
2.1.3-9	15
2.1.3-10	15
2.1.3-11	15
2.1.3-12	15
2.1.3-13	15
2.1.3-14	15
2.1.3-15	15
2.2.1-1	15
2.2.1-2	15
2.2.1-3	15
2.2.1-4	15
2.2.1-5	15
2.2.1-6	15
2.2.1-7	15
2.2.1-8	15
2.2.1-9	15
2.2.1-10	15
2.2.1-11	15
2.2.1-12	15
2.2.1-13	15
2.2.1-14	15
2.2.1-15	15
2.2.2-1	15
2.2.2-2	15
2.2.2-3	15
2.2.2-4	15
2.2.2-5	15
2.2.2-6	15
2.2.2-7	15
2.2.2-8	15
2.2.2-9	15
2.2.2-10	15
2.2.2-11	15
2.2.2-12	15
2.2.2-13	15
2.2.2-14	15
2.2.2-15	15
2.2.2-16	15
2.2.3-1	15
2.2.3-2	15
2.2.3-3	15
2.2.3-4	15
2.2.3-5	15
2.2.3-6	15
2.2.3-7	15
2.2.3-8	15
2.2.3-9	15
2.2.3-10	15
2.2.3-11	15
2.2.3-12	15
2.2.3-13	15
2.2.3-14	15
2.2.3-15	15
2.2.3-16	15
2.2.3-17	15
2.2.3-18	15
2.2.3-19	15
2.2.3-20	15
2.2.3-21	15

AP1000
TIER 1 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision
2.2.3-22	15
2.2.3-23	15
2.2.3-24	15
2.2.3-25	15
2.2.3-26	15
2.2.3-27	15
2.2.3-28	15
2.2.3-29	15
2.2.4-1	15
2.2.4-2	15
2.2.4-3	15
2.2.4-4	15
2.2.4-5	15
2.2.4-6	15
2.2.4-7	15
2.2.4-8	15
2.2.4-9	15
2.2.4-10	15
2.2.4-11	15
2.2.4-12	15
2.2.4-13	15
2.2.4-14	15
2.2.4-15	15
2.2.4-16	15
2.2.4-17	15
2.2.4-18	15
2.2.4-19	15
2.2.4-20	15
2.2.4-21	15
2.2.4-22	15
2.2.4-23	15
2.2.4-24	15
2.2.4-25	15
2.2.5-1	15
2.2.5-2	15
2.2.5-3	15
2.2.5-4	15
2.2.5-5	15
2.2.5-6	15
2.2.5-7	15
2.2.5-8	15
2.2.5-9	15
2.2.5-10	15
2.2.5-11	15
2.2.5-12	15
2.2.5-13	15
2.2.5-14	15
2.2.5-15	15
2.3.1-1	15
2.3.1-2	15
2.3.1-3	15
2.3.1-4	15
2.3.1-5	15
2.3.2-1	15
2.3.2-2	15
2.3.2-3	15
2.3.2-4	15
2.3.2-5	15
2.3.2-6	15
2.3.2-7	15
2.3.2-8	15
2.3.2-9	15
2.3.2-10	15
2.3.2-11	15
2.3.2-12	15
2.3.2-13	15
2.3.2-14	15
2.3.2-15	15
2.3.3-1	15
2.3.3-2	15
2.3.3-3	15
2.3.3-4	15
2.3.3-5	15
2.3.4-1	15
2.3.4-2	15
2.3.4-3	15
2.3.4-4	15
2.3.4-5	15
2.3.4-6	15
2.3.4-7	15
2.3.4-8	15
2.3.5-1	5
2.3.5-2	5
2.3.5-3	5
2.3.5-4	5
2.3.6-1	15
2.3.6-2	15
2.3.6-3	15
2.3.6-4	15
2.3.6-5	15
2.3.6-6	15
2.3.6-7	15
2.3.6-8	15
2.3.6-9	15
2.3.6-10	15
2.3.6-11	15
2.3.6-12	15
2.3.6-13	15
2.3.6-14	15
2.3.6-15	15
2.3.6-16	15
2.3.6-17	15
2.3.7-1	15
2.3.7-2	15
2.3.7-3	15
2.3.7-4	15
2.3.7-5	15
2.3.7-6	15
2.3.7-7	15
2.3.7-8	15
2.3.7-9	15
2.3.7-10	15
2.3.7-11	15
2.3.8-1	15
2.3.8-2	15
2.3.8-3	15
2.3.8-4	15
2.3.8-5	15
2.3.9-1	11
2.3.9-2	11
2.3.9-3	11
2.3.9-4	11
2.3.9-5	11
2.3.9-6	11
2.3.9-7	11
2.3.10-1	15
2.3.10-2	15
2.3.10-3	15
2.3.10-4	15
2.3.10-5	15
2.3.10-6	15
2.3.10-7	15
2.3.10-8	15
2.3.10-9	15
2.3.11-1	0
2.3.11-2	0
2.3.11-3	0
2.3.11-4	0
2.3.11-5	0
2.3.11-6	0
2.3.12-1	0
2.3.12-2	0
2.3.13-1	15
2.3.13-2	15
2.3.13-3	15
2.3.13-4	15
2.3.13-5	15
2.3.13-6	15
2.3.13-7	15
2.3.13-8	15
2.3.14-1	15
2.3.14-2	15
2.3.14-3	15

AP1000
TIER 1 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision
2.3.15-1	15
2.3.15-2	15
2.3.15-3	15
2.3.16-1	0
2.3.17-1	0
2.3.18-1	0
2.3.19-1	0
2.3.19-2	0
2.3.19-3	0
2.3.20-1	0
2.3.21-1	0
2.3.22-1	0
2.3.23-1	0
2.3.24-1	0
2.3.25-1	0
2.3.26-1	0
2.3.27-1	0
2.3.28-1	0
2.3.29-1	0
2.3.29-2	0
2.3.29-3	0
2.4.1-1	0
2.4.1-2	0
2.4.1-3	0
2.4.1-4	0
2.4.2-1	0
2.4.2-2	0
2.4.3-1	0
2.4.4-1	0
2.4.5-1	0
2.4.6-1	0
2.4.6-2	0
2.4.7-1	9
2.4.8-1	0
2.4.9-1	0
2.4.10-1	0
2.4.11-1	0
2.4.12-1	0
2.4.13-1	0
2.4.14-1	0
2.4.15-1	0
2.4.16-1	0
2.5.1-1	7
2.5.1-2	7
2.5.1-3	7
2.5.1-4	7
2.5.1-5	7
2.5.1-6	7
2.5.1-7	7
2.5.1-8	7
2.5.2-1	15
2.5.2-2	15
2.5.2-3	15
2.5.2-4	15
2.5.2-5	15
2.5.2-6	15
2.5.2-7	15
2.5.2-8	15
2.5.2-9	15
2.5.2-10	15
2.5.2-11	15
2.5.2-12	15
2.5.2-13	15
2.5.2-14	15
2.5.2-15	15
2.5.2-16	15
2.5.2-17	15
2.5.2-18	15
2.5.2-19	15
2.5.2-20	15
2.5.3-1	15
2.5.3-2	15
2.5.4-1	15
2.5.4-2	15
2.5.4-3	15
2.5.4-4	15
2.5.5-1	15
2.5.5-2	15
2.5.5-3	15
2.5.5-4	15
2.5.6-1	0
2.5.7-1	0
2.5.8-1	0
2.5.9-1	0
2.5.9-2	0
2.5.10-1	0
2.6.1-1	15
2.6.1-2	15
2.6.1-3	15
2.6.1-4	15
2.6.1-5	15
2.6.1-6	15
2.6.1-7	15
2.6.1-8	15
2.6.1-9	15
2.6.1-10	15
2.6.1-11	15
2.6.1-12	15
2.6.1-13	15
2.6.1-14	15
2.6.2-1	0
2.6.2-2	0
2.6.2-3	0
2.6.2-4	0
2.6.2-5	0
2.6.3-1	15
2.6.3-2	15
2.6.3-3	15
2.6.3-4	15
2.6.3-5	15
2.6.3-6	15
2.6.3-7	15
2.6.3-8	15
2.6.3-9	15
2.6.3-10	15
2.6.3-11	15
2.6.3-12	15
2.6.3-13	15
2.6.3-14	15
2.6.3-15	15
2.6.3-16	15
2.6.3-17	15
2.6.3-18	15
2.6.3-19	15
2.6.4-1	0
2.6.4-2	0
2.6.4-3	0

AP1000
TIER 1 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision
2.6.5-1	15
2.6.5-2	15
2.6.5-3	15
2.6.6-1	0
2.6.6-2	0
2.6.7-1	0
2.6.8-1	0
2.6.9-1	0
2.6.10-1	11
2.6.11-1	11
2.7.1-1	15
2.7.1-2	15
2.7.1-3	15
2.7.1-4	15
2.7.1-5	15
2.7.1-6	15
2.7.1-7	15
2.7.1-8	15
2.7.1-9	15
2.7.1-10	15
2.7.1-11	15
2.7.2-1	15
2.7.2-2	15
2.7.2-3	15
2.7.2-4	15
2.7.2-5	15
2.7.2-6	15
2.7.3-1	0
2.7.3-2	0
2.7.3-3	0
2.7.3-4	5
2.7.3-5	0
2.7.3-6	0
2.7.4-1	15
2.7.4-2	15
2.7.4-3	15
2.7.4-4	15
2.7.4-5	15
2.7.4-6	15
2.7.5-1	15
2.7.5-2	15
2.7.5-3	15
2.7.6-1	15
2.7.6-2	15
2.7.6-3	15
2.7.6-4	15
2.7.6-5	15
2.7.7-1	15
2.7.7-2	15
2.7.8-1	0
2.7.9-1	0
2.7.10-1	0
2.7.11-1	0
3.1-1	7
3.1-2	7
3.2-1	15
3.2-2	15
3.2-3	15
3.2-4	15
3.2-5	15
3.2-6	15
3.2-7	15
3.2-8	15
3.2-9	15
3.2-10	15
3.3-1	15
3.3-2	15
3.3-3	15
3.3-4	15
3.3-5	15
3.3-6	15
3.3-7	15
3.3-8	15
3.3-9	15
3.3-10	15
3.3-11	15
3.3-12	15
3.3-13	15
3.3-14	15
3.3-15	15
3.3-16	15
3.3-17	15
3.3-18	15
3.3-19	15
3.3-20	15
3.3-21	15
3.3-22	15
3.3-23	15
3.3-24	15
3.3-25	15
3.3-26	15
3.3-27	15
3.3-29	15
3.3-31	15
3.3-33	15
3.3-35	15
3.3-37	15
3.3-39	15
3.3-41	15
3.3-43	15
3.3-45	15
3.3-47	15
3.3-49	15
3.3-51	15
3.3-53	15
3.4-1	0
3.5-1	15
3.5-2	15
3.5-3	15
3.5-4	15
3.5-5	15
3.5-6	15
3.5-7	15
3.5-8	15
3.6-1	15
3.6-2	15
3.7-1	9
3.7-2	9
3.7-3	9
3.7-4	9
3.7-5	9
3.7-6	9
3.7-7	9
4.0-1	0
5.0-1	15
5.0-2	15
5.0-3	15
5.0-4	15
5.0-5	15
5.0-6	15

LIST OF TIER 1 REVISION 1 PAGES

Section	Page No.	Type of Change
VOLUME 1		
2.1.2	2.1.2-23 and 2.1.2-24	Technical
2.2.2	2.2.2-11	Technical
2.2.2	2.2.2-13	Technical
2.2.3	2.2.3-18 and 2.2.3-19	Technical
2.2.3	2.2.3-22	Technical
2.3.1	2.3.1-3	Technical
2.3.6	2.3.6-12 and 2.3.6-13	Technical
2.3.7	2.3.7-7	Technical
2.3.8	2.3.8-1	Technical
2.3.8	2.3.8-3	Technical
3.2	3.2-1	Technical
3.2	3.2-5	Technical
3.3	3.3-18	Technical
5.0	5.0-3	Technical

LIST OF TIER 1 REVISION 2 PAGES

Section	Page No.	Type of Change
VOLUME 1		
Tier 1 List of Effective Pages	1 through 4	Editorial
Master T of C	i through vi	Editorial
List of Tier 1 Revision 2 Pages	viii	Editorial
2.2.3	2.2.3-20	Technical

TIER 1 REVISION 3 CHANGE ROADMAP

Section	Page No.	Type of Change[1]
VOLUME 1		
AP1000 Document Cover Sheet		Editorial
Design Control Document, Title Page		Editorial
DCD Introduction, T of C	ii	Editorial
DCD Introduction	Intro-7	420.023
DCD Introduction	Intro-8	620.001 620.013 620.023 620.034 Editorial
DCD Introduction	Intro-9	210.032 620.002 620.003
DCD Introduction	Intro-10	210.032
Tier 1 List of Effective Pages	1 through 4	Editorial
Master T of C	i through vi	Editorial
Tier 1 Revision 3 Change Roadmap	ix and x	Editorial
2.1	2.1.2-23	440.040 (251.021) Editorial
2.1	2.1.2-25	Editorial
2.1	2.1.3-4	440.142
2.1	2.1.3-6	440.142
2.1	2.1.3-10	440.142
2.2	2.2.2-16	Technical
2.2	2.2.4-2	Editorial
2.2	2.2.4-19	440.145
2.3	2.3.6-5	Editorial
2.3	2.3.6-9	440.146
2.3	2.3.6-14	440.147
2.3	2.3.6-17	440.136
2.3	2.3.9-6	Editorial
2.3	2.3.13-8	Technical

TIER 1 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
2.5	2.5.1-2	420.038
2.5	2.5.1-3	440.148
2.5	2.5.1-7	420.038
2.5	2.5.2-2	420.040 (420.001)
2.5	2.5.2-2a and 2.5.2-2b	Editorial
2.5	2.5.2-15	420.040 (420.001)
2.5	2.5.4-4	Editorial
2.6	2.6.1-1	Editorial
2.7	2.7.4-5 and 2.7.4-6	Editorial
3.0	3.2-1	620.006
3.0	3.2-10	620.011
3.0	3.2-11	620.012
3.0	3.3-18	Editorial
3.0	3.3-20	Editorial
3.0	3.3-24	Editorial
3.0	3.3-25 through 3.3-43	Technical
5.0	5.0-3	240.002 (230.008) (241.001)

1. Changes incorporated as a result of Westinghouse responses to NRC Request for Additional Information (RAI) identified by RAI number. RAI number in parenthesis contains a reference to RAI response listed above.

TIER 1 REVISION 4 CHANGE ROADMAP

Section	Page No.	Type of Change[1]
VOLUME 1		
AP1000 Document Cover Sheet		Editorial
Design Control Document, Title Page		Editorial
DCD Introduction	Intro-7	420.012 (R1) Editorial
DCD Introduction	Intro-8	620.001 (R1)
Tier 1 List of Effective Pages	1 through 4	Editorial
Master T of C	i through vi	Editorial
Tier 1 Revision 4 Change Roadmap	xi	Editorial
2.5	2.5.2-2	420.046 (R1)
2.5	2.5.2-13 and 2.5.2-13a	420.046 (R1)
2.5	2.5.2-13b	Editorial
3.0	3.2-1 and 3.2-2	620.004 (R1)
3.0	3.3-20	620.004 (R1)
3.0	3.3-35	Technical

1. Changes incorporated as a result of Westinghouse responses to NRC Request for Additional Information (RAI) identified by RAI number.

TIER 1 REVISION 5 CHANGE ROADMAP

Section	**Page No.**	**Type of Change**[1]
VOLUME 1		
AP1000 Document Cover Sheet		Editorial
Design Control Document, Title Page		Editorial
Tier 1 List of Effective Pages	1 through 4	Editorial
Master T of C	i through vi	Editorial
Tier 1 Revision 5 Change Roadmap	xii	Editorial
2.2	2.2.1-5	Editorial
2.2	2.2.2-10	Editorial
2.2	2.2.2-11	Technical
2.2	2.2.2-14	Editorial
2.2	2.2.4-21	Editorial
2.2	2.2.5-11	Editorial
2.3	2.3.5-1 through 2.3.5-4	Technical
2.3	2.3.7-1	Editorial
2.7	2.7.3-4	Editorial
5.0	5.0-3 through 5.0-5	240.005

1. Changes incorporated as a result of Westinghouse responses to NRC Request for Additional Information (RAI) identified by RAI number.

TIER 1 REVISION 6 CHANGE ROADMAP

Section	Page No.	Type of Change
VOLUME 1		
AP1000 Document Cover Sheet		Editorial
Design Control Document, Title Page		Editorial
Tier 1 List of Effective Pages	1 through 4	Editorial
Master T of C	i through vi	Editorial
Tier 1 Revision 6 Change Roadmap	xiii	Editorial
2.2	2.2.2-13	Editorial
2.3	2.3.7-7	Editorial
3.2	3.2-1	Editorial
3.2	3.2-2	Editorial
3.2	3.2-9	Editorial

TIER 1 REVISION 7 CHANGE ROADMAP

Section	Page No.	Type of Change[1]
VOLUME 1		
AP1000 Document Cover Sheet		Editorial
Design Control Document, Title Page		Editorial
DCD Introduction	Intro-7	Editorial
DCD Introduction	Intro-10	Editorial
Tier 1 List of Effective Pages	1 through 4	Editorial
Master T of C	i through vi	Editorial
Tier 1 Revision 7 Change Roadmap	xiv and xv	Editorial
1.0	1.2-1 and 1.2-2	DSER OI 14.3.2-12 (R2)
2.1	2.1.2-27	Editorial
2.1	2.1.3-2	DSER OI 14.3.2-9 (R1)
2.1	2.1.3-9	DSER OI 14.3.2-9 (R1)
2.1	2.1.3-11	Editorial
2.2	2.2.1-1	DSER OI 14.3.2-2
2.2	2.2.1-11	DSER OI 14.3.2-2
2.2	2.2.2-11	DSER OI 14.2-1
2.2	2.2.3-22	Editorial
2.3	2.3.6-12	DSER OI 5.3.3-1
2.5	2.5.1-1	DSER OI 14.3.3-2 DSER OI 14.3.3-3
2.5	2.5.1-3	DSER OI 14.3.3-1
2.5	2.5.1-5	DSER OI 14.3.3-2
2.5	2.5.1-6	DSER OI 14.3.3-3
2.5	2.5.2-2	DSER OI 14.3.3-6
2.5	2.5.2-4	DSER OI 14.3.3-4
2.5	2.5.2-6	Editorial
2.5	2.5.2-7	DSER OI 14.3.3-5 (R1)
2.5	2.5.2-10	DSER OI 14.3.3-5 (R1) DSER OI 14.3.3-8
2.5	2.5.2-13	DSER OI 14.3.3-9 DSER OI 14.3.3-10
2.5	2.5.2-14	DSER OI 14.3.3-6

TIER 1 REVISION 7 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
2.6	2.6.5-1	DSER OI 14.3.3-17 (R1)
2.6	2.6.5-3	DSER OI 14.3.3-17 (R1) Editorial
2.7	2.7.1-1	DSER OI 13.3-1 (R1) DSER OI 14.3.3-17 (R1) Editorial
2.7	2.7.1-2	DSER OI 14.3.2-12 (R1) DSER OI 14.3.3-17 (R1) DSER OI 14.3.3-18
2.7	2.7.1-6	Editorial
2.7	2.7.1-7	DSER OI 14.3.3-18
2.7	2.7.1-8	DSER OI 14.3.2-12 (R1) DSER OI 14.3.3-17 (R1)
2.7	2.7.1-11	DSER OI 14.3.3-18
3.0	3.1-1 and 3.1-2	DSER OI 14.3.2-12 (R1)
3.0	3.2-5	DSER OI 14.3.3-11
3.0	3.7-1 through 3.7-5	DSER OI 14.3.2-15 (R1) Editorial
3.0	3.7-6	Editorial

1. Changes incorporated as a result of Draft Safety Evaluation Report (DSER) Open Item (OI) Response identified by DSER OI number.

TIER 1 REVISION 8 CHANGE ROADMAP

Section	Page No.	Type of Change[1]
VOLUME 1		
AP1000 Document Cover Sheet		Editorial
Design Control Document, Title Page		Editorial
Tier 1 List of Effective Pages	1 through 4	Editorial
Master T of C	i through vi	Editorial
Tier 1 Revision 8 Change Roadmap	xvi	Editorial
2.1	2.1.2-25	NRC Audit (Nov. 18-20) Action Item 3
2.1	2.1.2-26	Editorial
2.1	2.1.2-31	NRC Audit (Nov. 18-20) Action Item 4
2.2	2.2.3-18	NRC Audit Action Item 5
2.3	2.3.2-3	NRC CIP Team Comment
2.3	2.3.2-5	Editorial
2.3	2.3.2-6	NRC CIP Team Comment
2.3	2.3.2-14	NRC CIP Team Comment
2.3	2.3.6-12	DSER OI 5.3.3-1 (R2)
2.3	2.3.7-1	NRC CIP Team Comment
2.3	2.3.7-3 through 2.3.7-5	NRC CIP Team Comment
2.3	2.3.7-11	NRC CIP Team Comment
5.0	5.0-1	Editorial
5.0	5.0-3	DSER OI 2.5.4-2 (R2)

1. Changes incorporated as a result of Draft Safety Evaluation Report (DSER) Open Item (OI) Response identified by DSER OI number.

TIER 1 REVISION 9 CHANGE ROADMAP

Section	Page No.	Type of Change[(1)]
VOLUME 1		
AP1000 Document Cover Sheet		Editorial
Design Control Document, Title Page		Editorial
Tier 1 List of Effective Pages	1 through 4	Editorial
Master T of C	i through vi	Editorial
Tier 1 Revision 9 Change Roadmap	xvii	Editorial
2.2	2.2.3-21	DSER OI 6.2.1.8.3-3 (R2)
2.2	2.2.3-29	DSER OI 6.2.1.8.3-3 (R2)
2.3	2.3.6-5 and 2.3.6-6	Editorial
2.3	2.3.6-12	DSER OI 5.3.3-1 (R3)
2.4	2.4.7-1	DSER OI 14.3.3 - ITAAC Item
3.0	3.3-2	DSER OI 15.2.7-1 Item 7 (R4), Addendum
3.0	3.3-17	DSER OI 15.2.7-1 Item 7 (R4), Addendum
3.0	3.3-27	Technical
3.0	3.3-31	Technical
3.0	3.3-33	Technical
3.0	3.7-1	DSER OI CIP Issue 7
5.0	5.0-3	DSER OI 2.3.4-1 (R4)
5.0	5.0-4	DSER OI 14.3.4-1 (R1)

1. Changes incorporated as a result of Draft Safety Evaluation Report (DSER) Open Item (OI) Responses identified by DSER OI number.

TIER 1 REVISION 10 CHANGE ROADMAP

Section	Page No.	Type of Change[1]
VOLUME 1		
AP1000 Document Cover Sheet		Editorial
Design Control Document, Title Page		Editorial
DCD Introduction, T of C	i and ii	Editorial
DCD Introduction	Intro-7 through Intro-15	NRC Comments
DCD Introduction	Intro-16	Tier 2* for Piping DAC
Tier 1 List of Effective Pages	1 through 4	Editorial
Master T of C	i through vi	Editorial
Tier 1 Revision 10 Change Roadmap	xviii	Editorial
2.3	2.3.10-3	DSER OI 3.6.3.4-2 (R1) Addendum 2
5.0	5.0-3 and 5.0-4	DSER OI 15.3-1 (R4)

1. Changes incorporated as a result of Draft Safety Evaluation Report (DSER) Open Item (OI) Responses identified by DSER OI number.

TIER 1 REVISION 11 CHANGE ROADMAP

Section	Page No.	Type of Change[1]
VOLUME 1		
AP1000 Document Cover Sheet		Editorial
Design Control Document, Title Page		Editorial
DCD Introduction	Intro-7	NRC Comments
DCD Introduction	Intro-9	NRC Comments Editorial
DCD Introduction	Intro-12	NRC Comments
DCD Introduction	Intro-15	NRC Comments Editorial
DCD Introduction	Intro-16 and Intro-17	Tier 2* for Piping DAC
Tier 1 List of Effective Pages	1 through 4	Editorial
Master T of C	i through vi	Editorial
Tier 1 Revision 11 Change Roadmap	xix	Editorial
2.3	2.3.9-1	DSER OI 14.3.2-6 (R1)
2.3	2.3.9-6	DSER OI 14.3.2-6 (R1)
2.6	2.6.10-1	NRC Comments
2.6	2.6.11-1	NRC Comments
3.3	3.3-3 and 3.3-4	DSER OI May 6, 2004 Security Telecon
3.3	3.3-24	DSER OI May 6, 2004 Security Telecon

1. Changes incorporated as a result of Draft Safety Evaluation Report (DSER) Open Item (OI) Responses identified by DSER OI number.

TIER 1 REVISION 12 CHANGE ROADMAP

Section	Page No.	Type of Change[1]
VOLUME 1		
AP1000 Document Cover Sheet		Editorial
Design Control Document, Title Page		Editorial
Tier 1 List of Effective Pages	1 through 4	Editorial
Master T of C	i through vi	Editorial
Tier 1 Revision 12 Change Roadmap	xx	Editorial
5.0	5.0-3 and 5.0-4	DSER OI 15.3-1 (R5)

1. Changes incorporated as a result of Draft Safety Evaluation Report (DSER) Open Item (OI) Responses identified by DSER OI number.

TIER 1 REVISION 13 CHANGE ROADMAP

Section	Page No.	Type of Change[1]
VOLUME 1		
AP1000 Document Cover Sheet		Editorial
Design Control Document, Title Page		Editorial
Tier 1 List of Effective Pages	1 through 4	Editorial
Master T of C	i through vi	Editorial
Tier 1 Revision 13 Change Roadmap	xxi	Editorial
2.1	2.1.2-22	NRC Comments
2.1	2.1.3-8	NRC Comments
2.2	2.2.1-12	NRC Comments
2.2	2.2.1-14	Editorial
2.2	2.2.2-10	NRC Comments
2.2	2.2.3-17	NRC Comments
2.2	2.2.4-18	NRC Comments
2.3	2.3.2-9	NRC Comments
2.3	2.3.6-12	NRC Comments
2.3	2.3.13-6	NRC Comments
2.5	2.5.5-3	NRC Comments
3.5	3.5-5	NRC Comments

TIER 1 REVISION 14 CHANGE ROADMAP

Section	Page No.	Type of Change[1]
VOLUME 1		
AP1000 Document Cover Sheet		Editorial
Design Control Document, Title Page		Editorial
Tier 1 List of Effective Pages	1 through 4	Editorial
Master T of C	i through vi	Editorial
Tier 1 Revision 14 Change Roadmap	xxii	Editorial

TIER 1 REVISION 15 CHANGE ROADMAP

Section	Page No.	Type of Change[1]
VOLUME 1		
AP1000 Document Cover Sheet		Editorial
Design Control Document, Title Page		Editorial
Tier 1 List of Effective Pages	1 through 4	Editorial
Master T of C	i through vi	Editorial
Tier 1 Revision 15 Change Roadmap	xxiii through xxvi	Editorial
1.1	1.1-2	Editorial
1.2	1.2-1	Editorial
1.4	1.4-5	Editorial
2.1	2.1.1-2	Technical
2.1	2.1.2-2	Technical
2.1	2.1.2-4	Technical
2.1	2.1.2-8	Technical
2.1	2.1.2-13 through 2.1.2-20	Technical
2.1	2.1.2-22	Technical
2.1	2.1.2-25	Technical
2.1	2.1.2-30 and 2.1.2-31	Technical
2.1	2.1.2-32	Technical Editorial
2.1	2.1.3-3 and 2.1.3-4	Technical Editorial
2.1	2.1.3-7 through 2.1.3-9	Technical
2.1	2.1.3-10	Technical Editorial
2.1	2.1.3-12	Technical
2.1	2.1.3-15	Technical
2.2	2.2.1-6 through 2.2.1-9	Technical
2.2	2.2.1-12	Technical
2.2	2.2.1-15	Technical
2.2	2.2.2-1 and 2.2.2-2	Technical Editorial

TIER 1 REVISION 15 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
2.2	2.2.2-4 and 2.2.2-5	Technical Editorial
2.2	2.2.2-6	Editorial
2.2	2.2.2-7	Technical
2.2	2.2.2-8	Editorial
2.2	2.2.2-9 and 2.2.2-10	Technical Editorial
2.2	2.2.2-11	Technical
2.2	2.2.2-12 and 2.2.2-13	Technical Editorial
2.2	2.2.2-14	Technical
2.2	2.2.2-16	Technical
2.2	2.2.3-6	Technical
2.2	2.2.3-11	Technical
2.2	2.2.3-13	Technical
2.2	2.2.3-17	Technical
2.2	2.2.3-27	Technical
2.2	2.2.3-29	Technical
2.2	2.2.4-11 through 2.2.4-13	Editorial
2.2	2.2.4-18 and 2.2.4-19	Technical
2.2	2.2.4-22	Editorial
2.2	2.2.4-25	Editorial
2.2	2.2.5-1	Editorial
2.2	2.2.5-10	Technical
2.2	2.2.5-15	Editorial
2.3	2.3.1-3	Technical
2.3	2.3.2-1	Editorial
2.3	2.3.2-4	Technical
2.3	2.3.2-6 and 2.3.2-7	Technical Editorial
2.3	2.3.2-11	Technical
2.3	2.3.2-13	Technical
2.3	2.3.3-3	Editorial
2.3	2.3.4-3	Technical
2.3	2.3.4-6	Technical
2.3	2.3.6-1	Editorial
2.3	2.3.6-4 through 2.3.6-8	Editorial
2.3	2.3.6-10 and 2.3.6-11	Editorial
2.3	2.3.6-12 through 2.3.6-14	Technical
2.3	2.3.6-17	Editorial

TIER 1 REVISION 15 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
2.3	2.3.7-1	Technical Editorial
2.3	2.3.7-3	Editorial
2.3	2.3.7-4 and 2.3.7-5	Technical Editorial
2.3	2.3.7-6 through 2.3.7-8	Technical
2.3	2.3.8-5	Technical
2.3	2.3.10-4	Technical
2.3	2.3.10-6 and 2.3.10-7	Technical
2.3	2.3.13-2	Editorial
2.3	2.3.13-6	Technical
2.3	2.3.13-7	Editorial
2.3	2.3.14-2	Technical
2.3	2.3.15-2	Technical
2.5	2.5.2-12	Technical
2.5	2.5.3-1	Technical
2.5	2.5.4-1	Technical
2.5	2.5.4-4	Technical
2.5	2.5.5-4	Technical
2.6	2.6.1-8 and 2.6.1-9	Technical
2.6	2.6.3-8	Technical
2.6	2.6.5-2	Technical
2.7	2.7.1-7	Technical
2.7	2.7.1-9	Technical
2.7	2.7.2-3	Technical
2.7	2.7.2-5 and 2.7.2-6	Editorial
2.7	2.7.4-5 and 2.7.4-6	Editorial
2.7	2.7.5-3	Editorial
2.7	2.7.6-3	Technical Editorial
2.7	2.7.7-1	Editorial
3.2	3.2-6 through 3.2-8	Technical
3.3	3.3-2	Technical
3.3	3.3-5 through 3.3-11	Technical
3.3	3.3-19	Technical

TIER 1 REVISION 15 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
3.5	3.5-2	Technical Editorial
3.5	3.5-5	Technical
3.5	3.5-7	Technical
3.5	3.5-8	Technical
3.6	3.6-2	Technical
5.0	5.0-2	Editorial

1.0 Introduction

1.1 Definitions

The following definitions apply to terms used in the design descriptions and associated inspections, tests, analyses, and acceptance criteria (ITAAC).

Acceptance Criteria means the performance, physical condition, or analysis result for a structure, system, or component that demonstrates that the design commitment is met.

Analysis means a calculation, mathematical computation, or engineering or technical evaluation. Engineering or technical evaluations could include, but are not limited to, comparisons with operating experience or design of similar structures, systems, or components.

As-built means the physical properties of a structure, system, or component following the completion of its installation or construction activities at its final location at the plant site.

Column Line is the designation applied to a plant reference grid used to define the location of building walls and columns. Column lines may not represent the center line of walls and columns.

Design Commitment means that portion of the design description that is verified by ITAAC.

Design Description means that portion of the design that is certified.

Design Plant Grade means the elevation of the soil around the nuclear island assumed in the design of the AP1000, i.e., floor elevation 100'-0".

Division (for electrical systems or electrical equipment) is the designation applied to a given safety-related system or set of components that is physically, electrically, and functionally independent from other redundant sets of components.

Floor Elevation is the designation applied to name a floor. The actual elevation may vary due to floor slope and layout requirements.

Functional Arrangement (for a system) means the physical arrangement of systems and components to provide the service for which the system is intended, and which is described in the system design description.

Inspect or **Inspection** means visual observations, physical examinations, or reviews of records based on visual observation or physical examination that compare the structure, system, or component condition to one or more design commitments. Examples include walkdowns, configuration checks, measurements of dimensions, or nondestructive examinations.

Inspect for Retrievability of a display means to visually observe that the specified information appears on a monitor when summoned by the operator.

L_a is the maximum allowable containment leakage as defined in 10 CFR 50 Appendix J.

Physical Arrangement (for a structure) means the arrangement of the building features (e.g., floors, ceilings, walls, and basemat) and of the structures, systems, and components within, which are described in the building design description.

Qualified for Harsh Environment means that equipment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of its safety function, for the time required to perform the safety function. These environmental conditions include applicable time-dependent temperature and pressure profiles, humidity, chemical effects, radiation, aging, submergence, and their synergistic effects which have a significant effect on the equipment performance. Equipment identified in the Design Description as being Qualified for Harsh Environment includes the:

a. equipment itself
b. sensors, switches and lubricants that are an integral part of the equipment
c. electrical components connected to the equipment (wiring, cabling and terminations)

Items b and c are Qualified for Harsh Environment only when they are necessary to support operation of the equipment to meet its safety-related function listed in the Design Description table and to the extent such equipment is located in a harsh environment during or following a design basis accident.

Sensor means a transmitter, resistance temperature detector, thermocouple or other transducer, plus associated cables, connectors, preamplifiers, reference junction boxes, or other signal processing equipment that is located in the immediate proximity of the sensor and subject to the same environmental conditions.

Site Grade means the as-built elevation of the soil to the west side of the nuclear island. Adjacent buildings are located on the other sides of the nuclear island.

Tag Number in the ITAACs represents the complete tag number or a portion of the tag number used to identify the actual hardware (or associated software). For instrumentation, the tag number identified in the ITAACs does not include the type of instrument (for example, the Containment Exhaust Fan A Flow Sensor, VFS-11A, does not include the designators FE [flow element] or FT [flow transmitter], which would appear on the actual hardware or in the associated software). This is because the designator VFS-11A and the equipment description are sufficient to uniquely identify the channel associated with the designated instrument function, and this method of identification eliminates the need to list every portion of the instrumentation channel required to perform the function. In most cases, the channel number includes physical hardware. There are, however, a few places where the channel number represents only a calculation in software. In those cases, the channel data can be displayed. In many instances, the word "sensor" is used in the equipment description to identify that the item is an instrument.

Test means the actuation, operation, or establishment of specified conditions to evaluate the performance or integrity of as-built structures, systems, or components, unless explicitly stated otherwise.

Transfer Open (Closed) means to move from a closed (open) position to an open (closed) position.

Type Test means a test on one or more sample components of the same type and manufacturer to qualify other components of the same type and manufacturer. A type test is not necessarily a test of the as-built structures, systems, or components.

UA of a heat exchanger means the product of the heat transfer coefficient and the surface area.

1.2 General Provisions

The following general provisions are applicable to the design descriptions and associated ITAAC.

Treatment of Individual Items

The absence of any discussion or depiction of an item in the design description or accompanying figures shall not be construed as prohibiting a licensee from utilizing such an item, unless it would prevent an item from performing its safety functions as discussed or depicted in the design description or accompanying figures.

If an inspections, tests, or analyses (ITA) requirement does not specify the temperature or other conditions under which a test must be run, then the test conditions are not constrained.

When the term "operate," "operates," or "operation" is used with respect to an item discussed in the acceptance criteria, it refers to the actuation and running of the item. When the term "exist," "exists," or "existence" is used with respect to an item discussed in the acceptance criteria, it means that the item is present and meets the design commitment.

Implementation of ITAAC

The ITAACs are provided in tables with the following three-column format:

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria

Each design commitment in the left-hand column of the ITAAC tables has an associated ITA requirement specified in the middle column of the tables.

The identification of a separate ITA entry for each design commitment shall not be construed to require that separate inspections, tests, or analyses must be performed for each design commitment. Instead, the activities associated with more than one ITA entry may be combined, and a single inspection, test, or analysis may be sufficient to implement more than one ITA entry.

An ITA may be performed by the licensee of the plant or by its authorized vendors, contractors, or consultants. Furthermore, an ITA may be performed by more than a single individual or group, may be implemented through discrete activities separated by time, and may be performed at any time prior to fuel load (including before issuance of the combined license for those ITAACs that do not necessarily pertain to as-installed equipment). Additionally, an ITA may be performed as part of the activities that are required to be performed under 10 CFR Part 50 (including, for example, the quality assurance (QA) program required under Appendix B to Part 50); therefore, an ITA need not be performed as a separate or discrete activity.

Many of the acceptance criteria include the words “A report exists and concludes that…” When these words are used, it indicates that the ITAAC for that design commitment will be met when it is confirmed that appropriate documentation exists and the documentation shows that the design commitment is met. Appropriate documentation can be a single document or a collection of documents that show that the stated acceptance criteria are met. Examples of appropriate documentation include design reports, test reports,

inspection reports, analysis reports, evaluation reports, design and manufacturing procedures, certified data sheets, commercial dedication procedures and records, quality assurance records, calculation notes, and equipment qualification data packages.

Many entries in the ITA column of the ITAAC tables include the words "Inspection will be performed for the existence of a report verifying…" When these words are used it indicates that the ITA is tests, type tests, analyses, or a combination of tests, type tests, and analyses and a report will be produced documenting the results. This report will be available to inspectors.

Many ITAAC are only a reference to another Tier 1 location, either a section, subsection, or ITAAC table entry (for example, "See Tier 1 Material…"). A reference to another ITAAC location is always in both the ITA and acceptance criteria columns for a design commitment. This reference is an indication that the ITA and acceptance criteria for that design commitment are satisfied when the referenced ITA are completed and the acceptance criteria for the referenced Tier 1 sections, subsections, or table entries are satisfied. If a complete Tier 1 section is referenced, this indicates that all the ITA and acceptance criteria in that section must be met before the referencing design commitment is satisfied.

Discussion of Matters Related to Operations

In some cases, the design descriptions in this document refer to matters that relate to operation, such as normal valve or breaker alignment during normal operation modes. Such discussions are provided solely to place the design description provisions in context (for example, to explain automatic features for opening or closing valves or breakers upon off-normal conditions). Such discussions shall not be construed as requiring operators during operation to take any particular action (for example, to maintain valves or breakers in a particular position during normal operation).

Interpretation of Figures

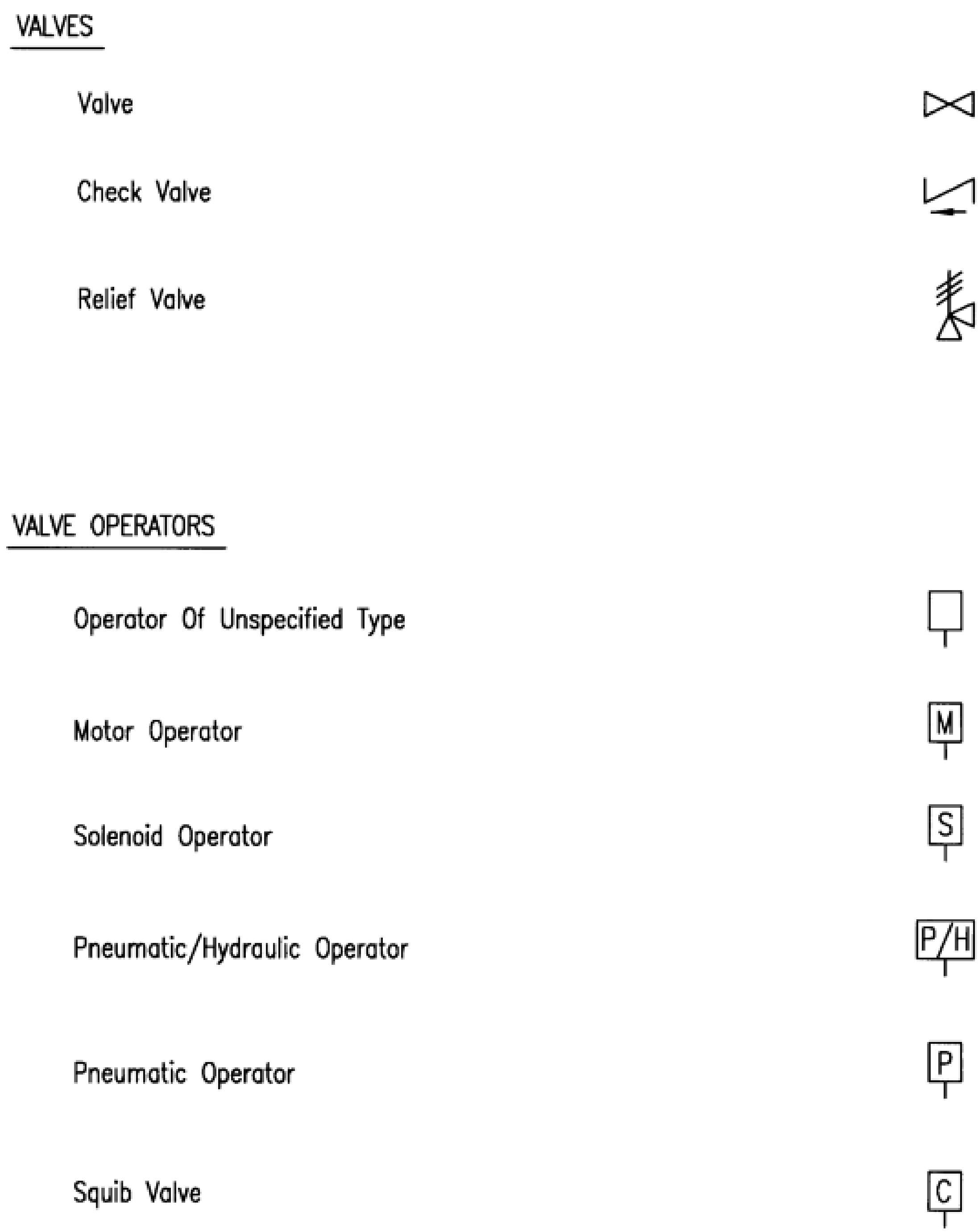
In many but not all cases, the design descriptions in Section 2 include one or more figures. The figures may represent a functional diagram, general structural representation, or another general illustration. For instrumentation and control (I&C) systems, figures may also represent aspects of the relevant logic of the system or part of the system. Unless specified explicitly, the figures are not indicative of the scale, location, dimensions, shape, or spatial relationships of as-built structures, systems, and components. In particular, the as-built attributes of structures, systems, and components may vary from the attributes depicted on the figures, provided that those safety functions discussed in the design description pertaining to the figure are not adversely affected.

Maximum Reactor Core Thermal Power

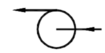
The initial rated reactor core thermal power for the AP1000 certified design is 3400 megawatts thermal (MWt).

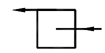
1.3 Figure Legend

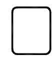
The conventions used in this section are for figures described in the design description. The figure legend is provided for information and is not part of the Tier 1 Material.



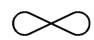
MECHANICAL EQUIPMENT

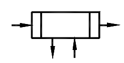
Centrifugal Pump 

Pump Type Not Specified 

Tank 

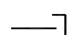
Centrifugal Fan 

Axial Fan 

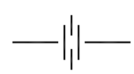
Heat Exchanger 

Vent 

Drain 

Pipe Cap 

Blind Flange 

Orifice 

DAMPERS

Gravity Or Manually Operated Damper 

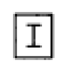
Remotely Operated Damper 

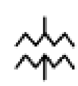
ELECTRICAL EQUIPMENT

Battery 

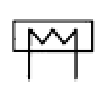
Circuit Breaker 

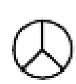
Disconnect Switch 

Isolation 

Transformer 

Fuse 

Heater 

Generator 

MISCELLANEOUS

A component that is part of the system functional arrangement shown on the figure and is included in the design commitments for the system. — Component Name / Component Tag No.

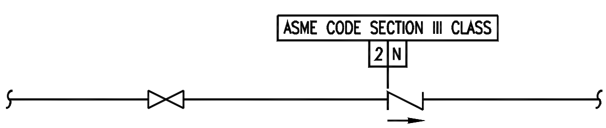
A component that is part of the system functional arrangement shown on the figure. — Component Name / Component Tag No.

A system or component of another system that is not part of the system functional arrangement shown on the figure. — System or Component Name / System Acronym

A functional connection to another system that is not part of the system functional arrangement shown on the figure. — SYSTEM ACRONYM

ASME CODE CLASS BREAK

An ASME Code class break is identified by a single line to the designated location for the class break, as shown in the example below (see note 1).



NOTES:

1. The header, "ASME Code Section III Class", must appear at least once on each figure on which ASME class breaks are shown, but need not appear at every class break shown on a figure.

N Indicates Non-ASME Code Section III

1.4 List of Acronyms and Abbreviations

The acronyms presented in this section are used in the Tier 1 Material. The acronyms are provided for information and are not part of the Tier 1 Material.

ac	Alternating Current
AC	Acceptance Criteria
ACC	Accumulator
ADS	Automatic Depressurization System
AHU	Air Handling Units
ASME	American Society of Mechanical Engineers
BTU	British Thermal Unit
CAS	Compressed Air System
CAV	Cumulative Absolute Velocity
CCS	Component Cooling Water System
CDM	Certified Design Material
CDS	Condensate System
CFR	Code of Federal Regulations
CIV	Containment Isolation Valve
CL	Cold Leg
CMT	Core Makeup Tank
CNS	Containment System
COL	Combined Operating License
CRDM	Control Rod Drive Mechanism
CST	Condensate Storage Tank
CVS	Chemical and Volume Control System
DAC	Design Acceptance Criteria
DAS	Diverse Actuation System
DBA	Design Basis Accident
dc	Direct Current
DC	Design Commitment
DDS	Data Display and Processing System
DOS	Standby Diesel and Auxiliary Boiler Fuel Oil System
DPU	Distributed Processing Unit
D-RAP	Design Reliability Assurance Program
DTS	Demineralized Water Treatment System
DVI	Direct Vessel Injection

List of Acronyms and Abbreviations (cont.)

DWS	Demineralized Water Transfer and Storage System
ECS	Main ac Power System
EDS	Non-Class 1E dc and Uninterruptible Power Supply System
EFS	Communication System
EGS	Grounding and Lightening Protection System
ELS	Plant Lighting System
EMI	Electromagnetic Interference
ERF	Emergency Response Facility
ESD	Electrostatic Discharge
ESF	Emergency Safety Features
ESFAS	Engineering Safety Feature Actuation System
F	Fahrenheit
FHM	Fuel Handling Machine
FHS	Fuel Handling and Refueling System
FID	Fixed Incore Detector
FPS	Fire Protection System
ft	Feet
FTS	Fuel Transfer System
FWS	Main and Startup Feedwater System
gpm	Gallons per Minute
HEPA	High Efficiency Particulate Air
HFE	Human Factors Engineering
HL	Hot Leg
hr	Hour
HSI	Human-System Interface
HVAC	Heating, Ventilation, and Air Conditioning
HX	Heat Exchanger
Hz	Hertz
I&C	Instrumentation and Control
IDS	Class 1E dc and Uninterruptible Power Supply System
IIS	In-core Instrumentation System
ILRT	Integrated Leak Rate Test
IHP	Integrated Head Package
in	Inches
I/O	Input/Output

List of Acronyms and Abbreviations (cont.)

I&C	Instrumentation and Control
IRC	Inside Reactor Containment
IRWST	In-containment Refueling Water Storage Tank
ISI	Inservice Inspection
IST	Inservice Testing
ITA	Inspections, Tests, Analyses
ITAAC	Inspections, Tests, Analyses, and Acceptance Criteria
LBB	Leak Before Break
LTOP	Low Temperature Overpressure Protection
Mbtu	Million British Thermal Units
MCC	Motor Control Center
MCR	Main Control Room
MHS	Mechanical Handling System
MMIS	Man-machine Interface System
MOV	Motor-operated Valve
MSIV	Main Steam Isolation Valve
MSLB	Main Steam Line Break
MSS	Main Steam System
MTS	Main Turbine System
MW	Megawatt
MWe	Megawatt Electric
MWt	Megawatt Thermal
N/A	Not Applicable
NDE	Nondestructive Examination
NI	Nuclear Island
NSSS	Nuclear Steam Supply System
OCS	Operation and Control Centers System
ORC	Outside Reactor Containment
ORE	Occupational Radiation Exposure
OSA	Operational Sequence Analyses
OSC	Operations Support Center
PAR	Passive Autocatalytic Recombiner
PCCAWS	Passive Containment Cooling Ancillary Water Storage Tank
PCWS	Passive Containment Cooling Water Storage
PCCWST	Passive Containment Cooling Water Storage Tank

List of Acronyms and Abbreviations (cont.)

PCS	Passive Containment Cooling System
P&ID	Piping and Instrument Diagram
PGS	Plant Gas System
pH	Potential of Hydrogen
PLS	Plant Control System
PMS	Protection and Safety Monitoring System
PORV	Power-operated Relief Valve
PRA	Probabilistic Risk Assessment
PRHR	Passive Residual Heat Removal
psia	Pounds per Square Inch Absolute
PSS	Primary Sampling System
PXS	Passive Core Cooling System
PWR	Pressurized Water Reactor
RAP	Reliability Assurance Program
RAT	Reserve Auxiliary Transformer
RCDT	Reactor Coolant Drain Tank
RCP	Reactor Coolant Pump
RCPB	Reactor Coolant Pressure Boundary
RCS	Reactor Coolant System
RFI	Radio Frequency Interference
RM	Refueling Machine
RMS	Radiation Monitoring System
RNS	Normal Residual Heat Removal System
RPV	Reactor Pressure Vessel
RSR	Remote Shutdown Room
RSW	Remote Shutdown Workstation
RTD	Resistance Temperature Detector
RXS	Reactor System
RV	Reactor Vessel
scf	Standard Cubic Feet
scfm	Standard Cubic Feet per Minute
SFP	Spent Fuel Pool
SFS	Spent Fuel Pool Cooling System
SG	Steam Generator
SGS	Steam Generator System

List of Acronyms and Abbreviations (cont.)

SJS	Seismic Monitoring System
SMS	Special Monitoring System
SSAR	Standard Safety Analysis Report
SSCs	Structures, Systems, and Components
SSE	Safe Shutdown Earthquake
SWC	Surge Withstand Capability
SWS	Service Water System
TID	Total Integrated Dose
TSC	Technical Support Center
UAT	Unit Auxiliary Transformer
UBC	Uniform Building Code
UPS	Uninterruptible Power Supply
V	Volt
VAS	Radiologically Controlled Area Ventilation System
VBS	Nuclear Island Nonradioactive Ventilation System
VCS	Containment Recirculation Cooling System
VES	Main Control Room Emergency Habitability System
VFS	Containment Air Filtration System
VHS	Health Physics and Hot Machine Shop Areas
VLS	Containment Hydrogen Control System
VWS	Central Chilled Water System
VXS	Annex/Auxiliary Building Nonradioactive Ventilation System
VZS	Diesel Generator Building Ventilation System
WGS	Gaseous Radwaste System
WLS	Liquid Radwaste System
WSS	Solid Radwaste System
ZOS	Onsite Standby Power System

2.1.1 Fuel Handling and Refueling System

Design Description

The fuel handling and refueling system (FHS) transfers fuel assemblies and core components during fueling operations and stores new and spent fuel assemblies in the new and spent fuel storage racks. The refueling machine (RM) and the fuel transfer tube are operated during refueling mode. The fuel handling machine (FHM) is operated during normal modes of plant operation, including startup, power operation, cooldown, shutdown and refueling.

The component locations of the FHS are as shown in Table 2.1.1-2.

1. The functional arrangement of the FHS is as described in the Design Description of this Section 2.1.1.

2. The FHS has the RM, the FHM, and the new and spent fuel storage racks.

3. The FHS preserves containment integrity by isolation of the fuel transfer tube penetrating containment.

4. The RM and FHM gripper assemblies are designed to prevent opening while the weight of the fuel assembly is suspended from the gripper.

5. The lift height of the RM and FHM masts is limited such that the minimum required depth of water shielding is maintained.

6. The RM and FHM are designed to maintain their load carrying and structural integrity functions during a safe shutdown earthquake.

7. The new and spent fuel storage racks maintain the effective neutron multiplication factor less than the required limits during normal operation, design basis seismic events, and design basis dropped fuel assembly accidents.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.1.1-1 specifies the inspections, tests, analyses, and associated acceptance criteria for the FHS.

Table 2.1.1-1
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the FHS is as described in the Design Description of this Section 2.1.1.	Inspection of the as-built system will be performed.	The as-built FHS conforms with the functional arrangement as described in the Design Description of this Section 2.1.1.
2. The FHS has the refueling machine (RM), the fuel handling machine (FHM), and the new and spent fuel storage racks.	Inspection of the system will be performed.	The FHS has the RM, the FHM, and the new and spent fuel storage racks.
3. The FHS preserves containment integrity by isolation of the fuel transfer tube penetrating containment.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.
4. The RM and FHM gripper assemblies are designed to prevent opening while the weight of the fuel assembly is suspended from the gripper.	The RM and FHM will be tested by operating the open controls of the gripper while suspending a dummy fuel assembly.	The gripper will not open while suspending a dummy test assembly.
5. The lift height of the RM and FHM masts is limited such that the minimum required depth of water shielding is maintained.	The RM and FHM will be tested by attempting to raise a dummy fuel assembly.	The bottom of the dummy fuel assembly cannot be raised to within 26 ft, 1 in of the operating deck floor.
6. The RM and FHM are designed to maintain their load carrying and structural integrity functions during a safe shutdown earthquake.	i) Inspection will be performed to verify that the RM and FHM are located on the nuclear island. ii) Type test, analysis, or a combination of type tests and analyses of the RM and FHM will be performed.	i) The RM and FHM are located on the nuclear island. ii) A report exists and concludes that the RM and FHM can withstand seismic design basis dynamic loads without loss of load carrying or structural integrity functions.

Table 2.1.1-1 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7. The new and spent fuel storage racks maintain the effective neutron multiplication factor less than the required limits during normal operation, design basis seismic events, and design basis dropped fuel assembly accidents.	i) Analyses will be performed to calculate the effective neutron multiplication factor in the new and spent fuel storage racks during normal conditions.	i) The calculated effective neutron multiplication factor for the new and spent fuel storage racks is less than 0.95 under normal conditions.
	ii) Inspection will be performed to verify that the new and spent fuel storage racks are located on the nuclear island.	ii) The new and spent fuel storage racks are located on the nuclear island.
	iii) Seismic analysis of the new and spent fuel storage racks will be performed.	iii) A report exists and concludes that the new and spent fuel racks can withstand seismic design basis dynamic loads and maintain the calculated effective neutron multiplication factor less than 0.95.
	iv) Analysis of the new and spent fuel storage racks under design basis dropped fuel assembly loads will be performed.	iv) A report exists and concludes that the new and spent fuel racks can withstand design basis dropped fuel assembly loads and maintain the calculated effective neutron multiplication factor less than 0.95.

Table 2.1.1-2		
Component Name	**Tag No.**	**Component Location**
Refueling Machine	FHS-FH-01	Containment
Fuel Handling Machine	FHS-FH-02	Auxiliary Building
Spent Fuel Storage Racks	FHS-FS-20	Auxiliary Building
New Fuel Storage Racks	FHS-FS-01	Auxiliary Building
Fuel Transfer Tube	FHS-FT-01	Auxiliary Building/Containment

2.1.2 Reactor Coolant System

Design Description

The reactor coolant system (RCS) removes heat from the reactor core and transfers it to the secondary side of the steam generators for power generation. The RCS contains two vertical U-tube steam generators, four canned motor reactor coolant pumps (RCPs), and one pressurizer.

The RCS is as shown in Figure 2.1.2-1 and the component locations of the RCS are as shown in Table 2.1.2-5.

1. The functional arrangement of the RCS is as described in the Design Description of this Section 2.1.2.

2. a) The components identified in Table 2.1.2-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.

   b) The piping identified in Table 2.1.2-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.

3. a) Pressure boundary welds in components identified in Table 2.1.2-1 as ASME Code Section III meet ASME Code Section III requirements.

   b) Pressure boundary welds in piping identified in Table 2.1.2-2 as ASME Code Section III meet ASME Code Section III requirements.

4. a) The components identified in Table 2.1.2-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.

   b) The piping identified in Table 2.1.2-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.

5. a) The seismic Category I equipment identified in Table 2.1.2-1 can withstand seismic design basis loads without loss of safety function.

   b) Each of the lines identified in Table 2.1.2-2 for which functional capability is required is designed to withstand combined normal and seismic design basis loads without a loss of its functional capability.

6. Each of the as-built lines identified in Table 2.1.2-2 as designed for leak before break (LBB) meets the LBB criteria, or an evaluation is performed of the protection from the dynamic effects of a rupture of the line.

7. a) The Class 1E equipment identified in Table 2.1.2-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.

b) The Class 1E components identified in Table 2.1.2-1 are powered from their respective Class 1E division.

c) Separation is provided between RCS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.

8. The RCS provides the following safety-related functions:

a) The pressurizer safety valves provide overpressure protection in accordance with Section III of the ASME Boiler and Pressure Vessel Code.

b) The reactor coolant pumps (RCPs) have a rotating inertia to provide RCS flow coastdown on loss of power to the pumps.

c) Each RCP flywheel assembly can withstand a design overspeed condition.

d) The RCS provides automatic depressurization during design basis events.

e) The RCS provides emergency letdown during design basis events.

9. The RCS provides the following nonsafety-related functions:

a) The RCS provides circulation of coolant to remove heat from the core.

b) The RCS provides the means to control system pressure.

c) The pressurizer heaters trip after a signal is generated by the PMS.

10. Safety-related displays identified in Table 2.1.2-1 can be retrieved in the main control room (MCR).

11. a) Controls exist in the MCR to cause the remotely operated valves identified in Table 2.1.2-1 to perform active functions.

b) The valves identified in Table 2.1.2-1 as having protection and safety monitoring system (PMS) control perform an active safety function after receiving a signal from the PMS.

c) The valves identified in Table 2.1.2-1 as having diverse actuation system (DAS) control perform an active safety function after receiving a signal from DAS.

12. a) The valves identified in Table 2.1.2-1 perform an active safety-related function to change position as indicated in the table.

b) After loss of motive power, the remotely operated valves identified in Table 2.1.2-1 assume the indicated loss of motive power position.

13. a) Controls exist in the MCR to trip the RCPs.

    b) The RCPs trip after receiving a signal from the PMS.

    c) The RCPs trip after receiving a signal from the DAS.

14. Controls exist in the MCR to cause the components identified in Table 2.1.2-3 to perform the listed function.

15. Displays of the parameters identified in Table 2.1.2-3 can be retrieved in the MCR.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.1.2-4 specifies the inspections, tests, analyses, and associated acceptance criteria for the RCS.

Table 2.1.2-1									
Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS/ DAS	Active Function	Loss of Motive Power Position
Steam Generator 1	RCS-MB-01	Yes	Yes	-	-/-	-	-	-	-
Steam Generator 2	RCS-MB-02	Yes	Yes	-	-/-	-	-	-	-
RCP 1A	RCS-MP-01A	Yes	Yes	-	No/No	No	Yes/Yes (pump trip)	No	-
RCP 1B	RCS-MP-01B	Yes	Yes	-	No/No	No	Yes/Yes (pump trip)	No	-
RCP 2A	RCS-MP-02A	Yes	Yes	-	No/No	No	Yes/Yes (pump trip)	No	-
RCP 2B	RCS-MP-02B	Yes	Yes	-	No/No	No	Yes/Yes (pump trip)	No	-
Pressurizer	RCS-MV-02	Yes	Yes	-	No/No (heaters) -/-	-	Yes/No (heater trip) -/-	No	-
Automatic Depressurization System (ADS) Sparger A	PXS-MW-01A	Yes	Yes	-	-/-	-	-/-	-	-
ADS Sparger B	PXS-MW-01B	Yes	Yes	-	-/-	-	-/-	-	-

Note: Dash (-) indicates not applicable.

Table 2.1.2-1 (cont.)

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS/ DAS	Active Function	Loss of Motive Power Position
Pressurizer Safety Valve	RCS-PL-V005A	Yes	Yes	No	-/-	No	-/-	Transfer Open/ Transfer Closed	-
Pressurizer Safety Valve	RCS-PL-V005B	Yes	Yes	No	-/-	No	-/-	Transfer Open/ Transfer Closed	-
First-stage ADS Motor-operated Valve (MOV)	RCS-PL-V001A	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/Yes	Transfer Open	As Is
First-stage ADS MOV	RCS-PL-V001B	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/Yes	Transfer Open	As Is
Second-stage ADS MOV	RCS-PL-V002A	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/Yes	Transfer Open	As Is
Second-stage ADS MOV	RCS-PL-V002B	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/Yes	Transfer Open	As Is
Third-stage ADS MOV	RCS-PL-V003A	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/Yes	Transfer Open	As Is

Note: Dash (-) indicates not applicable.

Table 2.1.2-1 (cont.)

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS/ DAS	Active Function	Loss of Motive Power Position
Third-stage ADS MOV	RCS-PL-V003B	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/Yes	Transfer Open	As Is
Fourth-stage ADS Squib Valve	RCS-PL-V004A	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	As Is
Fourth-stage ADS Squib Valve	RCS-PL-V004B	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	As Is
Fourth-stage ADS Squib Valve	RCS-PL-V004C	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	As Is
Fourth-stage ADS Squib Valve	RCS-PL-V004D	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	As Is
First-stage ADS Isolation MOV	RCS-PL-V011A	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/Yes	Transfer Open	As Is
First-stage ADS Isolation MOV	RCS-PL-V011B	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/Yes	Transfer Open	As Is
Second-stage ADS Isolation MOV	RCS-PL-V012A	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/Yes	Transfer Open	As Is
Second-stage ADS Isolation MOV	RCS-PL-V012B	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/Yes	Transfer Open	As Is

Note: Dash (-) indicates not applicable.

Table 2.1.2-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS/ DAS**	**Active Function**	**Loss of Motive Power Position**
Third-stage ADS Isolation MOV	RCS-PL-V013A	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/Yes	Transfer Open	As Is
Third-stage ADS Isolation MOV	RCS-PL-V013B	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/Yes	Transfer Open	As Is
Fourth-stage ADS MOV	RCS-PL-V014A	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/No	None	As Is
Fourth-stage ADS MOV	RCS-PL-V014B	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/No	None	As Is
Fourth-stage ADS MOV	RCS-PL-V014C	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/No	None	As Is
Fourth-stage ADS MOV	RCS-PL-V014D	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/No	None	As Is
Reactor Vessel Head Vent Valve	RCS-PL-V150A	Yes	Yes	Yes	Yes/Yes	No	Yes/No	Transfer Open	Closed
Reactor Vessel Head Vent Valve	RCS-PL-V150B	Yes	Yes	Yes	Yes/Yes	No	Yes/No	Transfer Open	Closed
Reactor Vessel Head Vent Valve	RCS-PL-V150C	Yes	Yes	Yes	Yes/Yes	No	Yes/No	Transfer Open	Closed
Reactor Vessel Head Vent Valve	RCS-PL-V150D	Yes	Yes	Yes	Yes/Yes	No	Yes/No	Transfer Open	Closed

Note: Dash (-) indicates not applicable.

Table 2.1.2-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS/ DAS**	**Active Function**	**Loss of Motive Power Position**
RCS Hot Leg 1 Flow Sensor	RCS-101A	-	Yes	-	Yes/No	No	-/-	-	-
RCS Hot Leg 1 Flow Sensor	RCS-101B	-	Yes	-	Yes/No	No	-/-	-	-
RCS Hot Leg 1 Flow Sensor	RCS-101C	-	Yes	-	Yes/No	No	-/-	-	-
RCS Hot Leg 1 Flow Sensor	RCS-101D	-	Yes	-	Yes/No	No	-/-	-	-
RCS Hot Leg 2 Flow Sensor	RCS-102A	-	Yes	-	Yes/No	No	-/-	-	-
RCS Hot Leg 2 Flow Sensor	RCS-102B	-	Yes	-	Yes/No	No	-/-	-	-
RCS Hot Leg 2 Flow Sensor	RCS-102C	-	Yes	-	Yes/No	No	-/-	-	-
RCS Hot Leg 2 Flow Sensor	RCS-102D	-	Yes	-	Yes/No	No	-/-	-	-
RCS Cold Leg 1A Narrow Range Temperature Sensor	RCS-121A	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Cold Leg 1B Narrow Range Temperature Sensor	RCS-121B	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Cold Leg 1B Narrow Range Temperature Sensor	RCS-121C	-	Yes	-	Yes/Yes	No	-/-	-	-

Note: Dash (-) indicates not applicable.

Table 2.1.2-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS/ DAS**	**Active Function**	**Loss of Motive Power Position**
RCS Cold Leg 1A Narrow Range Temperature Sensor	RCS-121D	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Cold Leg 2B Narrow Range Temperature Sensor	RCS-122A	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Cold Leg 2A Narrow Range Temperature Sensor	RCS-122B	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Cold Leg 2A Narrow Range Temperature Sensor	RCS-122C	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Cold Leg 2B Narrow Range Temperature Sensor	RCS-122D	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Cold Leg 1A Dual Range Temperature Sensor	RCS-125A	-	Yes	-	Yes/Yes	Yes (Wide Range)	-/-	-	-
RCS Cold Leg 2A Dual Range Temperature Sensor	RCS-125B	-	Yes	-	Yes/Yes	Yes (Wide Range)	-/-	-	-
RCS Cold Leg 1B Dual Range Temperature Sensor	RCS-125C	-	Yes	-	Yes/Yes	Yes (Wide Range	-/-	-	-
RCS Cold Leg 2B Dual Range Temperature Sensor	RCS-125D	-	Yes	-	Yes/Yes	Yes (Wide Range)	-/-	-	-

Note: Dash (-) indicates not applicable.

Table 2.1.2-1 (cont.)

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS/ DAS	Active Function	Loss of Motive Power Position
RCS Hot Leg 1 Narrow Range Temperature Sensor	RCS-131A	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Hot Leg 2 Narrow Range Temperature Sensor	RCS-131B	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Hot Leg 1 Narrow Range Temperature Sensor	RCS-131C	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Hot Leg 2 Narrow Range Temperature Sensor	RCS-131D	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Hot Leg 1 Narrow Range Temperature Sensor	RCS-132A	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Hot Leg 2 Narrow Range Temperature Sensor	RCS-132B	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Hot Leg 1 Narrow Range Temperature Sensor	RCS-132C	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Hot Leg 2 Narrow Range Temperature Sensor	RCS-132D	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Hot Leg 1 Narrow Range Temperature Sensor	RCS-133A	-	Yes	-	Yes/Yes	No	-/-	-	-

Note: Dash (-) indicates not applicable.

Table 2.1.2-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS/ DAS**	**Active Function**	**Loss of Motive Power Position**
RCS Hot Leg 2 Narrow Range Temperature Sensor	RCS-133B	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Hot Leg 1 Narrow Range Temperature Sensor	RCS-133C	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Hot Leg 2 Narrow Range Temperature Sensor	RCS-133D	-	Yes	-	Yes/Yes	No	-/-	-	-
RCS Hot Leg 1 Wide Range Temperature Sensor	RCS-135A	-	Yes	-	Yes/Yes	Yes	-/-	-	-
RCS Hot Leg 2 Wide Range Temperature Sensor	RCS-135B	-	Yes	-	Yes/Yes	Yes	-/-	-	-
RCS Wide Range Pressure Sensor	RCS-140A	-	Yes	-	Yes/Yes	Yes	-/-	-	-
RCS Wide Range Pressure Sensor	RCS-140B	-	Yes	-	Yes/Yes	Yes	-/-	-	-
RCS Wide Range Pressure Sensor	RCS-140C	-	Yes	-	Yes/Yes	Yes	-/-	-	-
RCS Wide Range Pressure Sensor	RCS-140D	-	Yes	-	Yes/Yes	Yes	-/-	-	-
RCS Hot Leg 1 Level Sensor	RCS-160A	-	Yes	-	Yes/Yes	Yes	-/-	-	-

Note: Dash (-) indicates not applicable.

Table 2.1.2-1 (cont.)

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS/ DAS	Active Function	Loss of Motive Power Position
RCS Hot Leg 2 Level Sensor	RCS-160B	-	Yes	-	Yes/Yes	Yes	-/-	-	-
Passive Residual Heat Removal (PRHR) Return Line Temperature Sensor	RCS-161	-	Yes	-	Yes/Yes	Yes	-/-	-	-
Pressurizer Pressure Sensor	RCS-191A	-	Yes	-	Yes/Yes	Yes	-/-	-	-
Pressurizer Pressure Sensor	RCS-191B	-	Yes	-	Yes/Yes	Yes	-/-	-	-
Pressurizer Pressure Sensor	RCS-191C	-	Yes	-	Yes/Yes	Yes	-/-	-	-
Pressurizer Pressure Sensor	RCS-191D	-	Yes	-	Yes/Yes	Yes	-/-	-	-
Pressurizer Level Reference Leg Temperature Sensor	RCS-193A	-	Yes	-	Yes/Yes	Yes	-/-	-	-
Pressurizer Level Reference Leg Temperature Sensor	RCS-193B	-	Yes	-	Yes/Yes	Yes	-/-	-	-
Pressurizer Level Reference Leg Temperature Sensor	RCS-193C	-	Yes	-	Yes/Yes	Yes	-/-	-	-

Note: Dash (-) indicates not applicable.

Table 2.1.2-1 (cont.)									
Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS/ DAS	Active Function	Loss of Motive Power Position
Pressurizer Level Reference Leg Temperature Sensor	RCS-193D	-	Yes	-	Yes/Yes	Yes	-/-	-	-
Pressurizer Level Sensor	RCS-195A	-	Yes	-	Yes/Yes	Yes	-/-	-	-
Pressurizer Level Sensor	RCS-195B	-	Yes	-	Yes/Yes	Yes	-/-	-	-
Pressurizer Level Sensor	RCS-195C	-	Yes	-	Yes/Yes	Yes	-/-	-	-
Pressurizer Level Sensor	RCS-195D	-	Yes	-	Yes/Yes	Yes	-/-	-	-
RCP 1A Bearing Water Temperature Sensor	RCS-211A	-	Yes	-	Yes/Yes	No	-/-	-	-
RCP 1A Bearing Water Temperature Sensor	RCS-211B	-	Yes	-	Yes/Yes	No	-/-	-	-
RCP 1A Bearing Water Temperature Sensor	RCS-211C	-	Yes	-	Yes/Yes	No	-/-	-	-
RCP 1A Bearing Water Temperature Sensor	RCS-211D	-	Yes	-	Yes/Yes	No	-/-	-	-
RCP 1B Bearing Water Temperature Sensor	RCS-212A	-	Yes	-	Yes/Yes	No	-/-	-	-

Note: Dash (-) indicates not applicable.

Table 2.1.2-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS/ DAS**	**Active Function**	**Loss of Motive Power Position**
RCP 1B Bearing Water Temperature Sensor	RCS-212B	-	Yes	-	Yes/Yes	No	-/-	-	-
RCP 1B Bearing Water Temperature Sensor	RCS-212C	-	Yes	-	Yes/Yes	No	-/-	-	-
RCP 1B Bearing Water Temperature Sensor	RCS-212D	-	Yes	-	Yes/Yes	No	-/-	-	-
RCP 2A Bearing Water Temperature Sensor	RCS-213A	-	Yes	-	Yes/Yes	No	-/-	-	-
RCP 2A Bearing Water Temperature Sensor	RCS-213B	-	Yes	-	Yes/Yes	No	-/-	-	-
RCP 2A Bearing Water Temperature Sensor	RCS-213C	-	Yes	-	Yes/Yes	No	-/-	-	-
RCP 2A Bearing Water Temperature Sensor	RCS-213D	-	Yes	-	Yes/Yes	No	-/-	-	-
RCP 2B Bearing Water Temperature Sensor	RCS-214A	-	Yes	-	Yes/Yes	No	-/-	-	-
RCP 2B Bearing Water Temperature Sensor	RCS-214B	-	Yes	-	Yes/Yes	No	-/-	-	-

Note: Dash (-) indicates not applicable.

Table 2.1.2-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS/ DAS**	**Active Function**	**Loss of Motive Power Position**
RCP 2B Bearing Water Temperature Sensor	RCS-214C	-	Yes	-	Yes/Yes	No	-/-	-	-
RCP 2B Bearing Water Temperature Sensor	RCS-214D	-	Yes	-	Yes/Yes	No	-/-	-	-
RCP 1A Pump Speed Sensor	RCS-281	-	Yes	-	Yes/Yes	No	-/-	-	-
RCP 1B Pump Speed Sensor	RCS-282	-	Yes	-	Yes/Yes	No	-/-	-	-
RCP 2A Pump Speed Sensor	RCS-283	-	Yes	-	Yes/Yes	No	-/-	-	-
RCP 2B Pump Speed Sensor	RCS-284	-	Yes	-	Yes/Yes	No	-/-	-	-

Note: Dash (-) indicates not applicable.

Table 2.1.2-2				
Line Name	**Line Number**	**ASME Code Section III**	**Leak Before Break**	**Functional Capability Required**
Hot Legs	RCS-L001A RCS-L001B	Yes	Yes	Yes
Cold Legs	RCS-L002A RCS-L002B RCS-L002C RCS-L002D	Yes	Yes	Yes
Pressurizer Surge Line	RCS-L003	Yes	Yes	Yes
ADS Inlet Headers	RCS-L004A/B RCS-L006A/B RCS-L030A/B RCS-L020A/B	Yes	Yes	Yes
Safety Valve Inlet Piping	RCS-L005A RCS-L005B	Yes	Yes	Yes
Safety Valve Discharge Piping	RCS-L050A/B RCS-L051A/B	Yes	No	Yes
ADS First-stage Valve Inlet Piping	RCS-L010A/B RCS-L011A/B	Yes	No	Yes
ADS Second-stage Valve Inlet Piping	RCS-L021A/B RCS-L022A/B	Yes	Yes No	Yes
ADS Third-stage Valve Inlet Piping	RCS-L131 RCS-L031A/B RCS-L032A/B	Yes	Yes Yes No	Yes
ADS Outlet Piping	RCS-L012A/B RCS-L023A/B RCS-L033A/B RCS-L061A/B RCS-L063A/B RCS-L064A/B RCS-L200 RCS-L069A/B RCS-L240A/B PXS-L130A/B	Yes	No	Yes
ADS Fourth-stage Inlet Piping	RCS-L133A/B RCS-L135A/B RCS-L136A/B RCS-L137A/B	Yes	Yes	Yes

Table 2.1.2-2 (cont.)				
Line Name	**Line Number**	**ASME Code Section III**	**Leak Before Break**	**Functional Capability Required**
Pressurizer Spray Piping	RCS-L106 RCS-L110A/B RCS-L212A/B RCS-L213 RCS-L215	Yes	No	No
RNS Suction Piping	RCS-L139 RCS-L140	Yes	Yes	No
CVS Purification Piping	RCS-L111 RCS-L112	Yes	No	No

Table 2.1.2-3			
Equipment	**Tag No.**	**Display**	**Control Function**
RCP 1A Breaker (Status)	ECS-ES-31	Yes	-
RCP 1A Breaker (Status)	ECS-ES-32	Yes	-
RCP 1B Breaker (Status)	ECS-ES-41	Yes	-
RCP 1B Breaker (Status)	ECS-ES-42	Yes	-
RCP 2A Breaker (Status)	ECS-ES-51	Yes	-
RCP 2A Breaker (Status)	ECS-ES-52	Yes	-
RCP 2B Breaker (Status)	ECS-ES-61	Yes	-
RCP 2B Breaker (Status)	ECS-ES-62	Yes	-
Pressurizer Heaters	RCS-EH-03	Yes	On/Off
Pressurizer Heaters	RCS-EH-04A	Yes	On/Off
Pressurizer Heaters	RCS-EH-04B	Yes	On/Off
Pressurizer Heaters	RCS-EH-04C	Yes	On/Off
Pressurizer Heaters	RCS-EH-04D	Yes	On/Off
Fourth-stage ADS Squib Valve (Position Indication)	RCS-PL-V004A	Yes	-
Fourth-stage ADS Squib Valve (Position Indication)	RCS-PL-V004B	Yes	-
Fourth-stage ADS Squib Valve (Position Indication)	RCS-PL-V004C	Yes	-
Fourth-stage ADS Squib Valve (Position Indication)	RCS-PL-V004D	Yes	-
Pressurizer Safety Valve (Position Indication)	RCS-PL-V005A	Yes	-
Pressurizer Safety Valve (Position Indication)	RCS-PL-V005B	Yes	-
Pressurizer Spray Valve (Position Indication)	RCS-PL-V110A	Yes	-

Note: Dash (-) indicates not applicable.

Table 2.1.2-3 (cont.)			
Equipment	**Tag No.**	**Display**	**Control Function**
Pressurizer Spray Valve (Position Indication)	RCS-PL-V110B	Yes	-
Reactor Vessel Head Vent Valve (Position Indication)	RCS-PL-V150A	Yes	-
Reactor Vessel Head Vent Valve (Position Indication)	RCS-PL-V150B	Yes	-
Reactor Vessel Head Vent Valve (Position Indication)	RCS-PL-V150C	Yes	-
Reactor Vessel Head Vent Valve (Position Indication)	RCS-PL-V150D	Yes	-

Note: Dash (-) indicates not applicable.

Table 2.1.2-4
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the RCS is as described in the Design Description of this Section 2.1.2.	Inspection of the as-built system will be performed.	The as-built RCS conforms with the functional arrangement described in the Design Description of this Section 2.1.2.
2.a) The components identified in Table 2.1.2-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built components as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built components identified in Table 2.1.2-1 as ASME Code Section III.
2.b) The piping identified in Table 2.1.2-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built components as documented in the ASME design reports.	The ASME code Section III design reports exist for the as-built piping identified in Table 2.1.2-2 as ASME Code Section III.
3.a) Pressure boundary welds in components identified in Table 2.1.2-1 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
3.b) Pressure boundary welds in piping identified in Table 2.1.2-2 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
4.a) The components identified in Table 2.1.2-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.	A hydrostatic test will be performed on the components required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the components identified in Table 2.1.2-1 as ASME Code Section III conform with the requirements of the ASME Code Section III.
4.b) The piping identified in Table 2.1.2-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.	A hydrostatic test will be performed on the piping required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the piping identified in Table 2.1.2-2 as ASME Code Section III conform with the requirements of the ASME Code Section III.

Table 2.1.2-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5.a) The seismic Category I equipment identified in Table 2.1.2-1 can withstand seismic design basis loads without loss of safety function.	i) Inspection will be performed to verify that the seismic Category I equipment and valves identified in Table 2.1.2-1 are located on the Nuclear Island.	i) The seismic Category I equipment identified in Table 2.1.2-1 is located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis loads without loss of safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) A report exists and concludes that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.
5.b) Each of the lines identified in Table 2.1.2-2 for which functional capability is required is designed to withstand combined normal and seismic design basis loads without a loss of its functional capability.	Inspection will be performed for the existence of a report verifying that the as-built piping meets the requirements for functional capability.	A report exists and concludes that each of the as-built lines identified in Table 2.1.2-2 for which functional capability is required meets the requirements for functional capability.
6. Each of the as-built lines identified in Table 2.1.2-2 as designed for LBB meets the LBB criteria, or an evaluation is performed of the protection from the dynamic effects of a rupture of the line.	Inspection will be performed for the existence of an LBB evaluation report or an evaluation report on the protection from dynamic effects of a pipe break. Tier 1 Material, Section 3.3, Nuclear Island Buildings, contains the design descriptions and inspections, tests, analyses, and acceptance criteria for protection from the dynamic effects of pipe rupture.	An LBB evaluation report exists and concludes that the LBB acceptance criteria are met by the as-built RCS piping and piping materials, or a pipe break evaluation report exists and concludes that protection from the dynamic effects of a line break is provided.

Table 2.1.2-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7.a) The Class 1E equipment identified in Table 2.1.2-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.	i) Type tests, analyses, or a combination of type tests and analyses will be performed on Class 1E equipment located in a harsh environment.	i) A report exists and concludes that the Class 1E equipment identified in Table 2.1.2-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.
	ii) Inspection will be performed of the as-installed Class 1E equipment and the associated wiring, cables, and terminations located in a harsh environment.	ii) A report exists and concludes that the as-installed Class 1E equipment and the associated wiring, cables, and terminations identified in Table 2.1.2-1 as being qualified for a harsh environment are bounded by type tests, analyses, or a combination of type tests and analyses.
7.b) The Class 1E components identified in Table 2.1.2-1 are powered from their respective Class 1E division.	Testing will be performed on the RCS by providing a simulated test signal in each Class 1E division.	A simulated test signal exists at the Class 1E equipment identified in Table 2.1.2-1 when the assigned Class 1E division is provided the test signal.
7.c) Separation is provided between RCS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.	See Tier 1 Material, Table 3.3-6, item 7.d.	See Tier 1 Material, Table 3.3-6, item 7.d.
8.a) The pressurizer safety valves provide overpressure protection in accordance with Section III of the ASME Boiler and Pressure Vessel Code.	i) Inspections will be conducted to confirm that the value of the vendor code plate rating is greater than or equal to system relief requirements.	i) The sum of the rated capacities recorded on the valve ASME Code plates of the safety valves exceeds 1,500,000 lb/hr.
	ii) Testing and analysis in accordance with ASME Code Section III will be performed to determine set pressure.	ii) A report exists and concludes that the safety valves set pressure is 2485 psig $\pm$ 25 psi.
8.b) The RCPs have a rotating inertia to provide RCS flow coastdown on loss of power to the pumps.	A test will be performed to determine the pump flow coastdown curve.	The pump flow coastdown will provide RCS flows greater than or equal to the flow shown in Figure 2.1.2-2, “Flow Transient for Four Cold Legs in Operation, Four Pumps Coasting Down.”

Table 2.1.2-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
8.c) Each RCP flywheel assembly can withstand a design overspeed condition.	Shop testing of each RCP flywheel assembly will be performed at the vendor facility at overspeed conditions.	Each RCP flywheel assembly has passed an overspeed condition of no less than 125% of operating speed.
8.d) The RCS provides automatic depressurization during design basis events.	i) A low pressure flow test and associated analysis will be conducted to determine the total piping flow resistance of each ADS valve group connected to the pressurizer (i.e., ADS Stages 1-3) from the pressurizer through the outlet of the downstream ADS control valves. The reactor coolant system will be at cold conditions with the pressurizer full of water. The normal residual heat removal pumps will be used to provide injection flow into the RCS discharging through the ADS valves. Inspections and associated analysis of the piping flow paths from the discharge of the ADS valve groups connected to the pressurizer (i.e., ADS Stages 1-3) to the spargers will be conducted to verify the line routings are consistent with the line routings used for design flow resistance calculations.	i) The calculated ADS piping flow resistance from the pressurizer through the sparger with all valves of each ADS group open is $\leq$ 2.91E-6 ft/gpm^2.
	ii) Inspections and associated analysis of each fourth-stage ADS valve group (four valves and associated piping connected to each hot leg) will be conducted to verify the line routing is consistent with the line routing used for design flow resistance calculations.	ii) The calculated flow resistance for each group of fourth-stage ADS valves and piping with all valves open is: Loop 1: $\leq 1.70 \times 10^{-7}$ ft/gpm^2 Loop 2: $\leq 1.57 \times 10^{-7}$ ft/gpm^2

Table 2.1.2-4 (cont.) Inspections, Tests, Analyses, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
	iii) Inspections of each fourth-stage ADS valve will be conducted to determine the flow area through each valve.	iii) The flow area through each fourth-stage ADS valve is $\geq$ 67 in^2.
	iv) Type tests and analysis will be performed to determine the effective flow area through each stage 1,2,3 ADS valve.	iv) A report exists and concludes that the effective flow area through each stage 1 ADS valve $\geq$ 4.6 in^2 and each stage 2,3 ADS valve is $\geq$ 21 in^2.
	v) Inspections of the elevation of the ADS stage 4 valve discharge will be conducted.	v) The minimum elevation of the bottom inside surface of the outlet of these valves is greater than plant elevation 110 feet.
	vi) Inspections of the ADS stage 4 valve discharge will be conducted.	vi) The discharge of the ADS stage 4 valves is directed into the steam generator compartments.
	vii) Inspection of each ADS sparger will be conducted to determine the flow area through the sparger holes.	vii) The flow area through the holes in each ADS sparger is $\geq$ 274 in^2.
	viii) Inspection of the elevation of each ADS sparger will be conducted.	viii) The centerline of the connection of the sparger arms to the sparger hub is $\leq$ 11.5 feet below the IRWST overflow level.
8.e) The RCS provides emergency letdown during design basis events.	Inspections of the reactor vessel head vent valves and inlet and outlet piping will be conducted.	A report exists and concludes that the capacity of the reactor vessel head vent is sufficient to pass not less than 8.2 lbm/sec at 1250 psia in the RCS.

Table 2.1.2-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9.a) The RCS provides circulation of coolant to remove heat from the core.	Testing and analysis to measure RCS flow with four reactor coolant pumps operating at no-load RCS pressure and temperature conditions will be performed. Analyses will be performed to convert the measured pre-fuel load flow to post-fuel load flow with 10-percent steam generator tube plugging.	The calculated post-fuel load RCS flow rate is $\geq$ 301,670 gpm.
9.b) The RCS provides the means to control system pressure.	i) Inspections will be performed to verify the rated capacity of pressurizer heater backup groups A and B.	i) Pressurizer heater backup groups A and B each has a rated capacity of at least 168 kW.
	ii) Tests will be performed to verify that the pressurizer spray valves can open and close when operated from the MCR.	ii) Controls in the MCR operate to cause the pressurizer spray valves to open and close.
9.c) The pressurizer heaters trip after a signal is generated by the PMS.	Testing will be performed to confirm trip of the pressurizer heaters identified in Table 2.1.2-3.	The pressurizer heaters identified in Table 2.1.2-3 trip after a signal is generated by the PMS.
10. Safety-related displays identified in Table 2.1.2-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the safety-related displays in the MCR.	Safety-related displays identified in Table 2.1.2-1 can be retrieved in the MCR.
11.a) Controls exist in the MCR to cause the remotely operated valves identified in Table 2.1.2-1 to perform active functions.	i) Testing will be performed on the squib valves identified in Table 2.1.2-1 using controls in the MCR without stroking the valve.	i) Controls in the MCR operate to cause a signal at the squib valve electrical leads which is capable of actuating the squib valve.
	ii) Stroke testing will be performed on the other remotely operated valves listed in Table 2.1.2-1 using controls in the MCR.	ii) Controls in the MCR operate to cause the remotely operated valves (other than squib valves) to perform active functions.

Table 2.1.2-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
11.b) The valves identified in Table 2.1.2-1 as having PMS control perform an active safety function after receiving a signal from the PMS.	i) Testing will be performed on the squib valves identified in Table 2.1.2-1 using real or simulated signals into the PMS without stroking the valve.	i) The squib valves receive a signal at the valve electrical leads that is capable of actuating the squib valve.
	ii) Testing will be performed on the other remotely operated valves identified in Table 2.1.2-1 using real or simulated signals into the PMS.	ii) The other remotely operated valves identified in Table 2.1.2-1 as having PMS control perform the active function identified in the table after receiving a signal from PMS.
	iii) Testing will be performed to demonstrate that remotely operated RCS valves RCS-V001A/B, V002A/B, V003A/B, V011A/B, V012A/B, V013A/B open within the required response times.	iii) These valves open within the following times after receipt of an actuation signal: V001A/B ≤ 30 sec V002A/B, V003A/B ≤ 80 sec V011A/B ≤ 20 sec V012A/B, V013A/B ≤ 30 sec
11.c) The valves identified in Table 2.1.2-1 as having DAS control perform an active safety function after receiving a signal from DAS.	i) Testing will be performed on the squib valves identified in Table 2.1.2-1 using real or simulated signals into the DAS without stroking the valve.	i) The squib valves receive a signal at the valve electrical leads that is capable of actuating the squib valve.
	ii) Testing will be performed on the other remotely operated valves identified in Table 2.1.2-1 using real or simulated signals into the DAS.	ii) The other remotely operated valves identified in Table 2.1.2-1 as having DAS control perform the active function identified in the table after receiving a signal from DAS.

Table 2.1.2-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
12.a) The automatic depressurization valves identified in Table 2.1.2-1 perform an active safety-related function to change position as indicated in the table.	i) Tests or type tests of motor-operated valves will be performed that demonstrate the capability of the valve to operate under its design conditions.	i) A test report exists and concludes that each motor-operated valve changes position as indicated in Table 2.1.2-1 under design conditions.
	ii) Inspection will be performed for the existence of a report verifying that the as-installed motor-operated valves are bounded by the tests or type tests.	ii) A report exists and concludes that the as-installed motor-operated valves are bounded by the tests or type tests.
	iii) Tests of the as-installed motor-operated valves will be performed under pre-operational flow, differential pressure and temperature conditions.	iii) Each motor-operated valve changes position as indicated in Table 2.1.2-1 under pre-operational test conditions.
	iv) Tests or type tests of squib valves will be performed that demonstrate the capability of the valve to operate under its design conditions.	iv) A test report exists and concludes that each squib valve changes position as indicated in Table 2.1.2-1 under design conditions.
	v) Inspection will be performed for the existence of a report verifying that the as-installed squib valves are bounded by the tests or type tests.	v) A report exists and concludes that the as-installed squib valves are bounded by the tests or type tests.
	vi) See item 8.d.i in this table.	vi) See item 8.d.i in this table. The ADS stage 1-3 valve flow resistances are verified to be consistent with the ADS stage 1-3 path flow resistances.
	vii) See item 8.d.ii in this table.	vii) See item 8.d.ii in this table. The ADS stage 4 valve flow resistances are verified to be consistent with the ADS stage 4 path flow resistances.
	viii) See item 8.d.iii in this table.	viii) See item 8.d.iii in this table.
	ix) See item 8.d.iv in this table.	ix) See item 8.d.iv in this table.

Table 2.1.2-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
12.b) After loss of motive power, the remotely operated valves identified in Table 2.1.2-1 assume the indicated loss of motive power position.	Testing of the installed valves will be performed under the conditions of loss of motive power.	Upon loss of motive power, each remotely operated valve identified in Table 2.1.2-1 assumes the indicated loss of motive power position.
13.a) Controls exist in the MCR to trip the RCPs.	Testing will be performed on the RCPs using controls in the MCR.	Controls in the MCR operate to trip the RCPs.
13.b) The RCPs trip after receiving a signal from the PMS.	Testing will be performed using real or simulated signals into the PMS.	The RCPs trip after receiving a signal from the PMS.
13.c) The RCPs trip after receiving a signal from the DAS.	Testing will be performed using real or simulated signals into the DAS.	The RCPs trip after receiving a signal from the DAS.
14. Controls exist in the MCR to cause the components identified in Table 2.1.2-3 to perform the listed function.	Testing will be performed on the components in Table 2.1.2-3 using controls in the MCR.	Controls in the MCR operate to cause the components listed in Table 2.1.2-3 to perform the listed functions.
15. Displays of the parameters identified in Table 2.1.2-3 can be retrieved in the MCR.	Inspection will be performed for retrievability of the RCS parameters in the MCR.	The displays identified in Table 2.1.2-3 can be retrieved in the MCR.

Table 2.1.2-5		
Component Name	**Tag No.**	**Component Location**
Steam Generator 1	RCS-MB-01	Containment
Steam Generator 2	RCS-MB-02	Containment
Reactor Coolant Pump 1A	RCS-MP-01A	Containment
Reactor Coolant Pump 1B	RCS-MP-01B	Containment
Reactor Coolant Pump 2A	RCS-MP-02A	Containment
Reactor Coolant Pump 2B	RCS-MP-02B	Containment
Pressurizer	RCS-MV-02	Containment
ADS Sparger A	PXS-MW-01A	Containment
ADS Sparger B	PXS-MW-01B	Containment

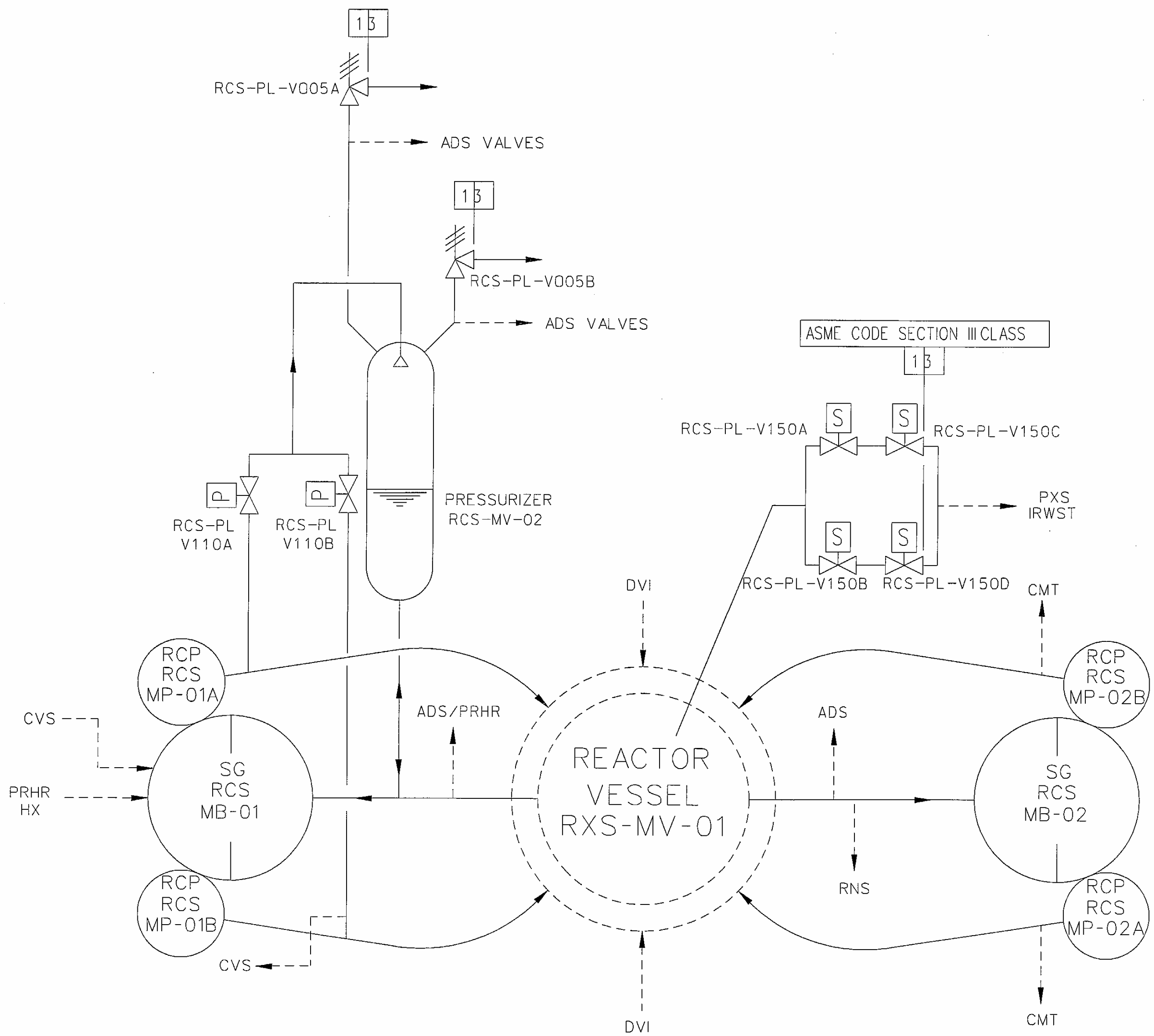


Figure 2.1.2-1 (Sheet 1 of 2)
Reactor Coolant System

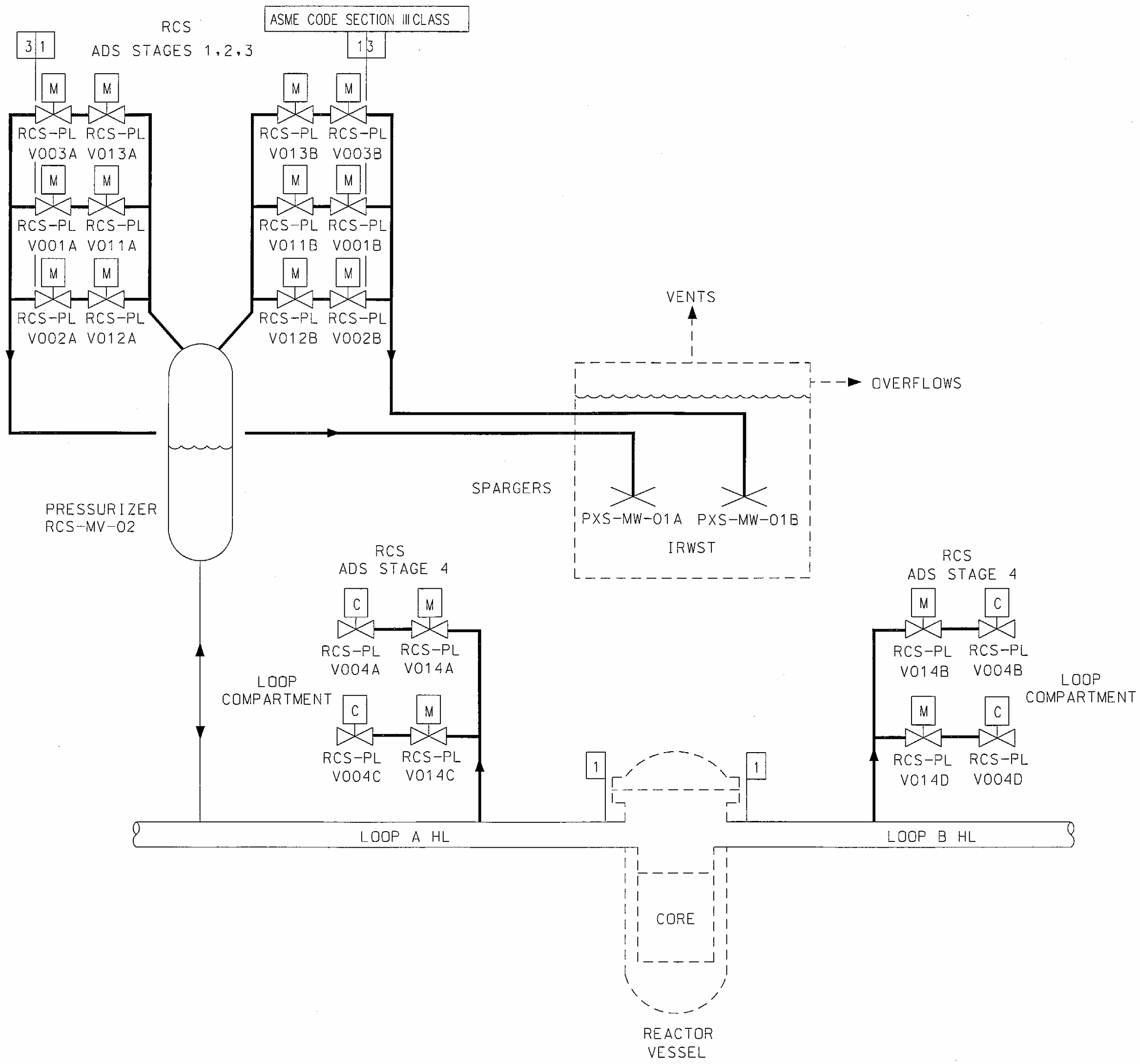


Figure 2.1.2-1 (Sheet 2 of 2)
Reactor Coolant System

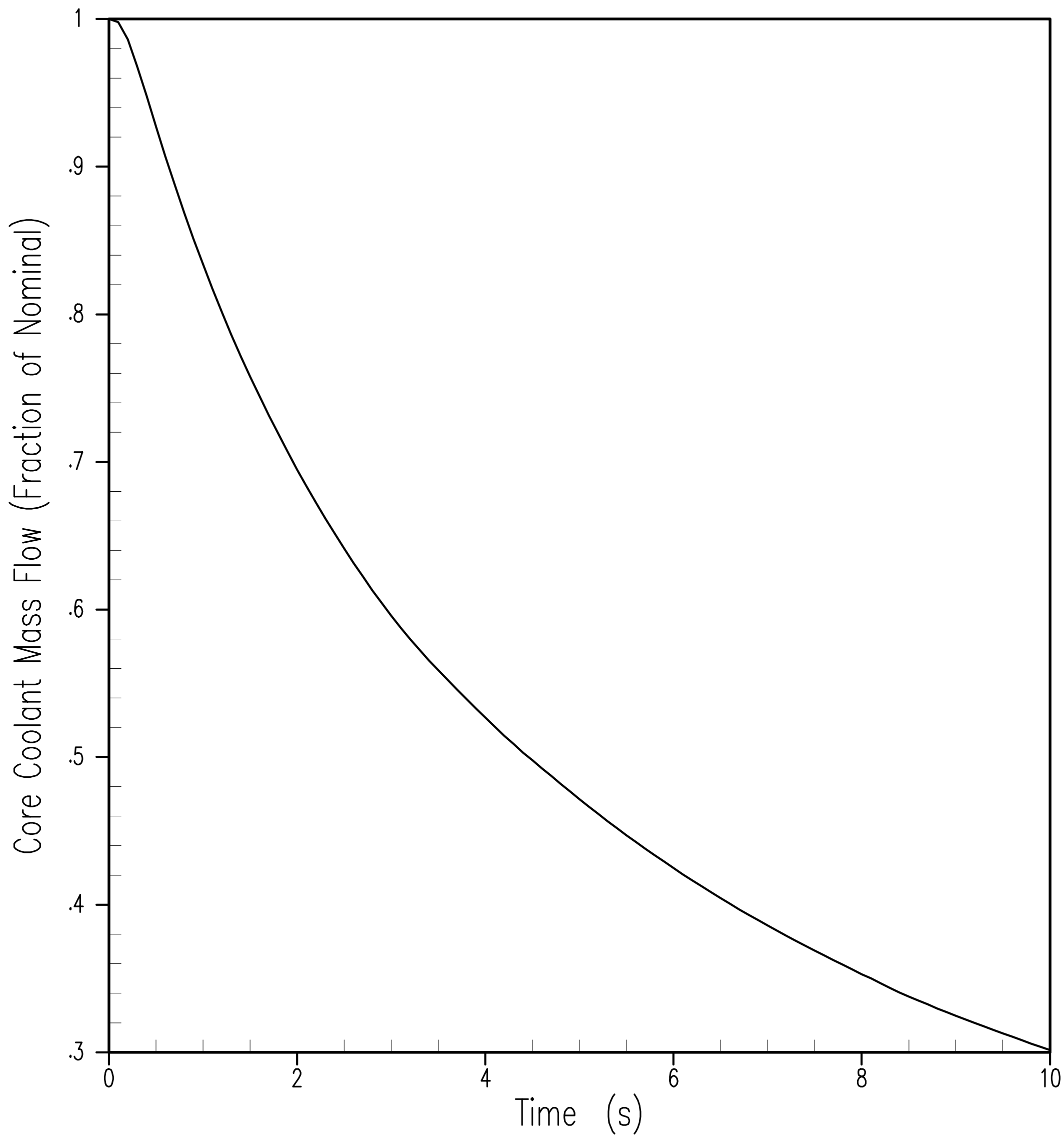


Figure 2.1.2-2
Flow Transient for Four Cold Legs
in Operation, Four Pumps Coasting Down

2.1.3 Reactor System

Design Description

The reactor system (RXS) generates heat by a controlled nuclear reaction and transfers the heat generated to the reactor coolant, provides a barrier that prevents the release of fission products to the atmosphere and a means to insert negative reactivity into the reactor core and to shutdown the reactor core.

The reactor core contains a matrix of fuel rods assembled into fuel assemblies using structural elements. Rod cluster control assemblies (RCCAs) are positioned and held within the fuel assemblies by control rod drive mechanisms (CRDMs). The CRDMs unlatch upon termination of electrical power to the CRDM thereby releasing the RCCAs. The fuel assemblies and RCCAs are designed in accordance with the principal design requirements.

The RXS is operated during normal modes of plant operation, including startup, power operation, cooldown, shutdown and refueling.

The component locations of the RXS are as shown in Table 2.1.3-3.

1. The functional arrangement of the RXS is as described in the Design Description of this Section 2.1.3.

2. a) The reactor upper internals rod guide arrangement is as shown in Figure 2.1.3-1.

   b) The rod cluster control and drive rod arrangement is as shown in Figure 2.1.3-2.

   c) The reactor vessel arrangement is as shown in Figure 2.1.3-3.

3. The components identified in Table 2.1.3-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.

4. Pressure boundary welds in components identified in Table 2.1.3-1 as ASME Code Section III meet ASME Code Section III requirements.

5. The pressure boundary components (reactor vessel [RV], control rod drive mechanisms [CRDMs], incore instrument guide tubes) identified in Table 2.1.3-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.

6. The seismic Category I equipment identified in Table 2.1.3-1 can withstand seismic design basis loads without loss of safety function.

7. The reactor internals will withstand the effects of flow induced vibration.

8. The reactor vessel direct injection nozzle limits the blowdown of the reactor coolant system (RCS) following the break of a direct vessel injection line.

9. a) The Class 1E equipment identified in Table 2.1.3-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.

b) The Class 1E components identified in Table 2.1.3-1 are powered from their respective Class 1E division.

c) Separation is provided between RXS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.

10. The reactor lower internals assembly is equipped with holders for at least eight capsules for storing material surveillance specimens.

11. The reactor pressure vessel (RPV) beltline material has a Charpy upper-shelf energy of no less than 75 ft-lb.

12. Safety-related displays of the parameters identified in Table 2.1.3-1 can be retrieved in the main control room (MCR).

13. The fuel assemblies and rod control cluster assemblies intended for initial core load and listed in Table 2.1.3-1 have been designed and constructed in accordance with the principal design requirements.

14. A top-of-the-head visual inspection, including 360 degrees around each reactor vessel head penetration nozzle, can be performed.

Inspections, Tests, Analysis, and Acceptance Criteria

Table 2.1.3-2 specifies the inspections, tests, analysis, and associated acceptance criteria for the RXS.

Table 2.1.3-1					
Equipment Name	**Tag No.**	**ASME Code Section III Classification**	**Seismic Cat. I**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**
RV	RXS-MV-01	Yes	Yes	-	-
Reactor Upper Internals Assembly	RXS-MI-01	Yes	Yes	-	-
Reactor Lower Internals Assembly	RXS-MI-02	Yes	Yes	-	-
Fuel Assemblies (157 locations)	RXS-FA-A07/A08/A09/B05/B06/B07/B08/ B09/B10/B11/C04/C05/C06/C07/C08/C09/C10/ C11/C12/D03/D04/D05/D06/D07/D08/D09/ D10/D11/D12/D13/E02/E03/E04/E05/E06/E07/ E08/E09/E10/E11/E12/E13/E14/F02/F03/F04/ F05/F06/F07/F08/F09/F10/F11/F12/F13/F14/ G01/G02/G03/G04/G05/G06/G07/G08/G09/ G10/G11/G12/G13/G14/G15/H01/H02/H03/ H04/H05/H06/H07/H08/H09/H10/H11/H12/ H13/H14/H15/J01/J02/J03/J04/J05/J06/J07/J08/ J09/J10/J11/J12/J13/J14/J15/K02/K03/K04/ K05/K06/K07/K08/K09/K10/K11/K12/K13/ K14/L02/L03/L04/L05/L06/L07/L08/L09/L10/ L11/L12/L13/L14/M03/M04/M05/M06/M07/ M08/M09/M10/M11/M12/M13/N04/N05/N06/ N07/N08/N09/N10/N11/N12/P05/P06/P07/P08/ P09/P10/P11/ R07/R08/R09	No[1]	Yes	-	-

Note: Dash (-) indicates not applicable.

1. Fuel assemblies are designed using ASME Section III as a general guide.

Table 2.1.3-1 (cont.)					
Equipment Name	**Tag No.**	**ASME Code Section III Classification**	**Seismic Cat. I**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**
Rod Cluster Control Assemblies (RCCAs) (minimum 53 locations)	RXS-FR-B06/B10/C05/C07/C09/C11/D06/ D08/D10/E03/E05/E07/E09/E11/E13/F02/F04/ F12/F14/G03/G05/G07/G09/G11/G13/H04/ H08/H12/J03/J05/J07/J09/J11/J13/K02/K04/ K12/K14/L03/L05/L07/L09/L11/L13/M06/ M08/M10/N05/N07/N09/N11/P06/P10	No(1)	Yes	-	-
Gray Rod Control Assemblies (GRCAs) (16 locations)	RXS-FG-B08/D04/D12/F06/F08/F10/H02/H06/ H10/H14/K06/K08/K10/M04/M12/P08	No(1)	Yes	-	-
Control Rod Drive Mechanisms (CRDMs) (69 Locations)	RXS-MV-11B06/11B08/11B10/11C05/11C07/ 11C09/11C11/11D04/11D06/11D08/11D10/ 11D12/11E03/11E05/11E07/11E09/11E11/ 11E13/11F02/11F04/11F06/11F08/11F10/ 11F12/11F14/11G03/11G05/11G07/11G09/ 11G11/11G13/11H02/11H04/11H06/11H08/ 11H10/11H12/11H14/11J03/11J05/11J07/ 11J09/11J11/11J13/11K02/11K04/11K06/ 11K08/11K10/11K12/11K14/11L03/11L05/ 11L07/11L09/11L11/11L13/11M04/11M06/ 11M08/11M10/11M12/11N05/11N07/11N09/ 11N11/11P06/11P08/11P10	Yes	Yes	No/No	No
Incore Instrument Guide Tubes (42 Core Locations)	IIS-JT-G01 through G42	Yes	-	-	-

Note: Dash (-) indicates not applicable.

1. Fuel assemblies are designed using ASME Section III as a general guide.

Table 2.1.3-1 (cont.)					
Equipment Name	**Tag No.**	**ASME Code Section III Classification**	**Seismic Cat. I**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**
Source Range Detectors (4)	RXS-JE-NE001A/NE001B/NE001C/NE001D	-	Yes	Yes/Yes	No
Intermediate Range Detectors (4)	RXS-JE-NE002A/NE002B/NE002C/NE002D	-	Yes	Yes/Yes	Yes
Power Range Detectors – Lower (4)	RXS-JE-NE003A/NE003B/NE003C/NE003D	-	Yes	Yes/Yes	No
Power Range Detectors – Upper (4)	RXS-JE-NE004A/NE004B/NE004C/NE004D	-	Yes	Yes/Yes	No

Note: Dash (-) indicates not applicable.

Table 2.1.3-2
Inspections, Tests, Analysis, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analysis	Acceptance Criteria
1. The functional arrangement of the RXS is as described in the Design Description of this Section 2.1.3.	Inspection of the as-built system will be performed.	The as-built RXS conforms with the functional arrangement as described in the Design Description of this Section 2.1.3.
2.a) The reactor upper internals rod guide arrangement is as shown in Figure 2.3.1-1.	Inspection of the as-built system will be performed.	The as-built RXS will accommodate the fuel assembly and control rod drive mechanism pattern shown in Figure 2.3.1-1.
2.b) The control assemblies (rod cluster and grey rod) and drive rod arrangement is as shown in Figure 2.1.3-2.	Inspection of the as-built system will be performed.	The as-built RXS will accommodate the control assemblies (rod cluster and grey rod) and drive rod arrangement shown in Figure 2.1.3-2.
2.c) The reactor vessel arrangement is as shown in Figure 2.1.3-3.	Inspection of the as-built system will be performed.	The as-built RXS will accommodate the reactor vessel arrangement shown in Figure 2.1.3-3.
3. The components identified in Table 2.1.3-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built components as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built components identified in Table 2.1.3-1 as ASME Code Section III.
4. Pressure boundary welds in components identified in Table 2.1.3-1 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
5. The pressure boundary components (RV, CRDMs, incore instrument guide tubes) retain their pressure boundary integrity at their design pressure.	A hydrostatic test will be performed on the components of the RXS required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the pressure boundary components (RV, CRDM's, incore instrument guide tubes) conform with the requirements of the ASME Code Section III.

Table 2.1.3-2 (cont.)
Inspections, Tests, Analysis, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analysis	Acceptance Criteria
6. The seismic Category I equipment identified in Table 2.1.3-1 can withstand seismic design basis loads without loss of safety function.	i) Inspection will be performed to verify that the seismic Category I equipment identified in Table 2.1.3-1 is located on the Nuclear Island.	i) The seismic Category I equipment identified in Table 2.1.3-1 is located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis loads without loss of safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) A report exists and concludes that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.
7. The reactor internals will withstand the effects of flow induced vibration.	i) A vibration type test will be conducted on the (first unit) reactor internals representative of AP1000.	i) A report exists and concludes that the (first unit) reactor internals have no observable damage or loose parts as a result of the vibration type test.
	ii) A pre-test inspection, a flow test and a post-test inspection will be conducted on the as-built reactor internals.	ii) The as-built reactor internals have no observable damage or loose parts.
8. The reactor vessel direct vessel injection nozzle limits the blowdown of the RCS following the break of a direct vessel injection line.	An inspection will be conducted to verify the flow area of the flow limiting venturi within each direct vessel injection nozzle.	The throat area of the direct vessel injection line nozzle flow limiting venturi is less than or equal to 12.57 in^2.

Table 2.1.3-2 (cont.)
Inspections, Tests, Analysis, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analysis	Acceptance Criteria
9.a) The Class 1E equipment identified in Table 2.1.3-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.	i) Type tests, analysis, or a combination of type tests and analysis will be performed on Class 1E equipment located in a harsh environment.	i) A report exists and concludes that the Class 1E equipment identified in Table 2.1.3-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.
	ii) Inspection will be performed of the as-installed Class 1E equipment and the associated wiring, cables, and terminations located in a harsh environment.	ii) A report exists and concludes that the as-installed Class 1E equipment and the associated wiring, cables, and terminations identified in Table 2.1.3-1 as being qualified for a harsh environment are bounded by type tests, analyses, or a combination of type tests and analyses.
9.b) The Class 1E components identified in Table 2.1.3-1 are powered from their respective Class 1E division.	Testing will be performed by providing simulated test signals in each Class 1E division.	A simulated test signal exists for Class 1E equipment identified in Table 2.1.3-1 when the assigned Class 1E division is provided the test signal.
9.c) Separation is provided between RXS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.	See Tier 1 Material, Table 3.3-6, item 7.d.	See Tier 1 Material, Table 3.3-6, item 7.d.
10. The reactor lower internals assembly is equipped with holders for at least eight capsules for storing material surveillance specimens.	Inspection of the reactor lower internals assembly for the presence of capsules will be performed.	At least eight capsules are in the reactor lower internals assembly.
11. The RPV beltline material has a Charpy upper-shelf energy of no less than 75 ft-lb.	Testing of the Charpy V-Notch specimen of the RPV beltline material will be performed.	A report exists and concludes that the initial RPV beltline Charpy upper-shelf energy is no less than 75 ft-lb.
12. Safety-related displays of the parameters identified in Table 2.1.3-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the safety-related displays in the MCR.	Safety-related displays identified in Table 2.1.3-1 can be retrieved in the MCR.

Table 2.1.3-2 (cont.) Inspections, Tests, Analysis, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analysis**	**Acceptance Criteria**
13. The fuel assemblies and rod control cluster assemblies intended for initial core load and listed in Table 2.1.3-1 have been designed and constructed in accordance with the established design requirements.	An analysis is performed of the reactor core design.	A report exists and concludes that the fuel assemblies and rod cluster control rod assemblies intended for the initial core load and listed in Table 2.1.3-1 have been designed and constructed in accordance with the principal design requirements.
14. A top-of-the-head visual inspection, including 360 degrees around each reactor vessel head penetration nozzle, can be performed.	A preservice visual examination of the reactor vessel head top surface and penetration nozzles will be performed.	A report exists that documents the results of the top-of-the-head visual inspection, including 360 degrees around each reactor vessel head penetration nozzle.

Table 2.1.3-3		
Component Name	**Tag No.**	**Component Location**
RV	RXS-MV-01	Containment
Reactor Upper Internals Assembly	RXS-MI-01	Containment
Reactor Lower Internals Assembly	RXS-MI-02	Containment
Fuel Assemblies (157 locations)	RXS-FA-A07/A08/A09/B05/B06/B07/B08/B09/B10/B11/C04/C05/C06/C07/C08/C09/C10/C11/C12/D03/D04/D05/D06/D07/D08/D09/D10/D11/D12/D13/E02/E03/E04/E05/E06/E07/E08/E09/E10/E11/E12/E13/E14/F02/F03/F04/F05/F06/F07/F08/F09/F10/F11/F12/F13/F14/G01/G02/G03/G04/G05/G06/G07/G08/G09/G10/G11/G12/G13/G14/G15/H01/H02/H03/H04/H05/H06/H07/H08/H09/H10/H11/H12/H13/H14/H15/J01/J02/J03/J04/J05/J06/J07/J08/J09/J10/J11/J12/J13/J14/J15/K02/K03/K04/K05/K06/K07/K08/K09/K10/K11/K12/K13/K14/L02/L03/L04/L05/L06/L07/L08/L09/L10/L11/L12/L13/L14/M03/M04/M05/M06/M07/M08/M09/M10/M11/M12/M13/N04/N05/N06/N07/N08/N09/N10/N11/N12/P05/P06/P07/P08/P09/P10/P11/R07/R08/R09	Containment
Rod Cluster Control Assemblies (RCCAs) (minimum 53 locations)	RXS-FR-B06/B10/C05/C07/C09/C11/D06/D08/D10/E03/E05/E07/E09/E11/E13/F02/F04/F12/F14/G03/G05/G07/G09/G11/G13/H04/H08/H12/J03/J05/J07/J09/J11/J13/K02/K04/K12/K14/L03/L05/L07/L09/L11/L13/M06/M08/M10/N05/N07/N09/N11/P06/P10	Containment
Gray Rod Control Assemblies (GRCAs) (16 locations)	RXS-FG-B08/D04/D12/F06/F08/F10/H02/H06/H10/H14/K06/K08/K10/M04/M12/P08	Containment

Table 2.1.3-3 (cont.)		
Component Name	**Tag No.**	**Component Location**
Control Rod Drive Mechanisms (CRDMs) (69 Locations)	RXS-MV-11B06/11B08/ 11B10/11C05/11C07/11C09/ 11C11/11D04/11D06/11D08/ 11D10/11D12/11E03/11E05/ 11E07/11E09/11E11/11E13/ 11F02/11F04/11F06/11F08/ 11F10/11F12/11F14/11G03/ 11G05/11G07/11G09/11G11/ 11G13/11H02/11H04/11H06/ 11H08/11H10/11H12/11H14/ 11J03/11J05/11J07/11J09/11J11/ 11J13/11K02/11K04/11K06/ 11K08/11K10/11K12/11K14/ 11L03/11L05/11L07/11L09/ 11L11/11L13/11M04/11M06/ 11M08/11M10/11M12/11N05/ 11N07/11N09/11N11/11P06/ 11P08/11P10	Containment
Incore Instrument Guide Tubes (42 Core Locations)	IIS-JT-G01 through G42	Containment
Source Range Detectors (4)	RXS-JE-NE001A/NE001B/ NE001C/NE001D	Containment
Intermediate Range Detectors (4)	RXS-JE-NE002A/NE002B/ NE002C/NE002D	Containment
Power Range Detectors – Lower (4)	RXS-JE-NE003A/NE003B/ NE003C/NE003D	Containment
Power Range Detectors – Upper (4)	RXS-JE-NE004A/NE004B/ NE004C/NE004D	Containment

Table 2.1.3-4
Key Dimensions and Acceptable Variations of the Reactor Vessel and Internals
(Figure 2.1.3.2 and Figure 2.1.3-3)

Description	Dimension or Elevation (inches)	Nominal Value (inches)	Acceptable Variation (inches)
RV inside diameter at beltline (inside cladding)	A	159.0	+1.0/-1.0
RV wall thickness at beltline (without cladding)	B	8.4	+1.0/-0.12
RV wall thickness at bottom head (without cladding)	C	6.0	+1.0/-0.12
RV inlet nozzle inside diameter at safe end	D	22.0	+0.35/-0.10
RV outlet nozzle inside diameter at safe end	E	31.0	+0.35/-0.10
Elevation from RV mating surface to centerline of inlet nozzle	F	62.5	+0.25/-0.25
Elevation from RV mating surface to centerline of outlet nozzle	G	80.0	+0.25/-0.25
Elevation from RV mating surface to centerline of direct vessel injection nozzle	H	100.0	+0.25/-0.25
Elevation from RV mating surface to inside of RV bottom head (inside cladding)	I	397.59	+1.0/-0.50
Elevation from RV mating surface to top of lower core support plate	J	327.3	+0.50/-0.50
Separation distance between bottom of upper core plate and top of lower core support with RV head in place	K	189.8	+0.20/0.20

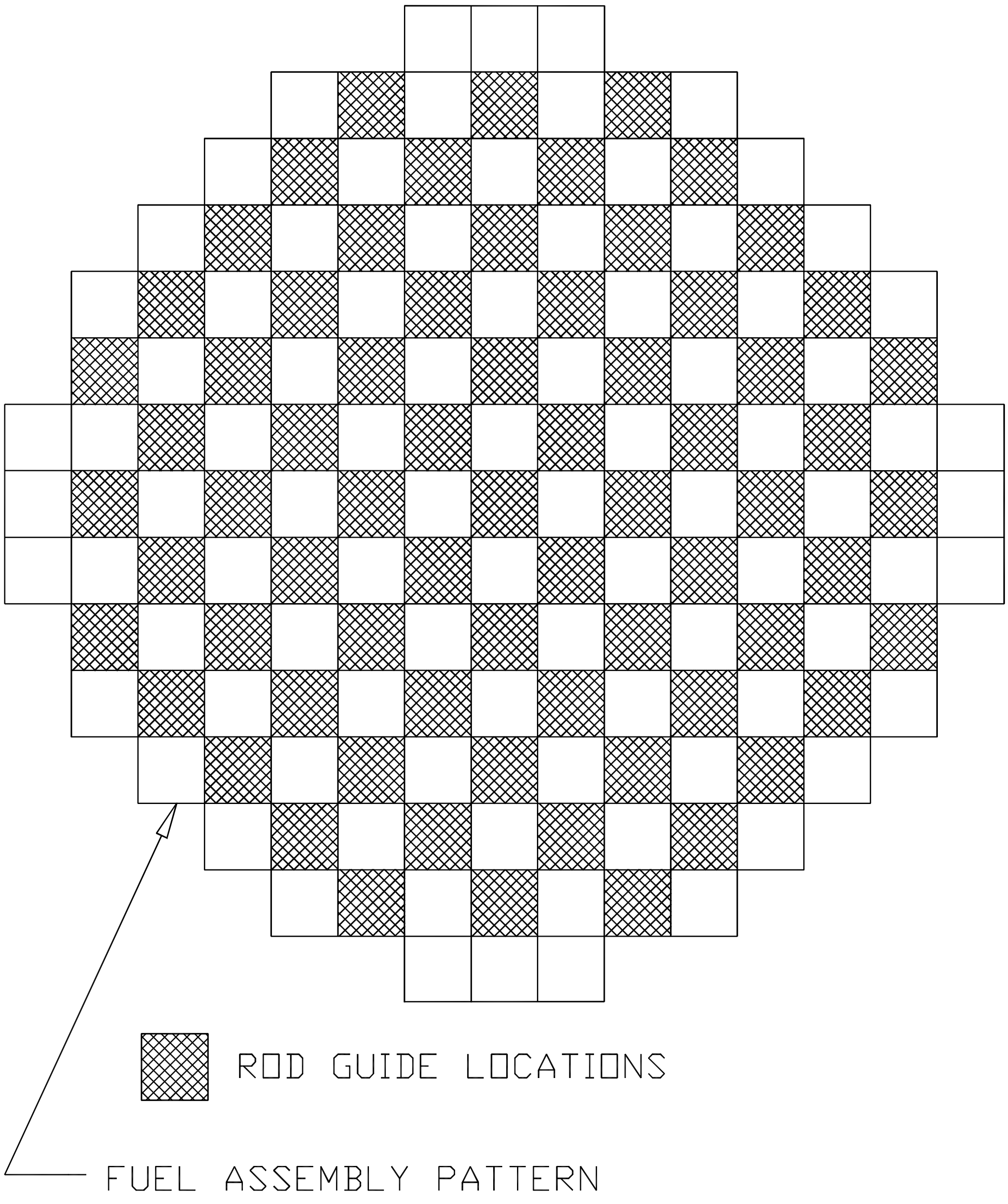


Figure 2.1.3-1
Reactor Upper Internals Rod Guide Arrangement

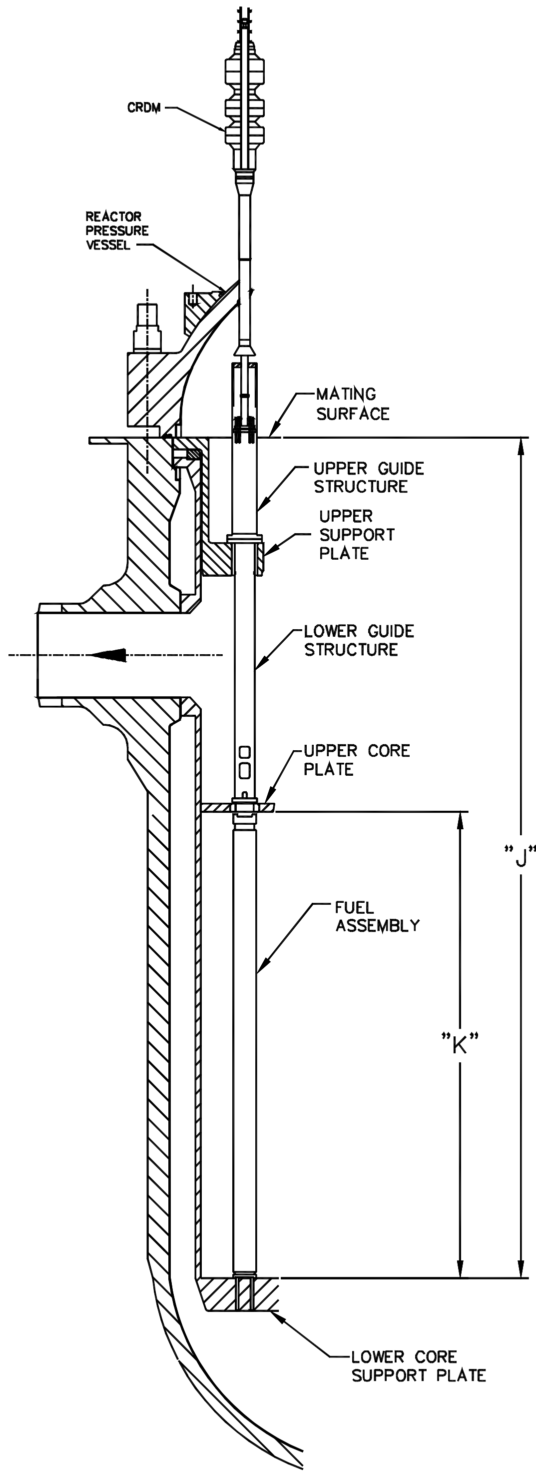


Figure 2.1.3-2
Rod Cluster Control and Drive Rod Arrangement

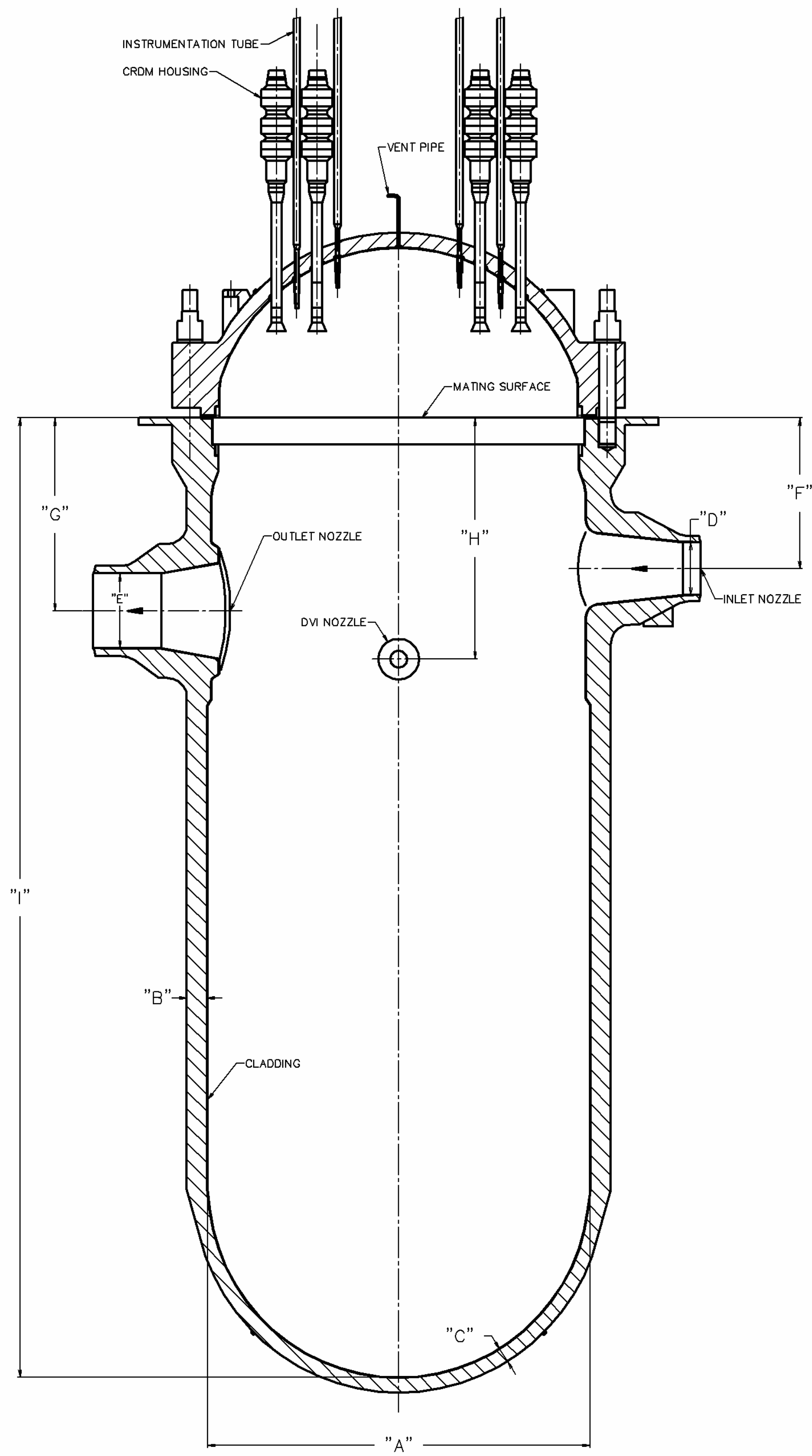


Figure 2.1.3-3
Reactor Vessel Arrangement

2.2.1 Containment System

Design Description

The containment system (CNS) is the collection of boundaries that separates the containment atmosphere from the outside environment during design basis accidents.

The CNS is as shown in Figure 2.2.1-1 and the component locations of the CNS are as shown in Table 2.2.1-4.

1. The functional arrangement of the CNS and associated systems is as described in the Design Description of this Section 2.2.1.

2. a) The components identified in Table 2.2.1-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.

   b) The piping identified in Table 2.2.1-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.

3. a) Pressure boundary welds in components identified in Table 2.2.1-1 as ASME Code Section III meet ASME Code Section III requirements.

   b) Pressure boundary welds in piping identified in Table 2.2.1-2 as ASME Code Section III meet ASME Code Section III requirements.

4. a) The components identified in Table 2.2.1-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.

   b) The piping identified in Table 2.2.1-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.

5. The seismic Category I equipment identified in Table 2.2.1-1 can withstand seismic design basis loads without loss of structural integrity and safety function.

6. a) The Class 1E equipment identified in Table 2.2.1-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.

   b) The Class 1E components identified in Table 2.2.1-1 are powered from their respective Class 1E division.

   c) Separation is provided between CNS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.

7. The CNS provides the safety-related function of containment isolation for containment boundary integrity and provides a barrier against the release of fission products to the atmosphere.

8. Containment electrical penetration assemblies are protected against currents that are greater than the continuous ratings.

9. Safety-related displays identified in Table 2.2.1-1 can be retrieved in the main control room (MCR).

10. a) Controls exist in the MCR to cause those remotely operated valves identified in Table 2.2.1-1 to perform active functions.

    b) The valves identified in Table 2.2.1-1 as having protection and safety monitoring system (PMS) control perform an active function after receiving a signal from the PMS.

    c) The valves identified in Table 2.2.1-1 as having diverse actuation system (DAS) control perform an active function after receiving a signal from the DAS.

11. a) The motor-operated and check valves identified in Table 2.2.1-1 perform an active safety-related function to change position as indicated in the table.

    b) After loss of motive power, the remotely operated valves identified in Table 2.2.1-1 assume the indicated loss of motive power position.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.2.1-3 specifies the inspections, tests, analyses, and associated acceptance criteria for the CNS.

Table 2.2.1-1									
Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS/DAS	Active Function	Loss of Motive Power Position
Service Air Supply Outside Containment Isolation Valve	CAS-PL-V204	Yes	Yes	No	-/-	No	-/-	None	-
Service Air Supply Inside Containment Isolation Check Valve	CAS-PL-V205	Yes	Yes	No	-/-	No	-/-	None	-
Instrument Air Supply Outside Containment Isolation Valve	CAS-PL-V014	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Closed	Closed
Instrument Air Supply Inside Containment Isolation Check Valve	CAS-PL-V015	Yes	Yes	No	-/-	-	-/-	Transfer Closed	-
Component Cooling Water System (CCS) Containment Isolation Motor-operated Valve (MOV) – Inlet Line Outside Reactor Containment (ORC)	CCS-PL-V200	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Closed	As Is
CCS Containment Isolation Check Valve – Inlet Line Inside Reactor Containment (IRC)	CCS-PL-V201	Yes	Yes	No	-/-	No	-/-	Transfer Closed	-

Note: Dash (-) indicates not applicable.

Table 2.2.1-1 (cont.)

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS/DAS	Active Function	Loss of Motive Power Position
CCS Containment Isolation MOV – Outlet Line IRC	CCS-PL-V207	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/No	Transfer Closed	As Is
CCS Containment Isolation MOV – Outlet Line ORC	CCS-PL-V208	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Closed	As Is
Demineralized Water Supply Containment Isolation Valve ORC	DWS-PL-V244	Yes	Yes	No	-/-	No	-/-	None	-
Demineralized Water Supply Containment Isolation Check Valve IRC	DWS-PL-V245	Yes	Yes	No	-/-	No	-/-	None	-
Fuel Transfer Tube	FHS-FT-001	Yes	Yes	-	-/-	-	-/-	-	-
Fire Water Containment Supply Isolation Valve – Outside	FPS-PL-V050	Yes	Yes	No	-/-	No	-/-	None	-
Fire Water Containment Isolation Supply Check Valve – Inside	FPS-PL-V052	Yes	Yes	No	-/-	No	-/-	None	-
Spent Fuel Pool Cooling System (SFS) Discharge Line Containment Isolation Check Valve – IRC	SFS-PL-V037	Yes	Yes	No	-/-	No	-/-	Transfer Closed	-
SFS Discharge Line Containment Isolation MOV – ORC	SFS-PL-V038	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Closed	As Is

Note: Dash (-) indicates not applicable.

Table 2.2.1-1 (cont.)

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS/DAS	Active Function	Loss of Motive Power Position
SFS Suction Line Containment Isolation MOV – IRC	SFS-PL-V034	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/No	Transfer Closed	As Is
SFS Suction Line Containment Isolation MOV – ORC	SFS-PL-V035	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Closed	As Is
Containment Purge Inlet Containment Isolation Valve – ORC	VFS-PL-V003	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/Yes	Transfer Closed	Closed
Containment Purge Inlet Containment Isolation Valve – IRC	VFS-PL-V004	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/Yes	Transfer Closed	Closed
Integrated Leak Rate Testing Vent Discharge Containment Isolation Valve – ORC	VFS-PL-V008	Yes	Yes	No	-/-	No	-/-	None	-
Containment Purge Discharge Containment Isolation Valve – IRC	VFS-PL-V009	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/Yes	Transfer Closed	Closed
Containment Purge Discharge Containment Isolation Valve – ORC	VFS-PL-V010	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/Yes	Transfer Closed	Closed
Fan Coolers Return Containment Isolation Valve – IRC	VWS-PL-V082	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/No	Transfer Closed	Closed
Fan Coolers Return Containment Isolation Valve – ORC	VWS-PL-V086	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Closed	Closed

Note: Dash (-) indicates not applicable.

Table 2.2.1-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS/DAS**	**Active Function**	**Loss of Motive Power Position**
Fan Coolers Supply Containment Isolation Valve – ORC	VWS-PL-V058	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Closed	Closed
Fan Coolers Supply Containment Isolation Check Valve – IRC	VWS-PL-V062	Yes	Yes	No	-/-	No	-/-	Transfer Closed	-
Reactor Coolant Drain Tank (RCDT) Gas Outlet Containment Isolation Valve – IRC	WLS-PL-V067	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/No	Transfer Closed	Closed
RCDT Gas Outlet Containment Isolation Valve – ORC	WLS-PL-V068	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Closed	Closed
Sump Discharge Containment Isolation Valve – IRC	WLS-PL-V055	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/Yes	Transfer Closed	Closed
Sump Discharge Containment Isolation Valve – ORC	WLS-PL-V057	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/Yes	Transfer Closed	Closed
Spare Penetration	CNS-PY-C01	Yes	Yes	-	-/-	-	-/-	-	-
Spare Penetration	CNS-PY-C02	Yes	Yes	-	-/-	-	-/-	-	-
Spare Penetration	CNS-PY-C03	Yes	Yes	-	-/-	-	-/-	-	-
Main Equipment Hatch	CNS-MY-Y01	Yes	Yes	-	-/-	-	-/-	-	-

Note: Dash (-) indicates not applicable.

Table 2.2.1-1 (cont.)

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS/ DAS	Active Function	Loss of Motive Power Position
Maintenance Hatch	CNS-MY-Y02	Yes	Yes	-	-/-	-	-/-	-	-
Personnel Hatch	CNS-MY-Y03	Yes	Yes	-	-/-	-	-/-	-	-
Personnel Hatch	CNS-MY-Y04	Yes	Yes	-	-/-	-	-/-	-	-
Containment Vessel	CNS-MV-01	Yes	Yes	-	-/-	-	-/-	-	-
Electrical Penetration P01	ECS-EY-P01X	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P02	ECS-EY-P02X	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P06	ECS-EY-P06Y	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P09	ECS-EY-P09W	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P10	ECS-EY-P10W	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P11	ECS-EY-P11Z	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P12	ECS-EY-P12Y	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P13	ECS-EY-P13Y	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P14	ECS-EY-P14Z	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P15	ECS-EY-P15Y	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P16	ECS-EY-P16Y	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P18	ECS-EY-P18X	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P21	ECS-EY-P21Z	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P22	ECS-EY-P22X	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P23	ECS-EY-P23X	Yes	Yes	-	Yes/Yes	-	-/-	-	-

Note: Dash (-) indicates not applicable.

Table 2.2.1-1 (cont.)

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS/ DAS	Active Function	Loss of Motive Power Position
Electrical Penetration P24	ECS-EY-P24	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P25	ECS-EY-P25W	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P26	ECS-EY-P26W	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P27	ECS-EY-P27Z	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P28	ECS-EY-P28Y	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P29	ECS-EY-P29Y	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P30	ECS-EY-P30Z	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P31	ECS-EY-P31Y	Yes	Yes	-	Yes/Yes	-	-/-	-	-
Electrical Penetration P32	ECS-EY-P32Y	Yes	Yes	-	Yes/Yes	-	-/-	-	-

Note: Dash (-) indicates not applicable.

Table 2.2.1-2		
Line Name	**Line Number**	**ASME Code Section III**
Instrument Air In	CAS-PL-L014, L015	Yes
Service Air In	CAS-PL-L204, L210	Yes
Component Cooling Water Supply to Containment	CCS-PL-L201	Yes
Component Cooling Water Outlet from Containment	CCS-PL-L207	Yes
Demineralized Water In	DWS-PL-L245, L230	Yes
Fire Protection Supply to Containment	FPS-PL-L107	Yes
Spent Fuel Pool Cooling Discharge	SFS-PL-L017	Yes
Spent Fuel Pool Cooling Suction from Containment	SFS-PL-L038	Yes
Containment Purge Inlet to Containment	VFS-PL-L104, L105, L106	Yes
Containment Purge Discharge from Containment	VFS-PL-L203, L204, L205	Yes
Fan Cooler Supply Line to Containment	VWS-PL-L032	Yes
Fan Cooler Return Line from Containment	VWS-PL-L055	Yes
RCDT Gas Out	WLS-PL-L022	Yes
Waste Sump Out	WLS-PL-L073	Yes

Table 2.2.1-3
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the CNS and associated systems is as described in the Design Description of this Section 2.2.1.	Inspection of the as-built system will be performed.	The as-built CNS conforms with the functional arrangement as described in the Design Description of this Section 2.2.1.
2.a) The components identified in Table 2.2.1-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built components as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built components identified in Table 2.2.1-1 as ASME Code Section III.
2.b) The piping identified in Table 2.2.1-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built piping as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built piping identified in Table 2.2.1-2 as ASME Code Section III.
3.a) Pressure boundary welds in components identified in Table 2.2.1-1 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
3.b) Pressure boundary welds in piping identified in Table 2.2.1-2 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.

Table 2.2.1-3 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4.a) The components identified in Table 2.2.1-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.	i) A hydrostatic or pressure test will be performed on the components required by the ASME Code Section III to be tested.	iii) A report exists and concludes that the results of the pressure test of the components identified in Table 2.2.1-1 as ASME Code Section III conform with the requirements of the ASME Code Section III.
	ii) Impact testing will be performed on the containment and pressure-retaining penetration materials in accordance with the ASME Code Section III, Subsection NE, to confirm the fracture toughness of the materials.	ii) A report exists and concludes that the containment and pressure-retaining penetration materials conform with fracture toughness requirements of the ASME Code Section III.
4.b) The piping identified in Table 2.2.1-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.	A hydrostatic or pressure test will be performed on the piping required by the ASME Code Section III to be pressure tested.	A report exists and concludes that the results of the pressure test of the piping identified in Table 2.2.1-2 as ASME Code Section III conform with the requirements of the ASME Code Section III.
5. The seismic Category I equipment identified in Table 2.2.1-1 can withstand seismic design basis loads without loss of structural integrity and safety function.	i) Inspection will be performed to verify that the seismic Category I equipment and valves identified in Table 2.2.1-1 are located on the Nuclear Island.	i) The seismic Category I equipment identified in Table 2.2.1-1 is located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis dynamic loads without loss of structural integrity and safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) The as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.

Table 2.2.1-3 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6.a) The Class 1E equipment identified in Table 2.2.1-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.	i) Type tests, analyses, or a combination of type tests and analyses will be performed on Class 1E equipment located in a harsh environment.	i) A report exists and concludes that the Class 1E equipment identified in Table 2.2.1-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.
	ii) Inspection will be performed of the as-installed Class 1E equipment and the associated wiring, cables, and terminations located in a harsh environment.	ii) A report exists and concludes that the as-installed Class 1E equipment and the associated wiring, cables, and terminations identified in Table 2.2.1-1 as being qualified for a harsh environment are bounded by type tests, analyses, or a combination of type tests and analyses.
6.b) The Class 1E components identified in Table 2.2.1-1 are powered from their respective Class 1E division.	Testing will be performed by providing a simulated test signal in each Class 1E division.	A simulated test signal exists at the Class 1E equipment identified in Table 2.2.1-1 when the assigned Class 1E division is provided the test signal.
6.c) Separation is provided between CNS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.	See Tier 1 Material, Table 3.3-6, item 7.d.	See Tier 1 Material, Table 3.3-6, item 7.d.
7. The CNS provides the safety-related function of containment isolation for containment boundary integrity and provides a barrier against the release of fission products to the atmosphere.	i) A containment integrated leak rate test will be performed.	i) The leakage rate from containment for the integrated leak rate test is less than L_a.
	ii) Testing will be performed to demonstrate that remotely operated containment isolation valves close within the required response times.	ii) The containment purge isolation valves (VFS-PL-V003, -V004, -V009, and -V010) close within 20 seconds, SGS valves SGS-PL-V040A/B and SGS-PL-V057A/B are covered in Tier 1 Material, subsection 2.2.4, Table 2.2.4-4 (item 11.b.ii) and all other containment isolation valves close within 60 seconds upon receipt of an actuation signal.

Table 2.2.1-3 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
8. Containment electrical penetration assemblies are protected against currents that are greater than the continuous ratings.	An analysis for the as-built containment electrical penetration assemblies will be performed to demonstrate (1) that the maximum current of the circuits does not exceed the continuous rating of the containment electrical penetration assembly, or (2) that the circuits have redundant protection devices in series and that the redundant current protection devices are coordinated with the containment electrical penetration assembly's rated short circuit thermal capacity data and prevent current from exceeding the continuous current rating of the containment electrical penetration assembly.	Analysis exists for the as-built containment electrical penetration assemblies and concludes that the penetrations are protected against currents which are greater than their continuous ratings.
9. Safety-related displays identified in Table 2.2.1-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the safety-related displays in the MCR.	Safety-related displays identified in Table 2.2.1-1 can be retrieved in the MCR.
10.a) Controls exist in the MCR to cause those remotely operated valves identified in Table 2.2.1-1 to perform active functions.	Stroke testing will be performed on remotely operated valves identified in Table 2.2.1-1 using the controls in the MCR.	Controls in the MCR operate to cause remotely operated valves identified in Table 2.2.1-1 to perform active safety functions.
10.b) The valves identified in Table 2.2.1-1 as having PMS control perform an active safety function after receiving a signal from the PMS.	Testing will be performed on remotely operated valves listed in Table 2.2.1-1 using real or simulated signals into the PMS.	The remotely operated valves identified in Table 2.2.1-1 as having PMS control perform the active function identified in the table after receiving a signal from PMS.
10.c) The valves identified in Table 2.2.1-1 as having DAS control perform an active safety function after receiving a signal from DAS.	Testing will be performed on remotely operated valves listed in Table 2.2.1-1 using real or simulated signals into the DAS.	The remotely operated valves identified in Table 2.2.1-1 as having DAS control perform the active function identified in the table after receiving a signal from DAS.

Table 2.2.1-3 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
11.a) The motor-operated and check valves identified in Table 2.2.1-1 perform an active safety-related function to change position as indicated in the table.	i) Tests or type tests of motor-operated valves will be performed to demonstrate the capability of each valve to operate under design conditions.	i) A test report exists and concludes that each motor-operated valve changes position as indicated in Table 2.2.1-1 under design conditions.
	ii) Inspection will be performed for the existence of a report verifying that the as-installed motor-operated valves are bounded by the tests or type tests.	ii) A report exists and concludes that the as-installed motor-operated valves are bounded by the tests or type tests.
	iii) Tests of the as-installed motor-operated valves will be performed under preoperational flow, differential pressure, and temperature conditions.	iii) Each motor-operated valve changes position as indicated in Table 2.2.1-1 under pre-operational test conditions.
	iv) Exercise testing of the check valves with active safety functions identified in Table 2.2.1-1 will be performed under preoperational test pressure, temperature and fluid flow conditions.	iv) Each check valve changes position as indicated in Table 2.2.1-1.
11.b) After loss of motive power, the remotely operated valves identified in Table 2.2.1-1 assume the indicated loss of motive power position.	Testing of the installed valves will be performed under the conditions of loss of motive power.	After loss of motive power, each remotely operated valve identified in Table 2.2.1-1 assumes the indicated loss of motive power position.

Table 2.2.1-4

Component Name	Tag. No.	Component Location
Containment Vessel	CNS-MV-01	Shield Building

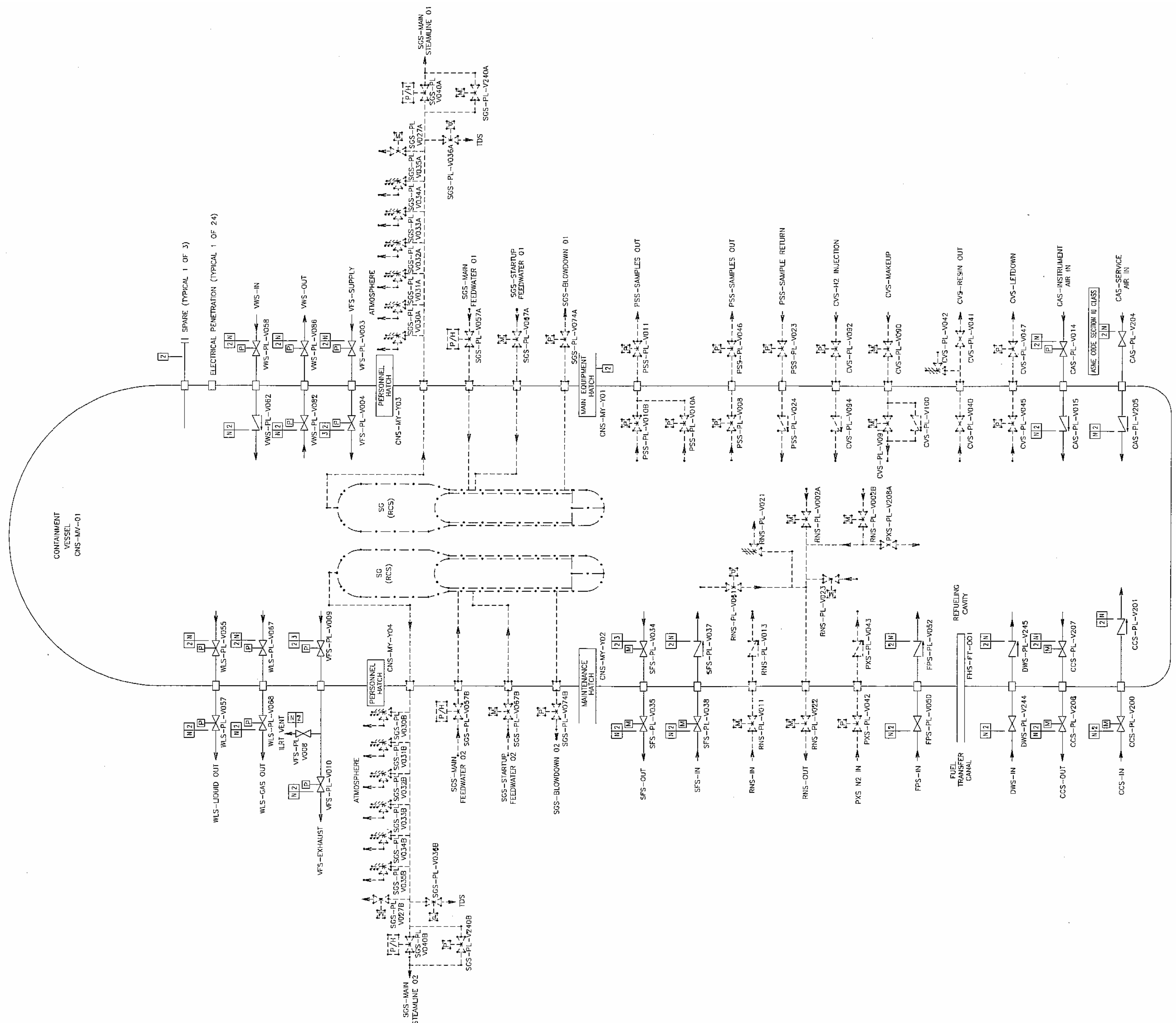


Figure 2.2.1-1
Containment System

2.2.2 Passive Containment Cooling System

Design Description

The passive containment cooling system (PCS) removes heat from the containment during design basis events.

The PCS is as shown in Figure 2.2.2-1 and the component locations of the PCS are as shown in Table 2.2.2-4.

1. The functional arrangement of the PCS is as described in the Design Description of this Section 2.2.2.

2. a) The components identified in Table 2.2.2-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.

   b) The pipelines identified in Table 2.2.2-2 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.

3. a) Pressure boundary welds in components identified in Table 2.2.2-1 as ASME Code Section III meet ASME Code Section III requirements.

   b) Pressure boundary welds in the pipelines identified in Table 2.2.2-2 as ASME Code Section III meet ASME Code Section III requirements.

4. a) The components identified in Table 2.2.2-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.

   b) The pipelines identified in Table 2.2.2-2 as ASME Code Section III retain their pressure boundary integrity at their design pressure.

5. a) The seismic Category I components identified in Table 2.2.2-1 can withstand seismic design basis loads without loss of safety function.

   b) Each of the pipelines identified in Table 2.2.2-2 for which functional capability is required is designed to withstand combined normal and seismic design basis loads without a loss of its functional capability.

   c) The passive containment cooling ancillary water storage tank (PCCAWST) can withstand a seismic event.

6. a) The Class 1E components identified in Table 2.2.2-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.

   b) The Class 1E components identified in Table 2.2.2-1 are powered from their respective Class 1E division.

c) Separation is provided between PCS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.

7. The PCS performs the following safety-related functions:

   a) The PCS delivers water from the PCCWST to the outside, top of the containment vessel.

   b) The PCS wets the outside surface of the containment vessel. The inside and outside of the containment vessel above the operating deck are coated with an inorganic zinc material.

   c) The PCS provides air flow over the outside of the containment vessel by a natural circulation air flow path from the air inlets to the air discharge structure.

   d) The PCS drains the excess water from the outside of the containment vessel through the two upper annulus drains.

   e) The PCS provides a flow path for long-term water makeup to the passive containment cooling water storage tank (PCCWST).

   f) The PCS provides a flow path for long-term water makeup from the PCCWST to the spent fuel pool.

8. The PCS performs the following nonsafety-related functions:

   a) The PCCAWST contains an inventory of cooling water sufficient for PCS containment cooling from hour 72 through day 7.

   b) The PCS delivers water from the PCCAWST to the PCCWST and spent fuel pool simultaneously.

   c) The PCCWST includes a water inventory for the fire protection system.

9. Safety-related displays identified in Table 2.2.2-1 can be retrieved in the main control room (MCR).

10. a) Controls exist in the MCR to cause the remotely operated valves identified in Table 2.2.2-1 to perform active functions.

   b) The valves identified in Table 2.2.2-1 as having protection and safety monitoring system (PMS) control perform an active safety function after receiving a signal from the PMS.

   c) The valves identified in Table 2.2.2-1 as having diverse actuation system (DAS) control perform an active safety function after receiving a signal from the DAS.

11. a) The motor-operated valves identified in Table 2.2.2-1 perform an active safety-related function to change position as indicated in the table.

   b) After loss of motive power, the remotely operated valves identified in Table 2.2.2-1 assume the indicated loss of motive power position.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.2.2-3 specifies the inspections, tests, analyses, and associated acceptance criteria for the PCS.

Table 2.2.2-1									
Component Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS/DAS**	**Active Function**	**Loss of Motive Power Position**
PCCWST	PCS-MT-01	No	Yes	-	-	-	-	-	-
Water Distribution Bucket	PCS-MT-03	No	Yes	-	-	-	-	-	-
Water Distribution Wiers	PCS-MT-04	No	Yes	-	-	-	-	-	-
PCCWST Isolation Valve	PCS-PL-V001A	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/Yes	Transfer Open	Open
PCCWST Isolation Valve	PCS-PL-V001B	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/Yes	Transfer Open	Open
PCCWST Isolation Valve	PCS-PL-V001C	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/Yes	Transfer Open	As Is
PCCWST Isolation Block MOV	PCS-PL-V002A	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Open	As Is
PCCWST Isolation Block MOV	PCS-PL-V002B	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Open	As Is
PCCWST Isolation Block MOV	PCS-PL-V002C	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Open	As Is
PCS Recirculation Loop Isolation Valve	PCS-PL-V023	Yes	Yes	-	-/No	No	-	Transfer Close	-
PCCWST Supply to Fire Protection System Isolation Valve	PCS-PL-V005	Yes	Yes	-	-/No	No	-	Transfer Close	-

Note: Dash (-) indicates not applicable.

Table 2.2.2-1 (cont.)									
Component Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS/DAS**	**Active Function**	**Loss of Motive Power Position**
PCS Makeup to SFS Isolation Valve	PCS-PL-V009	Yes	Yes	-	-/No	No	-	Transfer Open/ Transfer Close	-
Water Makeup Isolation Valve	PCS-PL-V044	Yes	Yes	-	-/No	No	-	Transfer Open	-
PCS Water Delivery Flow Sensor	PCS-001	No	Yes	-	Yes/No	Yes	-	-	-
PCS Water Delivery Flow Sensor	PCS-002	No	Yes	-	Yes/No	Yes	-	-	-
PCS Water Delivery Flow Sensor	PCS-003	No	Yes	-	Yes/No	Yes	-	-	-
PCS Water Delivery Flow Sensor	PCS-004	No	Yes	-	Yes/No	Yes	-	-	-
Containment Pressure Sensor	PCS-005	No	Yes	-	Yes/Yes	Yes	-	-	-
Containment Pressure Sensor	PCS-006	No	Yes	-	Yes/Yes	Yes	-	-	-
Containment Pressure Sensor	PCS-007	No	Yes	-	Yes/Yes	Yes	-	-	-
Containment Pressure Sensor	PCS-008	No	Yes	-	Yes/Yes	Yes	-	-	-
PCCWST Water Level Sensor	PCS-010	No	Yes	-	Yes/No	Yes	-	-	-
PCCWST Water Level Sensor	PCS-011	No	Yes	-	Yes/No	Yes	-	-	-

Table 2.2.2-1 (cont.)									
Component Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS/DAS**	**Active Function**	**Loss of Motive Power Position**
High-range Containment Pressure Sensor	PCS-012	No	Yes	-	Yes/Yes	Yes	-	-	-
High-range Containment Pressure Sensor	PCS-013	No	Yes	-	Yes/Yes	Yes	-	-	-
High-range Containment Pressure Sensor	PCS-014	No	Yes	-	Yes/Yes	Yes	-	-	-

Note: Dash (-) indicates not applicable.

Table 2.2.2-2			
Pipeline Name	**Line Number**	**ASME Code Section III**	**Functional Capability Required**
PCCWST Discharge Lines	PCS-PL-L001A/B/C/D	Yes	Yes
PCCWST Discharge Cross-connect Line	PCS-PL-L002	Yes	Yes
PCCWST Discharge Line	PCS-PL-L005	Yes	Yes
PCCWST Discharge Header Lines	PCS-PL-L003A, L003B	Yes	Yes
Post-72-hour PCCWST Makeup Supply Line Connections	PCS-PL-L004 PCS-PL-L051	Yes	Yes
Post-72-hour PCCWST Makeup Supply Lines	PCS-PL-L029 PCS-PL-L054	Yes	Yes
Post-72-hour SFS Makeup Lines	PCS-PL-L017 PCS-PL-L049	Yes	Yes

Table 2.2.2-3 Inspections, Tests, Analyses, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The functional arrangement of the PCS is as described in the Design Description of this Section 2.2.2.	Inspection of the as-built system will be performed.	The as-built PCS conforms to the functional arrangement as described in the Design Description of this Section 2.2.2.
2.a) The components identified in Table 2.2.2-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built components as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built components identified in Table 2.2.2-1 as ASME Code Section III.
2.b) The pipelines identified in Table 2.2.2-2 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built piping as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built piping identified in Table 2.2.2-2 as ASME Code Section III.
3.a) Pressure boundary welds in components identified in Table 2.2.2-1 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
3.b) Pressure boundary welds in the pipelines identified in Table 2.2.2-2 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
4.a) The components identified in Table 2.2.2-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.	A hydrostatic test will be performed on the components required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the components identified in Table 2.2.2-1 as ASME Code Section III conform with the requirements of the ASME Code Section III.

Table 2.2.2-3 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4.b) The pipelines identified in Table 2.2.2-2 as ASME Code Section III retain their pressure boundary integrity at their design pressure.	A hydrostatic test will be performed on the piping required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the piping identified in Table 2.2.2-2 as ASME Code Section III conform with the requirements of the ASME Code Section III.
5.a) The seismic Category I components identified in Table 2.2.2-1 can withstand seismic design basis loads without loss of safety function.	i) Inspection will be performed to verify that the seismic Category I components and valves identified in Table 2.2.2-1 are located on the Nuclear Island.	i) The seismic Category I components identified in Table 2.2.2-1 are located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I components will be performed.	ii) A report exists and concludes that the seismic Category I components can withstand seismic design basis loads without loss of safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed components including anchorage are seismically bounded by the tested or analyzed conditions.	iii) The report exists and concludes that the as-installed components including anchorage are seismically bounded by the tested or analyzed conditions.
5.b) Each of the pipelines identified in Table 2.2.2-2 for which functional capability is required is designed to withstand combined normal and seismic design basis loads without a loss of its functional capability.	Inspection will be performed for the existence of a report concluding that the as-built pipelines meet the requirements for functional capability.	A report exists and concludes that each of the as-built pipelines identified in Table 2.2.2-2 for which functional capability is required meets the requirements for functional capability.
5.c) The PCCAWST can withstand a seismic event.	Inspection will be performed for the existence of a report verifying that the as-installed PCCAWST and its anchorage are designed using seismic Category II methods and criteria.	A report exists and concludes that the as-installed PCCAWST and its anchorage are designed using seismic Category II methods and criteria.

Table 2.2.2-3 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6.a) The Class 1E components identified in Table 2.2.2-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.	i) Type tests or a combination of type tests and analyses will be performed on Class 1E components located in a harsh environment.	i) A report exists and concludes that the Class 1E components identified in Table 2.2.2-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.
	ii) Inspection will be performed of the as-installed Class 1E components and the associated wiring, cables, and terminations located in a harsh environment.	ii) A report exists and concludes that the as-installed Class 1E components and the associated wiring, cables, and terminations identified in Table 2.2.2-1 as being qualified for a harsh environment are bounded by type tests, analyses, or a combination of type tests and analyses.
6.b) The Class 1E components identified in Table 2.2.2-1 are powered from their respective Class 1E division.	Testing will be performed by providing a simulated test signal in each Class 1E division.	A simulated test signal exists at the Class 1E components identified in Table 2.2.2-1 when the assigned Class 1E division is provided the test signal.
6.c) Separation is provided between PCS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.	See Tier 1 Material, Table 3.3-6, item 7.d.	See Tier 1 Material, Table 3.3-6, item 7.d.

Table 2.2.2-3 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7.a) The PCS delivers water from the PCCWST to the outside, top of the containment vessel.	i) Testing will be performed to measure the PCCWST delivery rate from each one of the three parallel flow paths.	i) When tested, each one of the three flow paths delivers water at greater than or equal to: – 469.1 gpm at a PCCWST water level of 27.4 ft + 0.2, - 0.0 ft above the tank floor – 226.6 gpm when the PCCWST water level uncovers the first (i.e. tallest) standpipe – 176.3 gpm when the PCCWST water level uncovers the second tallest standpipe – 144.2 gpm when the PCCWST water level uncovers the third tallest standpipe
	ii) Testing and or analysis will be performed to demonstrate the PCCWST inventory provides 72 hours of adequate water flow.	ii) When tested and/or analyzed with all flow paths delivering and an initial water level at 27.4 + 0.2, - 0.00 ft, the PCCWST water inventory provides greater than or equal to 72 hours of flow, and the flow rate at 72 hours is greater than or equal to 100.7 gpm.
	iii) Inspection will be performed to determine the PCCWST standpipes elevations.	iii) The elevations of the standpipes above the tank floor are: – 16.8 ft ± 0.2 ft – 20.3 ft ± 0.2 ft – 24.1 ft ± 0.2 ft

Table 2.2.2-3 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7.b) The PCS wets the outside surface of the containment vessel. The inside and the outside of the containment vessel above the operating deck are coated with an inorganic zinc material.	i) Testing will be performed to measure the outside wetted surface of the containment vessel with one of the three parallel flow paths delivering water to the top of the containment vessel.	i) A report exists and concludes that when the water in the PCCWST uncovers the standpipes at the following levels, the water delivered by one of the three parallel flow paths to the containment shell provides coverage measured at the spring line that is equal to or greater than the stated coverages. - 24.1 ± 0.2 ft above the tank floor; at least 90% of the perimeter is wetted. - 20.3 ± 0.2 ft above the tank floor; at least 72.9% of the perimeter is wetted. - 16.8 ± 0.2 ft above the tank floor; at least 59.6% of the perimeter is wetted.
	ii) Inspection of the containment vessel exterior coating will be conducted.	ii) A report exists and concludes that the containment vessel exterior surface is coated with an inorganic zinc coating above elevation 135'-3".
	iii) Inspection of the containment vessel interior coating will be conducted.	iii) A report exists and concludes that the containment vessel interior surface is coated with an inorganic zinc coating above 7' above the operating deck.
7.c) The PCS provides air flow over the outside of the containment vessel by a natural circulation air flow path from the air inlets to the air discharge structure.	Inspections of the air flow path segments will be performed.	Flow paths exist at each of the following locations: – Air inlets – Base of the outer annulus – Base of the inner annulus – Discharge structure
7.d) The PCS drains the excess water from the outside of the containment vessel through the two upper annulus drains.	Testing will be performed to verify the upper annulus drain flow performance.	With a water level within the upper annulus 10" ± 1" above the annulus drain inlet, the flow rate through each drain is greater than or equal to 525 gpm.

Table 2.2.2-3 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7.e) The PCS provides a flow path for long-term water makeup to the PCCWST.	i) See item 1 in this table. ii) Testing will be performed to measure the delivery rate from the long-term makeup connection to the PCCWST.	i) See item 1 in this table. ii) With a water supply connected to the PCS long-term makeup connection, each PCS recirculation pump delivers greater than or equal to 100 gpm when tested separately.
7.f) The PCS provides a flow path for long-term water makeup from the PCCWST to the spent fuel pool.	i) Testing will be performed to measure the delivery rate from the PCCWST to the spent fuel pool. ii) Inspection of the PCCWST will be performed.	i) With the PCCWST water level at 27.4 ft + 0.2, - 0.0 ft above the bottom of the tank, the flow path from the PCCWST to the spent fuel pool delivers greater than or equal to 118 gpm. ii) The volume of the PCCWST is greater than 756,700 gallons.
8.a) The PCCAWST contains an inventory of cooling water sufficient for PCS containment cooling from hour 72 through day 7.	Inspection of the PCCAWST will be performed.	The volume of the PCCAWST is greater than 780,000 gallons.
8.b) The PCS delivers water from the PCCAWST to the PCCWST and spent fuel pool simultaneously.	Testing will be performed to measure the delivery rate from the PCCAWST to the PCCWST and spent fuel pool simultaneously.	With PCCASWST aligned to the suction of the recirculation pumps, each pump delivers greater than or equal to 100 gpm to the PCCWST and 35 gpm to the spent fuel pool simultaneously when each pump is tested separately.
8.c) The PCCWST includes a water inventory for the fire protection system.	See Tier 1 Material, Table 2.3.4-2, items 1 and 2.	See Tier 1 Material, Table 2.3.4-2, items 1 and 2.
9. Safety-related displays identified in Table 2.2.2-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the safety-related displays in the MCR.	Safety-related displays identified in Table 2.2.2-1 can be retrieved in the MCR.
10.a) Controls exist in the MCR to cause the remotely operated valves identified in Table 2.2.2-1 to perform active functions.	Stroke testing will be performed on the remotely operated valves identified in Table 2.2.2-1 using the controls in the MCR.	Controls in the MCR operate to cause remotely operated valves identified in Table 2.2.2-1 to perform active functions.

Table 2.2.2-3 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
10.b) The valves identified in Table 2.2.2-1 as having PMS control perform an active safety function after receiving a signal from the PMS.	Testing will be performed on the remotely operated valves in Table 2.2.2-1 using real or simulated signals into the PMS.	The remotely operated valves identified in Table 2.2.2-1 as having PMS control perform the active function identified in the table after receiving a signal from the PMS.
10.c) The valves identified in Table 2.2.2-1 as having DAS control perform an active safety function after receiving a signal from the DAS.	Testing will be performed on the remotely operated valves listed in Table 2.2.2-1 using real or simulated signals into the DAS.	The remotely operated valves identified in Table 2.2.2-1 as having DAS control perform the active function identified in the table after receiving a signal from the DAS.
11.a) The motor-operated valves identified in Table 2.2.2-1 perform an active safety-related function to change position as indicated in the table.	i) Tests or type tests of motor-operated valves will be performed to demonstrate the capability of the valve to operate under its design conditions.	i) A test report exists and concludes that each motor-operated valve changes position as indicated in Table 2.2.2-1 under design conditions.
	ii) Inspection will be performed for the existence of a report verifying that the capability of the as-installed motor-operated valves bound the tested conditions.	ii) A report exists and concludes that the capability of the as-installed motor-operated valves bound the tested conditions.
	iii) Tests of the as-installed motor-operated valves will be performed under preoperational flow, differential pressure, and temperature conditions.	iii) Each motor-operated valve changes position as indicated in Table 2.2.2-1 under preoperational test conditions.
11.b) After loss of motive power, the remotely operated valves identified in Table 2.2.2-1 assume the indicated loss of motive power position.	Testing of the installed valves will be performed under the conditions of loss of motive power.	After loss of motive power, each remotely operated valve identified in Table 2.2.2-1 assumes the indicated loss of motive power position.

Table 2.2.2-4		
Component Name	**Tag No.**	**Component Location**
PCCWST	PCS-MT-01	Shield Building
PCCAWST	PCS-MT-05	Yard
Recirculation Pump A	PCS-MP-01A	Auxiliary Building
Recirculation Pump B	PCS-MP-01B	Auxiliary Building

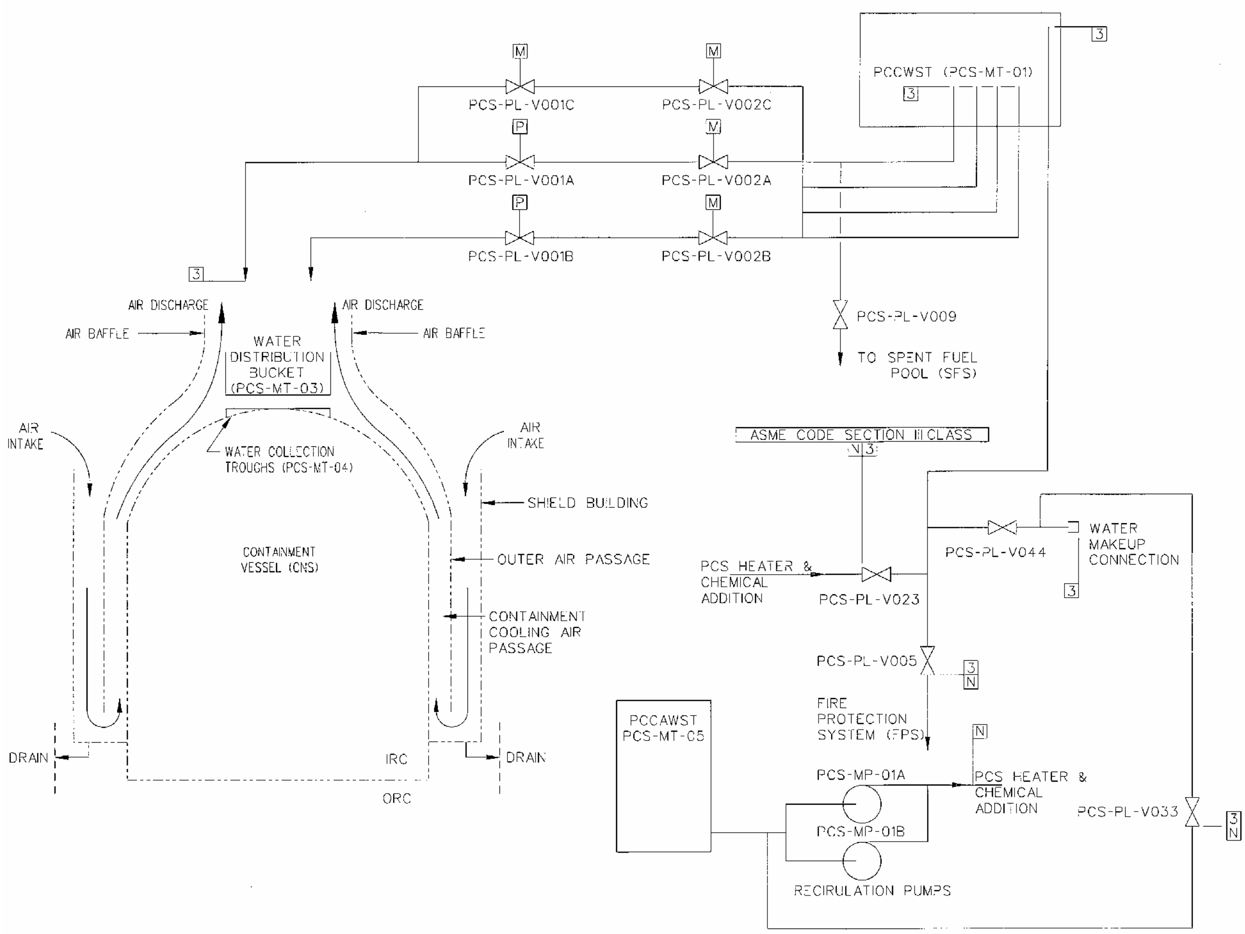


Figure 2.2.2-1
Passive Containment Cooling System

2.2.3 Passive Core Cooling System

Design Description

The passive core cooling system (PXS) provides emergency core cooling during design basis events.

The PXS is as shown in Figure 2.2.3-1 and the component locations of the PXS are as shown in Table 2.2.3-5.

1. The functional arrangement of the PXS is as described in the Design Description of this Section 2.2.3.

2. a) The components identified in Table 2.2.3-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.

   b) The piping identified in Table 2.2.3-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.

3. a) Pressure boundary welds in components identified in Table 2.2.3-1 as ASME Code Section III meet ASME Code Section III requirements.

   b) Pressure boundary welds in piping identified in Table 2.2.3-2 as ASME Code Section III meet ASME Code Section III requirements.

4. a) The components identified in Table 2.2.3-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.

   b) The piping identified in Table 2.2.3-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.

5. a) The seismic Category I equipment identified in Table 2.2.3-1 can withstand seismic design basis loads without loss of safety function.

   b) Each of the lines identified in Table 2.2.3-2 for which functional capability is required is designed to withstand combined normal and seismic design basis loads without a loss of its functional capability.

6. Each of the as-built lines identified in Table 2.2.3-2 as designed for leak before break (LBB) meets the LBB criteria, or an evaluation is performed of the protection from the dynamic effects of a rupture of the line.

7. a) The Class 1E equipment identified in Table 2.2.3-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.

   b) The Class 1E components identified in Table 2.2.3-1 are powered from their respective Class 1E division.

c) Separation is provided between PXS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.

8. The PXS provides the following safety-related functions:

   a) The PXS provides containment isolation of the PXS lines penetrating the containment.

   b) The PRHR HX provides core decay heat removal during design basis events.

   c) The CMTs, accumulators, in-containment refueling water storage tank (IRWST) and containment recirculation provide reactor coolant system (RCS) makeup, boration, and safety injection during design basis events.

   d) The PXS provides pH adjustment of water flooding the containment following design basis accidents.

9. The PXS has the following features:

   a) The PXS provides a function to cool the outside of the reactor vessel during a severe accident.

   b) The accumulator discharge check valves (PXS-PL-V028A/B and V029A/B) are of a different check valve type than the CMT discharge check valves (PXS-PL-V016A/B and V017A/B).

   c) The equipment listed in Table 2.2.3-6 has sufficient thermal lag to withstand the effects of identified hydrogen burns associated with severe accidents.

10. Safety-related displays of the parameters identified in Table 2.2.3-1 can be retrieved in the main control room (MCR).

11. a) Controls exist in the MCR to cause the remotely operated valves identified in Table 2.2.3-1 to perform their active function(s).

   b) The valves identified in Table 2.2.3-1 as having protection and safety monitoring system (PMS) control perform their active function after receiving a signal from the PMS.

   c) The valves identified in Table 2.2.3-1 as having diverse actuation system (DAS) control perform their active function after receiving a signal from the DAS.

12. a) The motor-operated and check valves identified in Table 2.2.3-1 perform an active safety-related function to change position as indicated in the table.

   b) After loss of motive power, the remotely operated valves identified in Table 2.2.3-1 assume the indicated loss of motive power position.

13. Displays of the parameters identified in Table 2.2.3-3 can be retrieved in the MCR.

Inspection, Tests, Analyses, and Acceptance Criteria

Table 2.2.3-4 specifies the inspections, tests, analyses, and associated acceptance criteria for the PXS.

Table 2.2.3-1									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. Harsh Envir.**	**Safety-Related Display**	**Control PMS/ DAS**	**Active Function**	**Loss of Motive Power Position**
Passive Residual Heat Removal Heat Exchanger (PRHR HX)	PXS-ME-01	Yes	Yes	-	- / -	-	- / -	-	-
Accumulator Tank A	PXS-MT-01A	Yes	Yes	-	- / -	-	- / -	-	-
Accumulator Tank B	PXS-MT-01B	Yes	Yes	-	- / -	-	- / -	-	-
Core Makeup Tank (CMT) A	PXS-MT-02A	Yes	Yes	-	- / -	-	- / -	-	-
CMT B	PXS-MT-02B	Yes	Yes	-	- / -	-	- / -	-	-
IRWST	PXS-MT-03	No	Yes	-	- / -	-	- / -	-	-
IRWST Screen A	PXS-MY-Y01A	No	Yes	-	- / -	-	- / -	-	-
IRWST Screen B	PXS-MY-Y01B	No	Yes	-	- / -	-	- / -	-	-
Containment Recirculation Screen A	PXS-MY-Y02A	No	Yes	-	- / -	-	- / -	-	-
Containment Recirculation Screen B	PXS-MY-Y02B	No	Yes	-	- / -	-	- / -	-	-
pH Adjustment Basket A	PXS-MY-Y03A	No	Yes	-	- / -	-	- / -	-	-
pH Adjustment Basket B	PXS-MY-Y03B	No	Yes	-	- / -	-	- / -	-	-
CMT A Inlet Isolation Motor-operated Valve	PXS-PL-V002A	Yes	Yes	Yes	Yes/Yes	Yes (Position)	Yes/No	None	As Is
CMT B Inlet Isolation Motor-operated Valve	PXS-PL-V002B	Yes	Yes	Yes	Yes/Yes	Yes (Position)	Yes/No	None	As Is

Note: Dash (-) indicates not applicable.

Table 2.2.3-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. Harsh Envir.**	**Safety-Related Display**	**Control PMS/ DAS**	**Active Function**	**Loss of Motive Power Position**
CMT A Discharge Isolation Valve	PXS-PL-V014A	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	Open
CMT B Discharge Isolation Valve	PXS-PL-V014B	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	Open
CMT A Discharge Isolation Valve	PXS-PL-V015A	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	Open
CMT B Discharge Isolation Valve	PXS-PL-V015B	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	Open
CMT A Discharge Check Valve	PXS-PL-V016A	Yes	Yes	No	- / -	No	- / -	Transfer Open/ Transfer Closed	-
CMT B Discharge Check Valve	PXS-PL-V016B	Yes	Yes	No	- / -	No	- / -	Transfer Open/ Transfer Closed	-
CMT A Discharge Check Valve	PXS-PL-V017A	Yes	Yes	No	- / -	No	- / -	Transfer Open/ Transfer Closed	-
CMT B Discharge Check Valve	PXS-PL-V017B	Yes	Yes	No	- / -	No	- / -	Transfer Open/ Transfer Closed	-

Note: Dash (-) indicates not applicable.

Table 2.2.3-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. Harsh Envir.**	**Safety-Related Display**	**Control PMS/ DAS**	**Active Function**	**Loss of Motive Power Position**
Accumulator A Pressure Relief Valve	PXS-PL-V022A	Yes	Yes	No	- / -	No	- / -	Transfer Open/ Transfer Closed	-
Accumulator B Pressure Relief Valve	PXS-PL-V022B	Yes	Yes	No	- / -	No	- / -	Transfer Open/ Transfer Closed	-
Accumulator A Discharge Check Valve	PXS-PL-V028A	Yes	Yes	No	- / -	No	- / -	Transfer Open	-
Accumulator B Discharge Check Valve	PXS-PL-V028B	Yes	Yes	No	- / -	No	- / -	Transfer Open	-
Accumulator A Discharge Check Valve	PXS-PL-V029A	Yes	Yes	No	- / -	No	- / -	Transfer Open	-
Accumulator B Discharge Check Valve	PXS-PL-V029B	Yes	Yes	No	- / -	No	- / -	Transfer Open	-
Nitrogen Supply Containment Isolation Valve	PXS-PL-V042	Yes	Yes	Yes	Yes/No	Yes (position)	Yes/No	Transfer Closed	Close
Nitrogen Supply Containment Isolation Check Valve	PXS-PL-V043	Yes	Yes	No	- / -	No	- / -	Transfer Closed	-
PRHR HX Inlet Isolation Motor-operated Valve	PXS-PL-V101	Yes	Yes	Yes	Yes/Yes	Yes (position)	Yes/No	None	As Is

Note: Dash (-) indicates not applicable.

Table 2.2.3-1 (cont.)

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. Harsh Envir.	Safety-Related Display	Control PMS/ DAS	Active Function	Loss of Motive Power Position
PRHR HX Control Valve	PXS-PL-V108A	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	Open
PRHR HX Control Valve	PXS-PL-V108B	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	Open
Containment Recirculation A Isolation Motor-operated Valve	PXS-PL-V117A	Yes	Yes	Yes	Yes/Yes	Yes (position)	Yes/Yes	Transfer Open	As Is
Containment Recirculation B Isolation Motor-operated Valve	PXS-PL-V117B	Yes	Yes	Yes	Yes/Yes	Yes (position)	Yes/Yes	Transfer Open	As Is
Containment Recirculation A Squib Valve	PXS-PL-V118A	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	As Is
Containment Recirculation B Squib Valve	PXS-PL-V118B	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	As Is
Containment Recirculation A Check Valve	PXS-PL-V119A	Yes	Yes	No	- / -	No	- / -	Transfer Open	-
Containment Recirculation B Check Valve	PXS-PL-V119B	Yes	Yes	No	- / -	No	- / -	Transfer Open	-
Containment Recirculation A Squib Valve	PXS-PL-V120A	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	As Is
Containment Recirculation B Squib Valve	PXS-PL-V120B	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	As Is

Note: Dash (-) indicates not applicable.

Table 2.2.3-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. Harsh Envir.**	**Safety-Related Display**	**Control PMS/ DAS**	**Active Function**	**Loss of Motive Power Position**
IRWST Injection A Check Valve	PXS-PL-V122A	Yes	Yes	No	- / -	No	- / -	Transfer Open	-
IRWST Injection B Check Valve	PXS-PL-V122B	Yes	Yes	No	- / -	No	- / -	Transfer Open	-
IRWST Injection A Squib Valve	PXS-PL-V123A	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	As Is
IRWST Injection B Squib Valve	PXS-PL-V123B	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	As Is
IRWST Injection A Check Valve	PXS-PL-V124A	Yes	Yes	No	- / -	No	- / -	Transfer Open	-
IRWST Injection B Check Valve	PXS-PL-V124B	Yes	Yes	No	- / -	No	- / -	Transfer Open	-
IRWST Injection A Squib Valve	PXS-PL-V125A	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	As Is
IRWST Injection B Squib Valve	PXS-PL-V125B	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Open	As Is
IRWST Gutter Isolation Valve	PXS-PL-V130A	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Closed	Closed
IRWST Gutter Isolation Valve	PXS-PL-V130B	Yes	Yes	Yes	Yes/Yes	No	Yes/Yes	Transfer Closed	Closed
CMT A Level Sensor	PXS-011A	-	Yes	-	Yes/Yes	Yes	- / -	-	-
CMT A Level Sensor	PXS-011B	-	Yes	-	Yes/Yes	Yes	- / -	-	-
CMT A Level Sensor	PXS-011C	-	Yes	-	Yes/Yes	Yes	- / -	-	-
CMT A Level Sensor	PXS-011D	-	Yes	-	Yes/Yes	Yes	- / -	-	-

Note: Dash (-) indicates not applicable.

Table 2.2.3-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. Harsh Envir.**	**Safety-Related Display**	**Control PMS/ DAS**	**Active Function**	**Loss of Motive Power Position**
CMT B Level Sensor	PXS-012A	-	Yes	-	Yes/Yes	Yes	-/-	-	-
CMT B Level Sensor	PXS-012B	-	Yes	-	Yes/Yes	Yes	-/-	-	-
CMT B Level Sensor	PXS-012C	-	Yes	-	Yes/Yes	Yes	-/-	-	-
CMT B Level Sensor	PXS-012D	-	Yes	-	Yes/Yes	Yes	-/-	-	-
CMT A Level Sensor	PXS-013A	-	Yes	-	Yes/Yes	Yes	-/-	-	-
CMT A Level Sensor	PXS-013B	-	Yes	-	Yes/Yes	Yes	-/-	-	-
CMT A Level Sensor	PXS-013C	-	Yes	-	Yes/Yes	Yes	-/-	-	-
CMT A Level Sensor	PXS-013D	-	Yes	-	Yes/Yes	Yes	-/-	-	-
CMT B Level Sensor	PXS-014A	-	Yes	-	Yes/Yes	Yes	- / -	-	-
CMT B Level Sensor	PXS-014B	-	Yes	-	Yes/Yes	Yes	- / -	-	-
CMT B Level Sensor	PXS-014C	-	Yes	-	Yes/Yes	Yes	- / -	-	-
CMT B Level Sensor	PXS-014D	-	Yes	-	Yes/Yes	Yes	- / -	-	-
IRWST Level Sensor	PXS-045	-	Yes	-	Yes/Yes	Yes	- / -	-	-
IRWST Level Sensor	PXS-046	-	Yes	-	Yes/Yes	Yes	- / -	-	-
IRWST Level Sensor	PXS-047	-	Yes	-	Yes/Yes	Yes	- / -	-	-
IRWST Level Sensor	PXS-048	-	Yes	-	Yes/Yes	Yes	- / -	-	-
PRHR HX Flow Sensor	PXS-049A	-	Yes	-	Yes/Yes	Yes	- / -	-	-
PRHR HX Flow Sensor	PXS-049B	-	Yes	-	Yes/Yes	Yes	- / -	-	-

Note: Dash (-) indicates not applicable.

Table 2.2.3-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. Harsh Envir.**	**Safety-Related Display**	**Control PMS/ DAS**	**Active Function**	**Loss of Motive Power Position**
Containment Flood-up Level Sensor	PXS-050	-	Yes	-	Yes/Yes	Yes	-/-	-	-
Containment Flood-up Level Sensor	PXS-051	-	Yes	-	Yes/Yes	Yes	-/-	-	-
Containment Flood-up Level Sensor	PXS-052	-	Yes	-	Yes/Yes	Yes	-/-	-	-

Note: Dash (-) indicates not applicable.

Table 2.2.3-2				
Line Name	**Line Number**	**ASME Code Section III**	**Leak Before Break**	**Functional Capability Required**
PRHR HX inlet line from hot leg and outlet line to steam generator channel head	RCS-L134, PXS-L102, PXS-L103, PXS-L104A, PXS-L104B, PXS-L105, RCS-L113	Yes	Yes	Yes
	PXS-L107	Yes	Yes	No
CMT A inlet line from cold leg C and outlet line to reactor vessel direct vessel injection (DVI) nozzle A	RCS-L118A, PXS-L007A, PXS-L015A, PXS-L016A, PXS-L017A, PXS-L018A, PXS-L020A, PXS-L021A	Yes	Yes	Yes
	PXS-L019A, PXS-L070A	Yes	Yes	No
CMT B inlet line from cold leg D and outlet line to reactor vessel DVI nozzle B	RCS-L118B, PXS-L007B, PXS-L015B, PXS-L016B, PXS-L017B, PXS-L018B, PXS-L020B, PXS-L021B	Yes	Yes	Yes
	PXS-L019B, PXS-L070B	Yes	Yes	No
Accumulator A discharge line to DVI line A	PXS-L025A, PXS-L027A, PXS-L029A	Yes	Yes	Yes
Accumulator B discharge line to DVI line B	PXS-L025B, PXS-L027B, PXS-L029B	Yes	Yes	Yes
IRWST injection line A to DVI line A	PXS-L125A, PXS-L127A	Yes	Yes	Yes
	PXS-L123A, PXS-L124A, PXS-L118A, PXS-L117A, PXS-L116A, PXS-L112A	Yes	No	Yes
IRWST injection line B to DVI line B	PXS-L125B, PXS-L127B	Yes	Yes	Yes
	PXS-L123B, PXS-L124B, PXS-L118B, PXS-L117B, PXS-L116B, PXS-L114B, PXS-L112B, PXS-L120	Yes	No	Yes

Table 2.2.3-2				
Line Name	**Line Number**	**ASME Code Section III**	**Leak Before Break**	**Functional Capability Required**
Containment recirculation line A	PXS-L113A, PXS-L131A, PXS-L132A	Yes	No	Yes
Containment recirculation line B	PXS-L113B, PXS-L131B, PXS-L132B	Yes	No	Yes
IRWST Gutter Drain Line	PXS-L142A, PXS-L142B	Yes	No	Yes
	PXS-L141A, PXS-L141B	Yes	No	No

Table 2.2.3-3			
Equipment	**Tag No.**	**Display**	**Control Function**
CMT A Discharge Isolation Valve (Position)	PXS-PL-V014A	Yes (Position)	-
CMT B Discharge Isolation Valve (Position)	PXS-PL-V014B	Yes (Position)	-
CMT A Discharge Isolation Valve (Position)	PXS-PL-V015A	Yes (Position)	-
CMT B Discharge Isolation Valve (Position)	PXS-PL-V015B	Yes (Position)	-
Accumulator A Nitrogen Vent Valve (Position)	PXS-PL-V021A	Yes (Position)	-
Accumulator B Nitrogen Vent Valve (Position)	PXS-PL-V021B	Yes (Position)	-
Accumulator A Discharge Isolation Valve (Position)	PXS-PL-V027A	Yes (Position)	-
Accumulator B Discharge Isolation Valve (Position)	PXS-PL-V027B	Yes (Position)	-
PRHR HX Control Valve (Position)	PXS-PL-V108A	Yes (Position)	-
PRHR HX Control Valve (Position)	PXS-PL-V108B	Yes (Position)	-
Containment Recirculation A Isolation Valve	PXS-PL-V017A	Yes (Position)	-
Containment Recirculation B Isolation Valve	PXS-PL-V017B	Yes (Position)	-
Containment Recirculation A Isolation Valve (Position)	PXS-PL-V118A	Yes (Position)	-
Containment Recirculation B Isolation Valve (Position)	PXS-PL-V118B	Yes (Position)	-
Containment Recirculation A Isolation Valve (Position)	PXS-PL-V120A	Yes (Position)	-
Containment Recirculation B Isolation Valve (Position)	PXS-PL-V120B	Yes (Position)	-
IRWST Line A Isolation Valve (Position)	PXS-PL-V121A	Yes (Position)	-
IRWST Line B Isolation Valve (Position)	PXS-PL-V121B	Yes (Position)	-
IRWST Injection A Isolation Squib (Position)	PXS-PL-V123A	Yes (Position)	-

Note: Dash (-) indicates not applicable.

Table 2.2.3-3 (cont.)			
Equipment	**Tag No.**	**Display**	**Control Function**
IRWST Injection B Isolation Squib (Position)	PXS-PL-V123B	Yes (Position)	-
IRWST Injection A Isolation Squib (Position)	PXS-PL-V125A	Yes (Position)	-
IRWST Injection B Isolation Squib (Position)	PXS-PL-V125B	Yes (Position)	-
IRWST Gutter Bypass Isolation Valve (Position)	PXS-PL-V130A	Yes (Position)	-
IRWST Gutter Bypass Isolation Valve (Position)	PXS-PL-V130B	Yes (Position)	-
Accumulator A Level Sensor	PXS-021	Yes	-
Accumulator B Level Sensor	PXS-022	Yes	-
Accumulator A Level Sensor	PXS-023	Yes	-
Accumulator B Level Sensor	PXS-024	Yes	-
PRHR HX Inlet Temperature Sensor	PXS-064	Yes	-
IRWST Surface Temperature Sensor	PXS-041	Yes	-
IRWST Surface Temperature Sensor	PXS-042	Yes	-
IRWST Bottom Temperature Sensor	PXS-043	Yes	-
IRWST Bottom Temperature Sensor	PXS-044	Yes	-

Note: Dash (-) indicates not applicable.

Table 2.2.3-4
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the PXS is as described in the Design Description of this Section 2.2.3.	Inspection of the as-built system will be performed.	The as-built PXS conforms with the functional arrangement as described in the Design Description of this Section 2.2.3.
2.a) The components identified in Table 2.2.3-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built components as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built components identified in Table 2.2.3-1 as ASME Code Section III.
2.b) The piping identified in Table 2.2.3-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built piping as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built piping identified in Table 2.2.3-2 as ASME Code Section III.
3.a) Pressure boundary welds in components identified in Table 2.2.3-1 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
3.b) Pressure boundary welds in piping identified in Table 2.2.3-2 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.

Table 2.2.3-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4.a) The components identified in Table 2.2.3-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.	A hydrostatic test will be performed on the components required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the components identified in Table 2.2.3-1 as ASME Code Section III conform with the requirements of the ASME Code Section III.
4.b) The piping identified in Table 2.2.3-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.	A hydrostatic test will be performed on the piping required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the piping identified in Table 2.2.3-2 as ASME Code Section III conform with the requirements of the ASME Code Section III.
5.a) The seismic Category I equipment identified in Table 2.2.3-1 can withstand seismic design basis loads without loss of safety function.	i) Inspection will be performed to verify that the seismic Category I equipment and valves identified in Table 2.2.3-1 are located on the Nuclear Island.	i) The seismic Category I equipment identified in Table 2.2.3-1 is located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis dynamic loads without loss of safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) A report exists and concludes that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.
5.b) Each of the lines identified in Table 2.2.3-2 for which functional capability is required is designed to withstand combined normal and seismic design basis loads without a loss of its functional capability.	Inspection will be performed verifying that the as-built piping meets the requirements for functional capability.	A report exists and concludes that each of the as-built lines identified in Table 2.2.3-2 for which functional capability is required meets the requirements for functional capability.

Table 2.2.3-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. Each of the as-built lines identified in Table 2.2.3-2 as designed for LBB meets the LBB criteria, or an evaluation is performed of the protection from the dynamic effects of a rupture of the line.	Inspection will be performed for the existence of an LBB evaluation report or an evaluation report on the protection from dynamic effects of a pipe break. Tier 1 Material, Section 3.3, Nuclear Island Buildings, contains the design descriptions and inspections, tests, analyses, and acceptance criteria for protection from the dynamic effects of pipe rupture.	An LBB evaluation report exists and concludes that the LBB acceptance criteria are met by the as-built RCS piping and piping materials, or a pipe break evaluation report exists and concludes that protection from the dynamic effects of a line break is provided.
7.a) The Class 1E equipment identified in Table 2.2.3-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.	i) Type tests, analyses, or a combination of type tests and analyses will be performed on Class 1E equipment located in a harsh environment.	i) A report exists and concludes that the Class 1E equipment identified in Table 2.2.3-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.
	ii) Inspection will be performed of the as-installed Class 1E equipment and the associated wiring, cables, and terminations located in a harsh environment.	ii) A report exists and concludes that the as-installed Class 1E equipment and the associated wiring, cables, and terminations identified in Table 2.2.3-1 as being qualified for a harsh environment are bounded by type tests, analyses, or a combination of type tests and analyses.
7.b) The Class 1E components identified in Table 2.2.3-1 are powered from their respective Class 1E division.	Testing will be performed by providing a simulated test signal in each Class 1E division.	A simulated test signal exists at the Class 1E equipment identified in Table 2.2.3-1 when the assigned Class 1E division is provided the test signal.
7.c) Separation is provided between PXS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.	See Tier 1 Material, Table 3.3-6, item 7.d.	See Tier 1 Material, Table 3.3-6, item 7.d.
8.a) The PXS provides containment isolation of the PXS lines penetrating the containment.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.

Table 2.2.3-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
8.b) The PXS provides core decay heat removal during design basis events.	A heat removal performance test and analysis of the PRHR HX will be performed to determine the heat transfer from the HX. For the test, the reactor coolant hot leg temperature will be initially at ≥ 540°F with the reactor coolant pumps stopped. The IRWST water level for the test will be above the top of the HX. The IRWST water temperature is not specified for the test. The test will continue until the hot leg temperature decreases below 420°F.	A report exists and concludes that the PRHR HX heat transfer rate with the design basis number of PRHR HX tubes plugged is: ≥ 1.78 x 10^8 Btu/hr with 520°F HL Temp and 80°F IRWST temperatures. ≥ 1.11 x 10^8 Btu/hr with 420°F HL Temp and 80°F IRWST temperatures.
	Inspection of the elevation of the PRHR HX will be conducted.	The elevation of the centerline of the HX's upper channel head is greater than the HL centerline by at least 26.3 ft.
8.c) The PXS provides RCS makeup, boration, and safety injection during design basis events.	i) A low-pressure injection test and analysis for each CMT, each accumulator, each IRWST injection line, and each containment recirculation line will be conducted. Each test is initiated by opening isolation valve(s) in the line being tested. Test fixtures may be used to simulate squib valves.	i) The injection line flow resistance from each source is as follows:
	CMTs: Each CMT will be initially filled with water. All valves in these lines will be open during the test.	CMTs: The calculated flow resistance between each CMT and the reactor vessel is ≥ 1.81 x 10^{-5} ft/gpm^2 and ≤ 2.25 x 10^{-5} ft/gpm^2.
	Accumulators: Each accumulator will be partially filled with water and pressurized with nitrogen. All valves in these lines will be open during the test. Sufficient flow will be provided to fully open the check valves.	Accumulators: The calculated flow resistance between each accumulator and the reactor vessel is ≥ 1.47 x 10^{-5} ft/gpm^2 and ≤ 1.83 x 10^{-5} ft/gpm^2.

Table 2.2.3-4 (cont.) Inspections, Tests, Analyses, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
	IRWST Injection: The IRWST will be partially filled with water. All valves in these lines will be open during the test. Sufficient flow will be provided to fully open the check valves.	IRWST Injection: The calculated flow resistance for each IRWST injection line between the IRWST and the reactor vessel is: Line A: $\geq 5.53 \times 10^{-6}$ ft/gpm^2 and $\leq 9.20 \times 10^{-6}$ ft/gpm^2 and Line B: $\geq 6.21 \times 10^{-6}$ ft/gpm^2 and $\leq 1.03 \times 10^{-5}$ ft/gpm^2.
	Containment Recirculation: A temporary water supply will be connected to the recirculation lines. All valves in these lines will be open during the test. Sufficient flow will be provided to fully open the check valves.	Containment Recirculation: The calculated flow resistance for each containment recirculation line between the containment and the reactor vessel is: Line A: $\leq 1.11 \times 10^{-5}$ ft/gpm^2 and Line B: $\leq 1.03 \times 10^{-5}$ ft/gpm^2.
	ii) A low-pressure test and analysis will be conducted for each CMT to determine piping flow resistance from the cold leg to the CMT. The test will be performed by filling the CMT via the cold leg balance line by operating the normal residual heat removal pumps.	ii) The flow resistance from the cold leg to the CMT is $\leq 7.21 \times 10^{-6}$ ft/gpm^2.

Table 2.2.3-4 (cont.) Inspections, Tests, Analyses, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
	iii) Inspections of the routing of the following pipe lines will be conducted: – CMT inlet line, cold leg to high point – PRHR HX inlet line, hot leg to high point	iii) These lines have no downward sloping sections between the connection to the RCS and the high point of the line.
	iv) Inspections of the elevation of the following pipe lines will be conducted: – IRWST injection lines; IRWST connection to DVI nozzles – Containment recirculation lines; containment to IRWST lines – CMT discharge lines to DVI connection – PRHR HX outlet line to SG connection	iv) The maximum elevation of the top inside surface of these lines is less than the elevation of: – IRWST bottom inside surface – IRWST bottom inside surface – CMT bottom inside surface – PRHR HX lower channel head top inside surface
	v) Inspections of the elevation of the following tanks will be conducted: – CMTs – IRWST	v) The elevation of the bottom inside tank surface is higher than the direct vessel injection nozzle centerline by the following: – CMTs $\geq$ 7.5 ft – IRWST $\geq$ 3.4 ft
	vi) Inspections of each of the following tanks will be conducted: – CMTs – Accumulators – IRWST	vi) The calculated volume of each of the following tanks is as follows: – CMTs $\geq$ 2487 ft^3 – Accumulators $\geq$ 2000 ft^3 – IRWST $\geq$ 73,900 ft^3 between the tank outlet connection and the tank overflow

Table 2.2.3-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
	vii) Inspection of the as-built components will be conducted for plates located above the containment recirculation screens.	vii) Plates located above each containment recirculation screen are no more than 1 ft above the top of the screen and extend out at least 10 ft perpendicular to and at least 7 ft to the side of the trash rack portion of the screen.
	viii) Inspections of the IRWST and containment recirculation screens will be conducted.	viii) The screen surface area (width x height) of each screen trash rack is $\geq$ 70 ft^2 and of each fine screen is $\geq$ 140 ft^2 (unfolded area). The bottom of the containment recirculation screens is $\geq$ 2 ft above the loop compartment floor.
	ix) Inspections will be conducted of the insulation used inside the containment on ASME Class 1 lines and on the reactor vessel, reactor coolant pumps, pressurizer and steam generators.	ix) The type of insulation used on these lines and equipment is a metal reflective type or a suitable equivalent.
	x) Inspections will be conducted of the as-built nonsafety-related coatings or of plant records of the nonsafety-related coatings used inside containment on walls, floors, ceilings, structural steel which is part of the building structure and on the polar crane.	x) A report exists and concludes that the coatings used on these surfaces has a dry film density of $\geq$ 100 lb/ft^3.
	xi) Inspection of the as-built CMT inlet diffuser will be conducted.	xi) The CMT inlet diffuser has a flow area $\geq$ 165 in^2.
	xii) Inspections will be conducted of the CMT level sensors (PSX-11A/B/D/C, - 12A/B/C/D, - 13A/B/C/D, - 14A/B/C/D) upper level tap lines.	xii) The centerline of each upper level tap line at the tee for each level sensor is located 1" $\pm$ 1" below the centerline of the upper level tap connection to the CMT.

Table 2.2.3-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
	xiii) Inspections will be conducted of the surfaces in the vicinity of the containment recirculation screens. The surfaces in the vicinity of the containment recirculation screens are the surfaces located above the bottom of the recirculation screens up to and including the bottom surface of the plate discussed in Table 2.2.3-4, item 8.c.vii, out at least 10 feet perpendicular to and at least 7 feet to the side of the trash rack portion of the screen.	xiii) These surfaces are stainless steel.
8.d) The PXS provides pH adjustment of water flooding the containment following design basis accidents.	Inspections of the pH adjustment baskets will be conducted.	pH adjustment baskets exist, with a total calculated volume ≥ 560 ft^3. The pH baskets are located below plant elevation 107 ft, 2 in.
9.a) The PXS provides a function to cool the outside of the reactor vessel during a severe accident.	i) A flow test and analysis for each IRWST drain line to the containment will be conducted. The test is initiated by opening isolation valves in each line. Test fixtures may be used to simulate squib valves. ii) Inspections of the as-built reactor vessel insulation will be performed.	i) The calculated flow resistance for each IRWST drain line between the IRWST and the containment is ≤ 4.07 x 10^{-6} ft/gpm^2. ii) The combined total flow area of the water inlets is not less than 6 ft^2. The combined total flow area of the steam outlet(s) is not less than 12 ft^2.

Table 2.2.3-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
	iii) Inspections will be conducted of the flow path(s) from the loop compartments to the reactor vessel cavity.	A report exists and concludes that the minimum flow area between the vessel insulation and reactor vessel for the flow path that vents steam is not less than 12 ft^2 considering the maximum deflection of the vessel insulation with a static pressure of 12.95 ft of water. iii) A flow path with a flow area not less than 6 ft^2 exists from the loop compartment to the reactor vessel cavity.
9.b) The accumulator discharge check valves (PXS-PL-V028A/B and V029A/B) are of a different check valve type than the CMT discharge check valves (PXS-PL-V016A/B and V017A/B).	An inspection of the accumulator and CMT discharge check valves is performed.	The accumulator discharge check valves are of a different check valve type than the CMT discharge check valves.
9.c) The equipment listed in Table 2.2.3-6 has sufficient thermal lag to withstand the effects of identified hydrogen burns associated with severe accidents.	Tests, analyses, or a combination of tests and analyses will be performed to determine the thermal lag of this equipment.	A report exists and concludes that the thermal lag of this equipment is greater than the value required.
10. Safety-related displays of the parameters identified in Table 2.2.3-1 can be retrieved in the MCR.	Inspection will be performed for the retrievability of the safety-related displays in the MCR.	Safety-related displays identified in Table 2.2.3-1 can be retrieved in the MCR.
11.a) Controls exist in the MCR to cause the remotely operated valves identified in Table 2.2.3-1 to perform their active function(s).	i) Testing will be performed on the squib valves identified in Table 2.2.3-1 using controls in the MCR, without stroking the valve. ii) Stroke testing will be performed on remotely operated valves other than squib valves identified in Table 2.2.3-1 using the controls in the MCR.	i) Controls in the MCR operate to cause a signal at the squib valve electrical leads that is capable of actuating the squib valve. ii) Controls in the MCR operate to cause remotely operated valves other than squib valves to perform their active functions.

Table 2.2.3-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
11.b) The valves identified in Table 2.2.3-1 as having PMS control perform their active function after receiving a signal from the PMS.	i) Testing will be performed on the squib valves identified in Table 2.2.3-1 using real or simulated signals into the PMS without stroking the valve. ii) Testing will be performed on the remotely operated valves other than squib valves identified in Table 2.2.3-1 using real or simulated signals into the PMS. iii) Testing will be performed to demonstrate that remotely operated PXS isolation valves PXS-V014A/B, V015A/B, V108A/B open within the required response times.	i) Squib valves receive an electrical signal at the valve electrical leads that is capable of actuating the valve after a signal is input to the PMS. ii) Remotely operated valves other than squib valves perform the active function identified in the table after a signal is input to the PMS. iii) These valves open within 20 seconds after receipt of an actuation signal.
11.c) The valves identified in Table 2.2.3-1 as having DAS control perform their active function after receiving a signal from the DAS.	i) Testing will be performed on the squib valves identified in Table 2.2.3-1 using real or simulated signals into the DAS without stroking the valve. ii) Testing will be performed on the remotely operated valves other than squib valves identified in Table 2.2.3-1 using real or simulated signals into the DAS.	i) Squib valves receive an electrical signal at the valve electrical leads that is capable of actuating the valve after a signal is input to the DAS. ii) Remotely operated valves other than squib valves perform the active function identified in Table 2.2.3-1 after a signal is input to the DAS.
12.a) The motor-operated and check valves identified in Table 2.2.3-1 perform an active safety-related function to change position as indicated in the table.	i) Tests or type tests of motor-operated valves will be performed that demonstrate the capability of the valve to operate under its design conditions. ii) Inspection will be performed for the existence of a report verifying that the as-installed motor-operated valves are bounded by the tests or type tests.	i) A test report exists and concludes that each motor-operated valve changes position as indicated in Table 2.2.3-1 under design conditions. ii) A report exists and concludes that the as-installed motor-operated valves are bounded by the tests or type tests.

Table 2.2.3-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
	iii) Tests of the as-installed motor-operated valves will be performed under preoperational flow, differential pressure, and temperature conditions. iv) Exercise testing of the check valves with active safety functions identified in Table 2.2.3-1 will be performed under preoperational test pressure, temperature and fluid flow conditions.	iii) Each motor-operated valve changes position as indicated in Table 2.2.3-1 under preoperational test conditions. iv) Each check valve changes position as indicated in Table 2.2.3-1.
12.b) After loss of motive power, the remotely operated valves identified in Table 2.2.3-1 assume the indicated loss of motive power position.	Testing of the installed valves will be performed under the conditions of loss of motive power.	After loss of motive power, each remotely operated valve identified in Table 2.2.3-1 assumes the indicated loss of motive power position.
13. Displays of the parameters identified in Table 2.2.3-3 can be retrieved in the MCR.	Inspection will be performed for retrievability of the displays identified in Table 2.2.3-3 in the MCR.	Displays identified in Table 2.2.3-3 can be retrieved in the MCR.

Table 2.2.3-5		
Component Name	**Tag No.**	**Component Location**
Passive Residual Heat Removal Heat Exchanger (PRHR HX)	PXS-ME-01	Containment Building
Accumulator Tank A	PXS-MT-01A	Containment Building
Accumulator Tank B	PXS-MT-01B	Containment Building
Core Makeup Tank (CMT) A	PXS-MT-02A	Containment Building
CMT B	PXS-MT-02B	Containment Building
IRWST	PXS-MT-03	Containment Building
IRWST Screen A	PXS-MY-Y01A	Containment Building
IRWST Screen B	PXS-MY-Y01B	Containment Building
Containment Recirculation Screen A	PXS-MY-Y02A	Containment Building
Containment Recirculation Screen B	PXS-MY-Y02B	Containment Building
pH Adjustment Basket A	PXS-MY-Y03A	Containment Building
pH Adjustment Basket B	PXS-MY-Y03B	Containment Building

Table 2.2.3-6		
Equipment	**Tag No.**	**Function**
Containment Air Sample Containment Isolation Valve IRC	PSS-PL-V001A/B, 010A/B	Transfer open
Containment Pressure Sensors	PCS-012, 013, 014	Sense pressure
RCS Wide Range Pressure Sensors	RCS-191A, B, C, D	Sense pressure
SG1 Wide Range Level Sensors	SGS-011, 012, 015, 016	Sense level
SG2 Wide Range Level Sensors	SGS-013, 014, 017, 018	Sense level
Hydrogen Monitors	VLS-001, 002, 003	Sense concentration
Hydrogen Igniters	VLS-EH-01 through 64	Ignite hydrogen
Containment Electrical Penetrations	P01, P02, P06, P09, P10, P11, P12, P13, P14, P15, P16, P18, P21, P22, P23, P25, P26, P27, P28, P29, P30, P31, P32	Maintain containment boundary

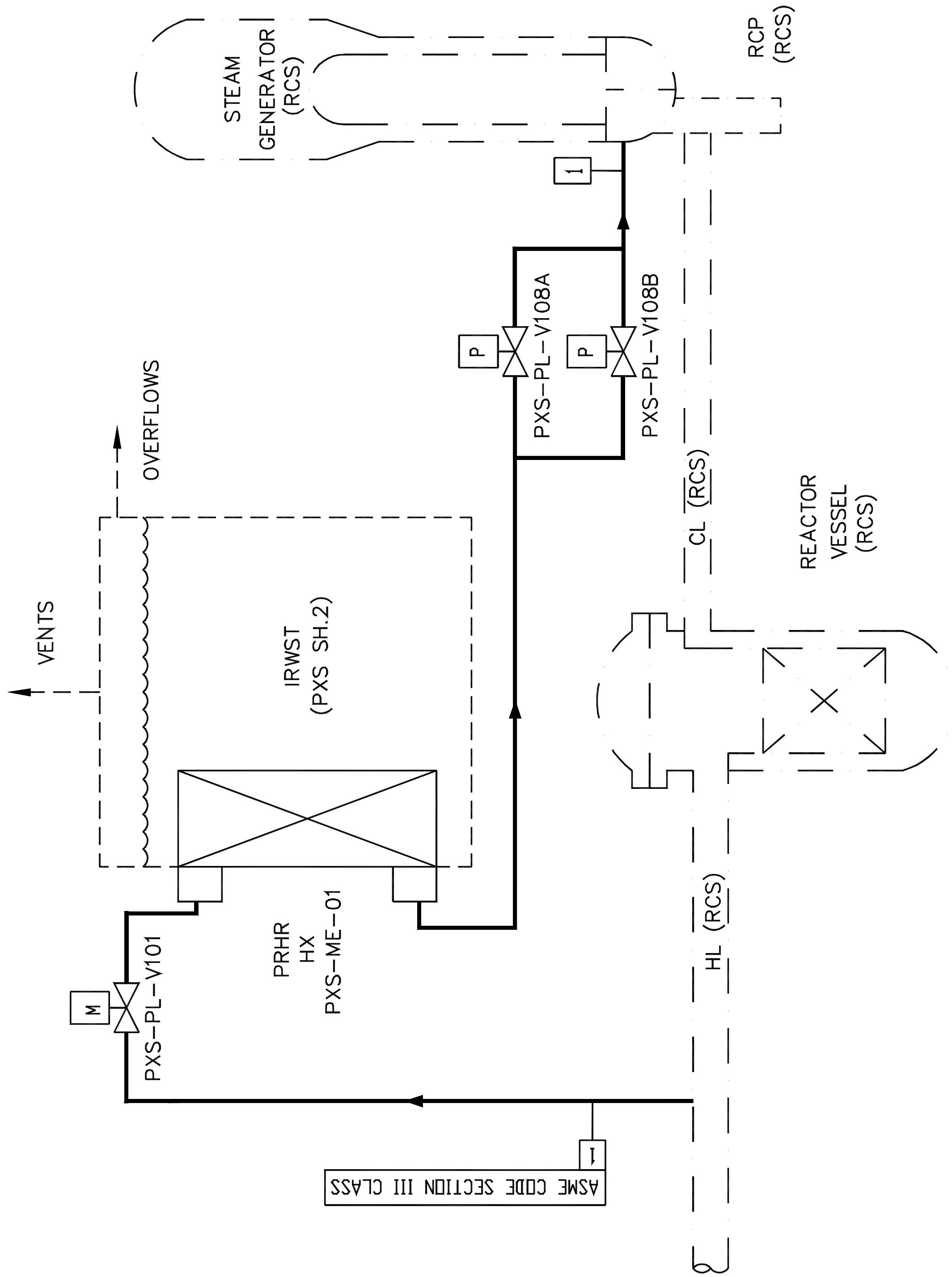


Figure 2.2.3-1 (Sheet 1 of 2)
Passive Core Cooling System

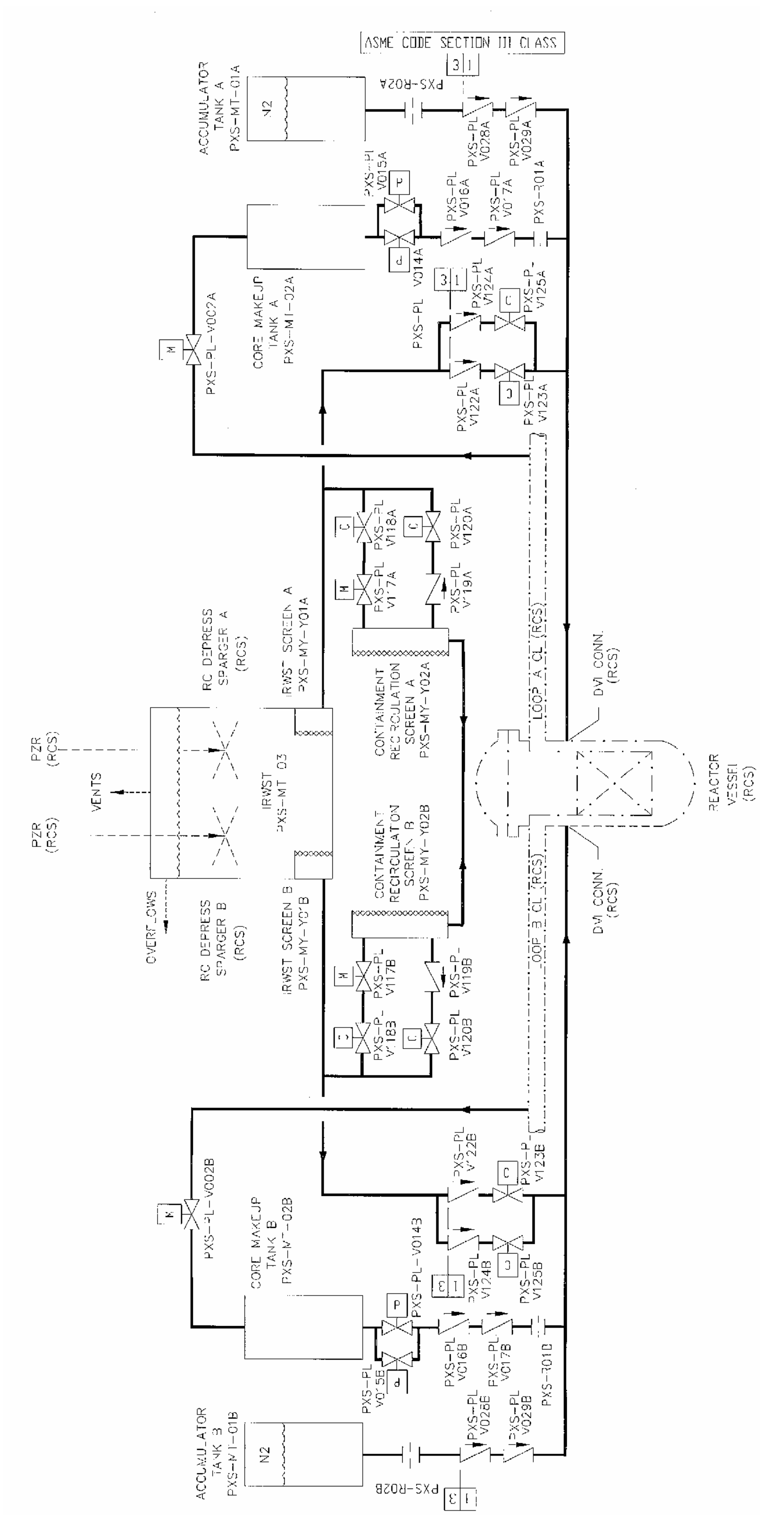


Figure 2.2.3-1 (Sheet 2 of 2)
Passive Core Cooling System

2.2.4 Steam Generator System

Design Description

The steam generator system (SGS) and portions of the main and startup feedwater system (FWS) transport and control feedwater from the condensate system to the steam generators during normal operation. The SGS and portions of the main steam system (MSS) and turbine system (MTS) transport and control steam from the steam generators to the turbine generator during normal operations. These systems also isolate the steam generators from the turbine generator and the condensate system during design basis accidents.

The SGS is as shown in Figure 2.2.4-1, sheets 1 and 2, and portions of the FWS, MSS, and MTS are as shown in Figure 2.2.4-1, sheet 3, and the locations of the components in these systems is as shown in Table 2.2.4-5.

1. The functional arrangement of the SGS and portions of the FWS, MSS, and MTS are as described in the Design Description of this Section 2.2.4.

2. a) The components identified in Table 2.2.4-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.

   b) The piping identified in Table 2.2.4-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.

3. a) Pressure boundary welds in components identified in Table 2.2.4-1 as ASME Code Section III meet ASME Code Section III requirements.

   b) Pressure boundary welds in piping identified in Table 2.2.4-2 as ASME Code Section III meet ASME Code Section III requirements.

4. a) The components identified in Table 2.2.4-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.

   b) The piping identified in Table 2.2.4-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.

5. a) The seismic Category I equipment identified in Table 2.2.4-1 can withstand seismic design basis loads without loss of safety function.

   b) Each of the lines identified in Table 2.2.4-2 for which functional capability is required is designed to withstand combined normal and seismic design basis loads without a loss of its functional capability.

6. Each of the as-built lines identified in Table 2.2.4-2 as designed for leak before break (LBB) meets the LBB criteria, or an evaluation is performed of the protection from the dynamic effects of a rupture of the line.

7. a) The Class 1E equipment identified in Table 2.2.4-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.

   b) The Class 1E components identified in Table 2.2.4-1 are powered from their respective Class 1E division.

   c) Separation is provided between SGS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.

8. The SGS provides the following safety-related functions:

   a) The SGS provides a heat sink for the reactor coolant system (RCS) and provides overpressure protection.

   b) During design basis events, the SGS limits steam generator blowdown and feedwater flow to the steam generator.

   c) The SGS preserves containment integrity by isolation of the SGS lines penetrating the containment. The inside containment isolation function (isolating the RCS and containment atmosphere from the environment) is provided by the steam generator, tubes, and SGS lines inside containment while isolation outside containment is provided by manual and automatic valves.

9. The SGS provides the following nonsafety-related functions:

   a) Components within the main steam system, main and startup feedwater system, and the main turbine system identified in Table 2.2.4-3 provide backup isolation of the SGS to limit steam generator blowdown and feedwater flow to the steam generator.

   b) During shutdown operations, the SGS removes decay heat by delivery of startup feedwater to the steam generator and venting of steam from the steam generators to the atmosphere.

10. Safety-related displays identified in Table 2.2.4-1 can be retrieved in the main control room (MCR).

11. a) Controls exist in the MCR to cause the remotely operated valves identified in Table 2.2.4-1 to perform active functions.

    b) The valves identified in Table 2.2.4-1 as having PMS control perform an active safety function after receiving a signal from PMS.

12. a) The motor-operated valves identified in Table 2.2.4-1 perform an active safety-related function to change position as indicated in the table.

    b) After loss of motive power, the remotely operated valves identified in Table 2.2.4-1 assume the indicated loss of motive power position.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.2.4-4 specifies the inspections, tests, analyses, and associated acceptance criteria for the SGS.

Table 2.2.4-1									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS**	**Active Function**	**Loss of Motive Power Position**
Main Steam Safety Valve SG01	SGS-PL-V030A	Yes	Yes	-	-/-	No	-	Transfer Open/ Transfer Closed	-
Main Steam Safety Valve SG02	SGS-PL-V030B	Yes	Yes	-	-/-	No	-	Transfer Open/ Transfer Closed	-
Main Steam Safety Valve SG01	SGS-PL-V031A	Yes	Yes	-	-/-	No	-	Transfer Open/ Transfer Closed	-
Main Steam Safety Valve SG02	SGS-PL-V031B	Yes	Yes	-	-/-	No	-	Transfer Open/ Transfer Closed	-
Main Steam Safety Valve SG01	SGS-PL-V032A	Yes	Yes	-	-/-	No	-	Transfer Open/ Transfer Closed	-
Main Steam Safety Valve SG02	SGS-PL-V032B	Yes	Yes	-	-/-	No	-	Transfer Open/ Transfer Closed	-

Note: Dash (-) indicates not applicable.

Table 2.2.4-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS**	**Active Function**	**Loss of Motive Power Position**
Main Steam Safety Valve SG01	SGS-PL-V033A	Yes	Yes	-	-/-	No	-	Transfer Open/ Transfer Closed	-
Main Steam Safety Valve SG02	SGS-PL–V033B	Yes	Yes	-	-/-	No	-	Transfer Open/ Transfer Closed	-
Main Steam Safety Valve SG01	SGS-PL–V034A	Yes	Yes	-	-/-	No	-	Transfer Open/ Transfer Closed	-
Main Steam Safety Valve SG02	SGS-PL–V034B	Yes	Yes	-	-/-	No	-	Transfer Open/ Transfer Closed	-
Main Steam Safety Valve SG01	SGS-PL–V035A	Yes	Yes	-	-/-	No	-	Transfer Open/ Transfer Closed	-
Main Steam Safety Valve SG02	SGS-PL–V035B	Yes	Yes	-	-/-	No	-	Transfer Open/ Transfer Closed	-

Note: Dash (-) indicates not applicable.

Table 2.2.4-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS**	**Active Function**	**Loss of Motive Power Position**
Power-operated Relief Valve Block Motor-operated Valve Steam Generator 01	SGS-PL-V027A	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	As Is
Power-operated Relief Valve Block Motor-operated Valve Steam Generator 02	SGS-PL-V027B	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	As Is
Steam Line Condensate Drain Isolation Valve	SGS-PL-V036A	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	Closed
Steam Line Condensate Drain Isolation Valve	SGS-PL-V036B	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	Closed
Main Steam Line Isolation Valve	SGS-PL-V040A	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	As Is
Main Steam Line Isolation Valve	SGS-PL-V040B	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	As Is
Steam Line Condensate Drain Control Valve	SGS-PL-V086A	Yes	Yes	Yes	Yes/Yes	No	Yes	Transfer Closed	Closed
Steam Line Condensate Drain Control Valve	SGS-PL-V086B	Yes	Yes	Yes	Yes/Yes	No	Yes	Transfer Closed	Closed

Table 2.2.4-1 (cont.)

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS	Active Function	Loss of Motive Power Position
Main Feedwater Isolation Valve	SGS-PL-V057A	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	As Is
Main Feedwater Isolation Valve	SGS-PL-V057B	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	As Is
Startup Feedwater Isolation Motor-operated Valve	SGS-PL-V067A	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	As Is
Startup Feedwater Isolation Motor-operated Valve	SGS-PL-V067B	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	As Is
Steam Generator Blowdown Isolation Valve	SGS-PL-V074A	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	Closed
Steam Generator Blowdown Isolation Valve	SGS-PL-V074B	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	Closed
Steam Generator Blowdown Isolation Valve	SGS-PL-V075A	Yes	Yes	Yes	Yes/Yes	No	Yes	Transfer Closed	Closed
Steam Generator Blowdown Isolation Valve	SGS-PL-V075B	Yes	Yes	Yes	Yes/Yes	No	Yes	Transfer Closed	Closed

Table 2.2.4-1 (cont.)

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS	Active Function	Loss of Motive Power Position
Power-operated Relief Valve	SGS-PL-V233A	Yes	Yes	Yes	Yes/Yes	No	Yes	Transfer Closed	Closed
Power-operated Relief Valve	SGS-PL-V233B	Yes	Yes	Yes	Yes/Yes	No	Yes	Transfer Closed	Closed
Main Steam Isolation Valve Bypass Isolation	SGS-PL-V240A	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	Closed
Main Steam Isolation Valve Bypass Isolation	SGS-PL-V240B	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	Closed
Main Feedwater Control Valve	SGS-PL-V250A	Yes	Yes	Yes	Yes/Yes	No	Yes	Transfer Closed	Closed
Main Feedwater Control Valve	SGS-PL-V250B	Yes	Yes	Yes	Yes/Yes	No	Yes	Transfer Closed	Closed
Startup Feedwater Control Valve	SGS-PL-V255A	Yes	Yes	Yes	Yes/Yes	No	Yes	Transfer Closed	Closed
Startup Feedwater Control Valve	SGS-PL-V255B	Yes	Yes	Yes	Yes/Yes	No	Yes	Transfer Closed	Closed

Table 2.2.4-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS**	**Active Function**	**Loss of Motive Power Position**
Steam Generator 1 Narrow Range Level Sensor	SGS-001	No	Yes	-	Yes/Yes	Yes	-	-	-
Steam Generator 1 Narrow Range Level Sensor	SGS–002	No	Yes	-	Yes/Yes	Yes	-	-	-
Steam Generator 1 Narrow Range Level Sensor	SGS–003	No	Yes	-	Yes/Yes	Yes	-	-	-
Steam Generator 1 Narrow Range Level Sensor	SGS–004	No	Yes	-	Yes/Yes	Yes	-	-	-
Steam Generator 2 Narrow Range Level Sensor	SGS–005	No	Yes	-	Yes/Yes	Yes	-	-	-
Steam Generator 2 Narrow Range Level Sensor	SGS–006	No	Yes	-	Yes/Yes	Yes	-	-	-
Steam Generator 2 Narrow Range Level Sensor	SGS–007	No	Yes	-	Yes/Yes	Yes	-	-	-

Note: Dash (-) indicates not applicable.

Table 2.2.4-1 (cont.)

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS	Active Function	Loss of Motive Power Position
Steam Generator 2 Narrow Range Level Sensor	SGS-008	No	Yes	-	Yes/Yes	Yes	-	-	-
Steam Generator 1 Wide Range Level Sensor	SGS-011	No	Yes	-	Yes/Yes	Yes	-	-	-
Steam Generator 1 Wide Range Level Sensor	SGS-012	No	Yes	-	Yes/Yes	Yes	-	-	-
Steam Generator 2 Wide Range Level Sensor	SGS-013	No	Yes	-	Yes/Yes	Yes	-	-	-
Steam Generator 2 Wide Range Level Sensor	SGS-014	No	Yes	-	Yes/Yes	Yes	-	-	-
Steam Generator 1 Wide Range Level Sensor	SGS-015	No	Yes	-	Yes/Yes	Yes	-	-	-
Steam Generator 1 Wide Range Level Sensor	SGS-016	No	Yes	-	Yes/Yes	Yes	-	-	-
Steam Generator 2 Wide Range Level Sensor	SGS-017	No	Yes	-	Yes/Yes	Yes	-	-	-

Note: Dash (-) indicates not applicable.

Table 2.2.4-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS**	**Active Function**	**Loss of Motive Power Position**
Steam Generator 2 Wide Range Level Sensor	SGS-018	No	Yes	-	Yes/Yes	Yes	-	-	-
Main Steam Line Steam Generator 1 Pressure Sensor	SGS-030	No	Yes	-	Yes/Yes	Yes	-	-	-
Main Steam Line Steam Generator 1 Pressure Sensor	SGS-031	No	Yes	-	Yes/Yes	Yes	-	-	-
Main Steam Line Steam Generator 1 Pressure Sensor	SGS-032	No	Yes	-	Yes/Yes	Yes	-	-	-
Main Steam Line Steam Generator 1 Pressure Sensor	SGS-033	No	Yes	-	Yes/Yes	Yes	-	-	-
Main Steam Line Steam Generator 2 Pressure Sensor	SGS-034	No	Yes	-	Yes/Yes	Yes	-	-	-
Main Steam Line Steam Generator 2 Pressure Sensor	SGS-035	No	Yes	-	Yes/Yes	Yes	-	-	-
Main Steam Line Steam Generator 2 Pressure Sensor	SGS-036	No	Yes	-	Yes/Yes	Yes	-	-	-

Note: Dash (-) indicates not applicable.

Table 2.2.4-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS**	**Active Function**	**Loss of Motive Power Position**
Main Steam Line Steam Generator 2 Pressure Sensor	SGS-037	No	Yes	-	Yes/Yes	Yes	-	-	-
Steam Generator 1 Startup Feedwater Flow Sensor	SGS-55A	No	Yes	-	Yes/Yes	Yes	-	-	-
Steam Generator 1 Startup Feedwater Flow Sensor	SGS-55B	No	Yes	-	Yes/Yes	Yes	-	-	-
Steam Generator 2 Startup Feedwater Flow Sensor	SGS-56A	No	Yes	-	Yes/Yes	Yes	-	-	-
Steam Generator 2 Startup Feedwater Flow Sensor	SGS-56B	No	Yes	-	Yes/Yes	Yes	-	-	-

Note: Dash (-) indicates not applicable.

Table 2.2.4-2				
Line Name	**Line Number**	**ASME Code Section III**	**Leak Before Break**	**Functional Capability Required**
Main Feedwater Line	SGS-PL-L002A, L002B	Yes	No	No
Main Feedwater Line	SGS-PL-L003A, L003B	Yes	No	No
Startup Feedwater Line	SGS-PL-L004A, L004B	Yes	No	No
Startup Feedwater Line	SGS-PL-L005A, L005B	Yes	No	No
Main Steam Line (within containment)	SGS-PL-L006A, L006B	Yes	Yes	Yes
Main Steam Line (outside of containment)	SGS-PL-L006A, L006B	Yes	No	Yes
Main Steam Line	SGS-PL-L007A, L007B	Yes	No	No
Safety Valve Inlet Line	SGS-PL-L015A, L015B, L015C, L015D, L015E, L015F, L015G, L015H, L015J, L015K, L015L, L015M	Yes	No	Yes
Safety Valve Discharge Line	SGS-PL-L018A, L018B, L018C, L018D, L018E, L018F, L018G, L018H, L018J, L018K, L018L, L018M	Yes	No	Yes
Power-operated Relief Block Valve Inlet Line	SGS-PL-L024A, L024B	Yes	No	No
Power-operated Relief Valve Inlet Line	SGS-PL-L014A, L014B	Yes	No	No

Note: Dash (-) indicates not applicable.

Table 2.2.4-2				
Line Name	**Line Number**	**ASME Code Section III**	**Leak Before Break**	**Functional Capability Required**
Main Steam Isolation Valve Bypass Inlet Line	SGS-PL-L022A, L022B	Yes	No	No
Main Steam Isolation Valve Bypass Outlet Line	SGS-PL-L023A, L023B	Yes	No	No
Main Steam Condensate Drain Line	SGS-PL-L021A, L021B	Yes	No	No
Steam Generator Blowdown Line	SGS-PL-L009A, L009B	Yes	No	No
Steam Generator Blowdown Line	SGS-PL-L027A, L027B	Yes	No	No
Steam Generator Blowdown Line	SGS-PL-L010A, L010B	Yes	No	No

Note: Dash (-) indicates not applicable.

Table 2.2.4-3		
Equipment Name	**Tag No.**	**Control Function**
Turbine Stop Valve	MTS-PL-V001A	Close
Turbine Stop Valve	MTS-PL-V001B	Close
Turbine Control Valve	MTS-PL-V002A	Close
Turbine Control Valve	MTS-PL-V002B	Close
Turbine Stop Valve	MTS-PL-V003A	Close
Turbine Stop Valve	MTS-PL-V003B	Close
Turbine Control Valve	MTS-PL-V004A	Close
Turbine Control Valve	MTS-PL-V004B	Close
Turbine Bypass Control Valve	MSS-PL-V001	Close
Turbine Bypass Control Valve	MSS-PL-V002	Close
Turbine Bypass Control Valve	MSS-PL-V003	Close
Turbine Bypass Control Valve	MSS-PL-V004	Close
Turbine Bypass Control Valve	MSS-PL-V005	Close
Turbine Bypass Control Valve	MSS-PL-V006	Close
Moisture Separator Stage 1 Reheat Supply Steam Control Valve	MSS-PL-V016A	Close
Moisture Separator Stage 1 Reheat Supply Steam Control Valve	MSS-PL-V016B	Close
Moisture Separator Stage 2 Reheat Supply Steam Control Valve	MSS-PL-V017A	Close
Moisture Separator Stage 2 Reheat Supply Steam Control Valve	MSS-PL-V017B	Close
Main to Startup Feedwater Crossover Valve	FWS-PL-097	Close
Main Feedwater Pump	FWS-MP-02A	Trip
Main Feedwater Pump	FWS-MP-02B	Trip
Main Feedwater Pump	FWS-MP-02C	Trip
Startup Feedwater Pump	FWS-MP-03A	Trip
Startup Feedwater Pump	FWS-MP-03B	Trip

Table 2.2.4-4
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the SGS and portions of the FWS, MSS, and MTS are as described in the Design Description of this Section 2.2.4.	Inspection of the as-built system will be performed.	The as-built SGS and portions of the FWS, MSS, and MTS conform with the functional arrangement as defined in the Design Description of this Section 2.2.4.
2.a) The components identified in Table 2.2.4-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built components as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built components identified in Table 2.2.4-1 as ASME Code Section III.
2.b) The piping identified in Table 2.2.4-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built piping as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built piping identified in Table 2.2.4-2 as ASME Code Section III.
3.a) Pressure boundary welds in components identified in Table 2.2.4-1 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
3.b) Pressure boundary welds in piping identified in Table 2.2.4-2 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.

Table 2.2.4-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4.a) The components identified in Table 2.2.4-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.	A hydrostatic test will be performed on the components required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the components identified in Table 2.2.4-1 as ASME Code Section III conform with the requirements of the ASME Code Section III.
4.b) The piping identified in Table 2.2.4-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.	A hydrostatic test will be performed on the piping required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the piping identified in Table 2.2.4-2 as ASME Code Section III conform with the requirements of the ASME Code Section III.
5.a) The seismic Category I equipment identified in Table 2.2.4-1 can withstand seismic design basis loads without loss of safety function.	i) Inspection will be performed to verify that the seismic Category I equipment identified in Table 2.2.4-1 is located on the Nuclear Island.	i) The seismic Category I equipment identified in Table 2.2.4-1 is located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis loads without loss of safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) A report exists and concludes that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.
5.b) Each of the lines identified in Table 2.2.4-2 for which functional capability is required is designed to withstand combined normal and seismic design basis loads without a loss of its functional capability.	Inspection will be performed for the existence of a report concluding that the as-built piping meets the requirements for functional capability.	A report exists and concludes that each of the as-built lines identified in Table 2.2.4-2 for which functional capability is required meets the requirements for functional capability.

Table 2.2.4-4 (cont.) Inspections, Tests, Analyses, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
6. Each of the as-built lines identified in Table 2.2.4-2 as designed for LBB meets the LBB criteria, or an evaluation is performed of the protection from the dynamic effects of a rupture of the line.	Inspection will be performed for the existence of an LBB evaluation report or an evaluation report on the protection from effects of a pipe break. Tier 1 Material, Section 3.3, Nuclear Island Buildings, contains the design descriptions and inspections, tests, analyses, and acceptance criteria for protection from the dynamic effects of pipe rupture.	An LBB evaluation report exists and concludes that the LBB acceptance criteria are met by the as-built RCS piping and piping materials, or a pipe break evaluation report exists and concludes that protection from the dynamic effects of a line break is provided.
7.a) The Class 1E equipment identified in Table 2.2.4-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.	i) Type tests, analyses, or a combination of type tests and analyses will be performed on Class 1E equipment located in a harsh environment. ii) Inspection will be performed of the as-installed Class 1E equipment and the associated wiring, cables, and terminations located in a harsh environment.	i) A report exists and concludes that the Class 1E equipment identified in Table 2.2.4-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function. ii) A report exists and concludes that the as-installed Class 1E equipment and the associated wiring, cables, and terminations identified in Table 2.2.4-1 as being qualified for a harsh environment are bounded by type tests, analyses, or a combination of type tests and analyses.
7.b) The Class 1E components identified in Table 2.2.4-1 are powered from their respective Class 1E division.	Testing will be performed by providing a simulated test signal in each Class 1E division.	A simulated test signal exists at the Class 1E equipment identified in Table 2.2.4-1 when the assigned Class 1E division is provided the test signal.
7.c) Separation is provided between SGS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.	See Tier 1 Material, Table 3.3-6, item 7.d.	See Tier 1 Material, Table 3.3-6, item 7.d.

Table 2.2.4-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
8.a) The SGS provides a heat sink for the RCS and provides overpressure protection in accordance with Section III of the ASME Boiler and Pressure Vessel Code.	i) Inspections will be conducted to confirm that the value of the vendor code plate rating of the steam generator safety valves is greater than or equal to system relief requirements. ii) Testing and analyses in accordance with ASME Code Section III will be performed to determine set pressure.	i) The sum of the rated capacities recorded on the valve vendor code plates of the steam generator safety valves exceeds 8,340,000 lb/hr per steam generator. ii) A report exists to indicate the set pressure of the valves is less than 1305 psig.
8.b) During design basis events, the SGS limits steam generator blowdown and feedwater flow to the steam generator.	i) Testing will be performed to confirm isolation of the main feedwater, startup feedwater, blowdown, and main steam lines. See item 11 in this table. ii) Inspection will be performed for the existence of a report confirming that the area of the flow limiting orifice within the SG main steam outlet nozzle will limit releases to the containment.	See item 11 in this table. ii) A report exists to indicate the installed flow limiting orifice within the SG main steam line discharge nozzle does not exceed 1.4 sq. ft.
8.c) The SGS preserves containment integrity by isolation of the SGS lines penetrating the containment.	See Tier 1 Material, Table 2.2.1-3, item 7.	See Tier 1 Material, Table 2.2.1-3, item 7.
9.a) Components within the main steam system, main and startup feedwater system, and the main turbine system identified in Table 2.2.4-3 provide backup isolation of the SGS to limit steam generator blowdown and feedwater flow to the steam generator.	i) Testing will be performed to confirm closure of the valves identified in Table 2.2.4-3. ii) Testing will be performed to confirm the trip of the pumps identified in Table 2.2.4-3.	i) The valves identified in Table 2.2.4-3 close after a signal is generated by the PMS. ii) The pumps identified in Table 2.2.4-3 trip after a signal is generated by the PMS.

Table 2.2.4-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9.b) During shutdown operations, the SGS removes decay heat by delivery of startup feedwater to the steam generator and venting of steam from the steam generators to the atmosphere.	i) Tests will be performed to demonstrate the ability of the startup feedwater system to provide feedwater to the steam generators. ii) Tests and/or analyses will be performed to demonstrate the ability of the power-operated relief valves to discharge steam from the steam generators to the atmosphere.	i) See Tier 1 Material, subsection 2.4.1, Main and Startup Feedwater System. ii) A report exists and concludes that each power-operated relief valve will relieve greater than 300,000 lb/hr at 1106 psia ±10 psi.
10. Safety-related displays identified in Table 2.2.4-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the safety-related displays in the MCR.	Safety-related displays identified in Table 2.2.4-1 can be retrieved in the MCR.
11.a) Controls exist in the MCR to cause the remotely operated valves identified in Table 2.2.4-1 to perform active functions.	Stroke testing will be performed on the remotely operated valves listed in Table 2.2.4-1 using controls in the MCR.	Controls in the MCR operate to cause the remotely operated valves to perform active safety functions.
11.b) The valves identified in Table 2.2.4-1 as having PMS control perform an active safety function after receiving a signal from PMS.	i) Testing will be performed on the remotely operated valves listed in Table 2.2.4-1 using real or simulated signals into the PMS. ii) Testing will be performed to demonstrate that remotely operated SGS isolation valves SGS-V027A/B, V040A/B, V057A/B, V250A/B close within the required response times.	i) The remotely-operated valves identified in Table 2.2.4-1 as having PMS control perform the active function identified in the table after receiving a signal from the PMS. ii) These valves close within the following times after receipt of an actuation signal: V027A/B < 44 sec V040A/B, V057A/B < 5 sec V250A/B < 5 sec

Table 2.2.4-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
12.a) The motor-operated valves identified in Table 2.2.4-1 perform an active safety-related function to change position as indicated in the table.	i) Tests or type tests of motor-operated valves will be performed to demonstrate the capability of the valve to operate under its design conditions.	i) A test report exists and concludes that each motor-operated valve changes position as indicated in Table 2.2.4-1 under design conditions.
	ii) Inspection will be performed for the existence of a report verifying that the as-installed motor-operated valves are bounded by the tests or type tests.	ii) A report exists and concludes that the as-installed motor-operated valves are bounded by the tests or type tests.
	iii) Tests of the as-installed motor-operated valves will be performed under pre-operational flow, differential pressure, and temperature conditions.	iii) Each motor-operated valve changes position as indicated in Table 2.2.4-1 under pre-operational test conditions.
12.b) After loss of motive power, the remotely operated valves identified in Table 2.2.4-1 assume the indicated loss of motive power position.	Testing of the installed valves will be performed under the conditions of loss of motive power.	After loss of motive power, each remotely operated valve identified in Table 2.2.4-1 assumes the indicated loss of motive power position.

Table 2.2.4-5		
Component Name	**Tag No.**	**Component Location**
Main Steam Line Isolation Valve	SGS-PL-V040A	Auxiliary Building
Main Steam Line Isolation Valve	SGS-PL-V040B	Auxiliary Building
Main Feedwater Isolation Valve	SGS-PL-V057A	Auxiliary Building
Main Feedwater Isolation Valve	SGS-PL-V057B	Auxiliary Building
Main Feedwater Control Valve	SGS-PL-V250A	Auxiliary Building
Main Feedwater Control Valve	SGS-PL-V250B	Auxiliary Building
Turbine Stop Valves	MTS-PL-V001A MTS-PL-V001B MTS-PL-V003A MTS-PL-V003B	Turbine Building
Turbine Control Valves	MTS-PL-V002A MTS-PL-V002B MTS-PL-V004A MTS-PL-V004B	Turbine Building
Main Feedwater Pumps	FWS-MP-02A FWS-MP-02B FWS-MP-02C	Turbine Building
Feedwater Booster Pumps	FWS-MP-01A FWS-MP-01B FWS-MP-01C	Turbine Building

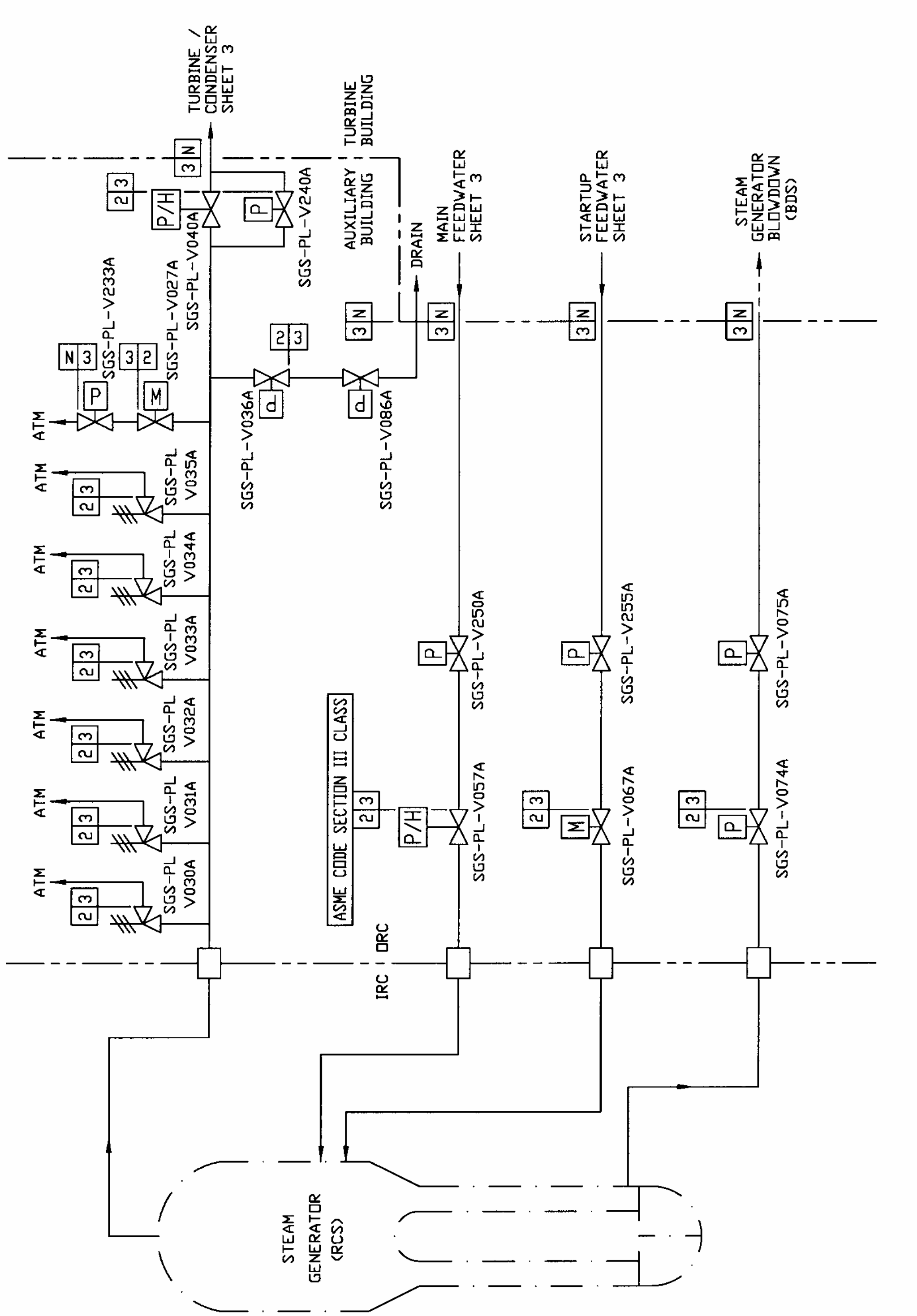


Figure 2.2.4-1 (Sheet 1 of 3)
Steam Generator System

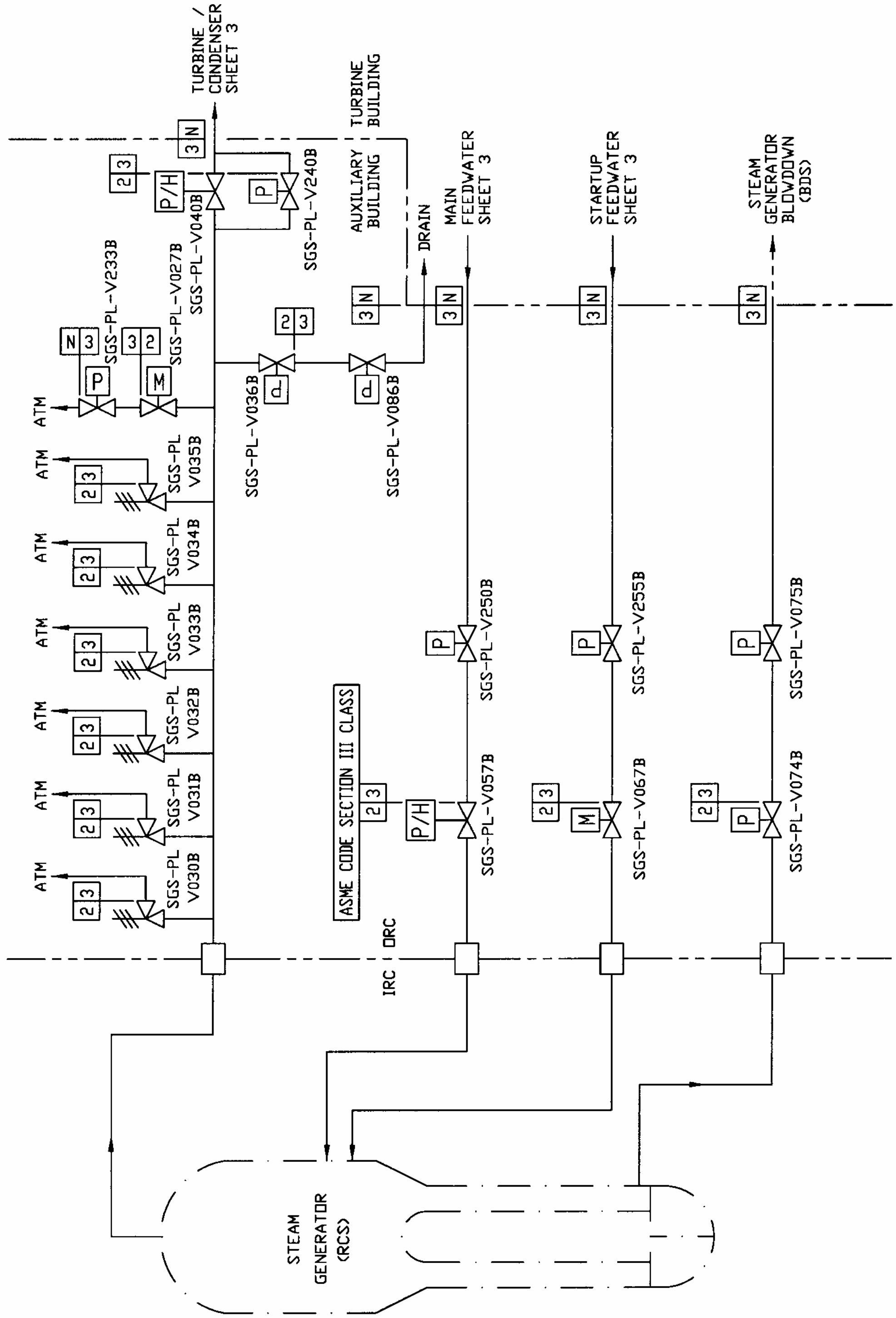


Figure 2.2.4-1 (Sheet 2 of 3)
Steam Generator System

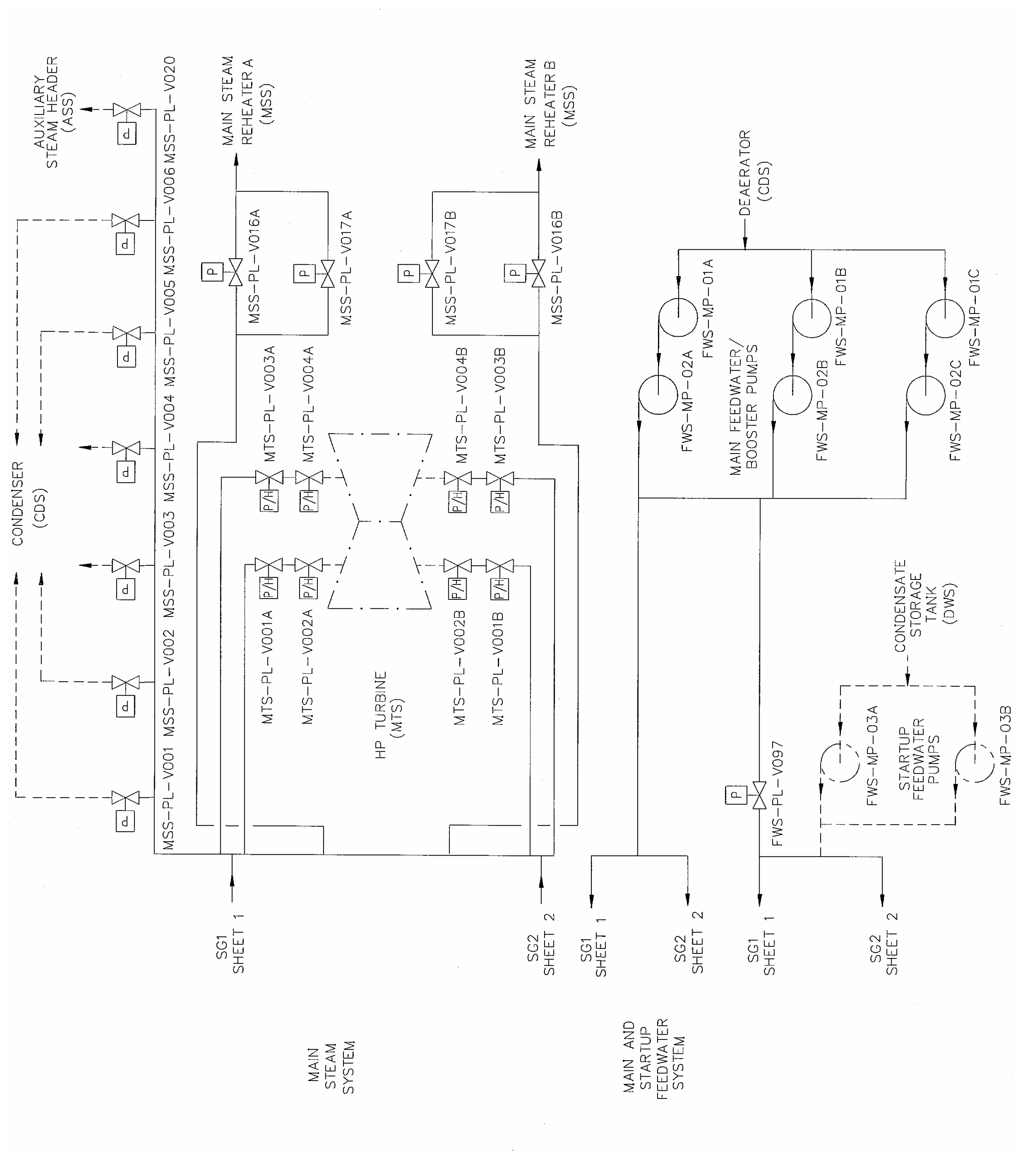


Figure 2.2.4-1 (Sheet 3 of 3)
Steam Generator System

2.2.5 Main Control Room Emergency Habitability System

Design Description

The main control room emergency habitability system (VES) provides a supply of breathable air for the main control room (MCR) occupants and maintains the MCR at a positive pressure with respect to the surrounding areas whenever ac power is not available to operate the nuclear island nonradioactive ventilation system (VBS) or high radioactivity is detected in the MCR air supply. (See Tier 1 material, Section 3.5 for Radiation Monitoring). The VES also limits the heatup of the MCR, the 1E instrumentation and control (I&C) equipment rooms, and the Class 1E dc equipment rooms by using the heat capacity of surrounding structures.

The VES is as shown in Figure 2.2.5-1 and the component locations of the VES are as shown in Table 2.2.5-6.

1. The functional arrangement of the VES is as described in the Design Description of this Section 2.2.5.

2. a) The components identified in Table 2.2.5-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.

   b) The piping identified in Table 2.2.5-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.

3. a) Pressure boundary welds in components identified in Table 2.2.5-1 as ASME Code Section III meet ASME Code Section III requirements.

   b) Pressure boundary welds in piping identified in Table 2.2.5-2 as ASME Code Section III meet ASME Code Section III requirements.

4. a) The components identified in Table 2.2.5-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.

   b) The piping identified in Table 2.2.5-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.

5. a) The seismic Category I equipment identified in Table 2.2.5-1 can withstand seismic design basis loads without loss of safety function.

   b) Each of the lines identified in Table 2.2.5-2 for which functional capability is required is designed to withstand combined normal and seismic design basis loads without a loss of its functional capability.

6. a) The Class 1E components identified in Table 2.2.5-1 are powered from their respective Class 1E division.

   b) Separation is provided between VES Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.

7. The VES provides the following safety-related functions:

    a) The VES provides a 72-hour supply of breathable quality air for the occupants of the MCR.

    b) The VES maintains the MCR pressure boundary at a positive pressure with respect to the surrounding areas.

    c) The heat loads within the MCR, the I&C equipment rooms, and the Class 1E dc equipment rooms are within design basis assumptions to limit the heatup of the rooms identified in Table 2.2.5-4.

8. Safety-related displays identified in Table 2.2.5-1 can be retrieved in the MCR.

9. a) Controls exist in the MCR to cause those remotely operated valves identified in Table 2.2.5-1 to perform their active functions.

    b) The valves identified in Table 2.2.5-1 as having protection and safety monitoring system (PMS) control perform their active safety function after receiving a signal from the PMS.

10. After loss of motive power, the remotely operated valves identified in Table 2.2.5-1 assume the indicated loss of motive power position.

11. Displays of the parameters identified in Table 2.2.5-3 can be retrieved in the MCR.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.2.5-4 specifies the inspections, tests, analyses, and associated acceptance criteria for the VES.

Table 2.2.5-1									
Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS	Active Function	Loss of Motive Power Position
Emergency Air Storage Tank 01	VES-MT-01	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 02	VES-MT-02	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 03	VES-MT-03	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 04	VES-MT-04	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 05	VES-MT-05	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 06	VES-MT-06	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 07	VES-MT-07	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 08	VES-MT-08	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 09	VES-MT-09	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 10	VES-MT-10	No	Yes	-	-/-	-	-	-	-

Note: Dash (-) indicates not applicable.

Table 2.2.5-1 (cont.)

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS	Active Function	Loss of Motive Power Position
Emergency Air Storage Tank 11	VES-MT-11	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 12	VES-MT-12	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 13	VES-MT-13	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 14	VES-MT-14	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 15	VES-MT-15	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 16	VES-MT-16	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 17	VES-MT-17	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 18	VES-MT-18	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 19	VES-MT-19	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 20	VES-MT-20	No	Yes	-	-/-	-	-	-	-

Note: Dash (-) indicates not applicable.

Table 2.2.5-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS**	**Active Function**	**Loss of Motive Power Position**
Emergency Air Storage Tank 21	VES-MT-21	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 22	VES-MT-22	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 23	VES-MT-23	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 24	VES-MT-24	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 25	VES-MT-25	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 26	VES-MT-26	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 27	VES-MT-27	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 28	VES-MT-28	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 29	VES-MT-29	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 30	VES-MT-30	No	Yes	-	-/-	-	-	-	-

Note: Dash (-) indicates not applicable.

Table 2.2.5-1 (cont.)

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS	Active Function	Loss of Motive Power Position
Emergency Air Storage Tank 31	VES-MT-31	No	Yes	-	-/-	-	-	-	-
Emergency Air Storage Tank 32	VES-MT-32	No	Yes	-	-/-	-	-	-	-
Pressure Regulating Valve A	VES-PL-V002A	Yes	Yes	No	-/-	No	-	Throttle Flow	-
Pressure Regulating Valve B	VES-PL-V002B	Yes	Yes	No	-/-	No	-	Throttle Flow	-
MCR Air Delivery Isolation Valve A	VES-PL-V005A	Yes	Yes	Yes	Yes/No	No	Yes	Transfer Open	Open
MCR Air Delivery Isolation Valve B	VES-PL-V005B	Yes	Yes	Yes	Yes/No	No	Yes	Transfer Open	Open
MCR Pressure Relief Isolation Valve A	VES-PL-V022A	Yes	Yes	Yes	Yes/No	No	Yes	Transfer Open/ Transfer Closed	Open
MCR Pressure Relief Isolation Valve B	VES-PL-V022B	Yes	Yes	Yes	Yes/No	No	Yes	Transfer Open/ Transfer Closed	Open
MCR Air Delivery Line Flow Sensor	VES-003A	No	Yes	-	Yes/No	Yes	-	-	-

Note: Dash (-) indicates not applicable.

Table 2.2.5-1 (cont.)

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS	Active Function	Loss of Motive Power Position
MCR Air Delivery Line Flow Sensor	VES-003B	No	Yes	-	Yes/No	Yes	-	-	-
MCR Differential Pressure Sensor A	VES-004A	No	Yes	-	Yes/No	Yes	-	-	-
MCR Differential Pressure Sensor B	VES-004B	No	Yes	-	Yes/No	Yes	-	-	-

Note: Dash (-) indicates not applicable.

Table 2.2.5-2			
Line Name	Line Number	ASME Code Section III	Functional Capability Required
MCR Relief Line	VES-PL-022A	Yes	Yes
MCR Relief Line	VES-PL-022B	Yes	Yes

Table 2.2.5-3		
Equipment	Tag No.	Display
Air Storage Tank Pressure	VES-001A	Yes
Air Storage Tank Pressure	VES-001B	Yes

Table 2.2.5-4			
Room Name	Room Numbers	Heat Load 0 to 24 Hours (Btu/s)	Heat Load 24 to 72 Hours (Btu/s)
MCR Envelope	12401	12.8 (hour 0 through 3) 5.1 (hour 4 through 24)	3.9
I&C Rooms	12301, 12305	8.8	0
I&C Rooms	12302, 12304	13.0	4.2
dc Equipment Rooms	12201, 12205	3.7 (hour 0 through 1) 2.4 (hour 2 through 24)	0
dc Equipment Rooms	12203, 12207	5.8 (hour 0 through 1) 4.5 (hour 2 through 24)	2.0

Table 2.2.5-5 Inspections, Tests, Analyses, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The functional arrangement of the VES is as described in the Design Description of this Section 2.2.5.	Inspection of the as-built system will be performed.	The as-built VES conforms with the functional arrangement described in the Design Description of this Section 2.2.5.
2.a) The components identified in Table 2.2.5-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built components as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built components identified in Table 2.2.5-1 as ASME Code Section III.
2.b) The piping identified in Table 2.2.5-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built piping as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built piping identified in Table 2.2.5-2 as ASME Code Section III.
3.a) Pressure boundary welds in components identified in Table 2.2.5-1 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
3.b) Pressure boundary welds in piping identified in Table 2.2.5-2 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
4.a) The components identified in Table 2.2.5-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.	A hydrostatic test will be performed on the components required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the components identified in Table 2.2.5-1 as ASME Code Section III conform with the requirements of the ASME Code Section III.
4.b) The piping identified in Table 2.2.5-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.	A hydrostatic test will be performed on the piping required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the piping identified in Table 2.2.5-2 as ASME Code Section III conform with the requirements of the ASME Code Section III.

Table 2.2.5-5 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5.a) The seismic Category I equipment identified in Table 2.2.5-1 can withstand seismic design basis loads without loss of safety function.	i) Inspection will be performed to verify that the seismic Category I equipment and valves identified in Table 2.2.5-1 are located on the Nuclear Island.	i) The seismic Category I equipment identified in Table 2.2.5-1 is located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis loads without loss of safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) A report exists and concludes that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.
5.b) Each of the lines identified in Table 2.2.5-2 for which functional capability is required is designed to withstand combined normal and seismic design basis loads without a loss of its functional capability.	Inspection will be performed for the existence of a report verifying that the as-built piping meets the requirements for functional capability.	A report exists and concludes that each of the as-built lines identified in Table 2.2.5-2 for which functional capability is required meets the requirements for functional capability.
6.a) The Class 1E components identified in Table 2.2.5-1 are powered from their respective Class 1E division.	Testing will be performed by providing a simulated test signal in each Class 1E division.	A simulated test signal exists at the Class 1E equipment identified in Table 2.2.5-1 when the assigned Class 1E division is provided the test signal.
6.b) Separation is provided between VES Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.	See Tier 1 Material, Table 3.3-6, item 7.d.	See Tier 1 Material, Table 3.3-6, item 7.d.

Table 2.2.5-5 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7.a) The VES provides a 72-hour supply of breathable quality air for the occupants of the MCR.	i) Testing will be performed to confirm that the required amount of air flow is delivered to the MCR.	i) The air flow rate from the VES is at least 60 scfm and not more than 70 scfm.
	ii) Analysis of storage capacity will be performed based on as-built manufacturers data.	ii) The calculated storage capacity is greater than or equal to 314,132 scf.
	iii) MCR air samples will be taken during VES testing and analyzed for quality.	iii) The MCR air is of breathable quality.
7.b) The VES maintains the MCR pressure boundary at a positive pressure with respect to the surrounding areas.	i) Testing will be performed with VES flowrate between 60 and 70 scfm to confirm that the MCR is capable of maintaining the required pressurization of the pressure boundary.	i) The MCR pressure boundary is pressurized to greater than or equal to 1/8-in. water gauge with respect to the surrounding area.
	ii) Air leakage into the MCR will be measured during VES testing using a tracer gas.	ii) Analysis of air leakage measurements indicate that VES operation limits MCR air infiltration consistent with operator dose analysis.
7.c) The heat loads within the MCR, the I&C equipment rooms, and the Class 1E dc equipment rooms are within design basis assumptions to limit the heatup of the rooms identified in Table 2.2.5-4.	An analysis will be performed to determine that the heat loads from as-built equipment within the rooms identified in Table 2.2.5-4 are less than or equal to the design basis assumptions.	A report exists and concludes that: the heat loads within rooms identified in Table 2.2.5-4 are less than or equal to the specified values or that an analysis report exists that concludes: – The temperature and humidity in the MCR remain within limits for reliable human performance for the 72-hour period. – The maximum temperature for the 72-hour period for the I&C rooms is less than or equal to 120°F. – The maximum temperature for the 72-hour period for the Class 1E dc equipment rooms is less than or equal to 120°F.

Table 2.2.5-5 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
8. Safety-related displays identified in Table 2.2.5-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the safety-related displays in the MCR.	Safety-related displays identified in Table 2.2.5-1 can be retrieved in the MCR.
9.a) Controls exist in the MCR to cause remotely operated valves identified in Table 2.2.5-1 to perform their active functions.	Stroke testing will be performed on remotely operated valves identified in Table 2.2.5-1 using the controls in the MCR.	Controls in the MCR operate to cause remotely operated valves identified in Table 2.2.5-1 to perform their active safety functions.
9.b) The valves identified in Table 2.2.5-1 as having PMS control perform their active safety function after receiving a signal from the PMS.	Testing will be performed on remotely operated valves listed in Table 2.2.5-1 using real or simulated signals into the PMS.	The remotely operated valves identified in Table 2.2.5-1 as having PMS control perform the active safety function identified in the table after receiving a signal from the PMS.
10. After loss of motive power, the remotely operated valves identified in Table 2.2.5-1 assume the indicated loss of motive power position.	Testing of the installed valves will be performed under the conditions of loss of motive power.	After loss of motive power, each remotely operated valve identified in Table 2.2.5-1 assumes the indicated loss of motive power position.
11. Displays of the parameters identified in Table 2.2.5-3 can be retrieved in the MCR.	Inspection will be performed for retrievability of the parameters in the MCR.	The displays identified in Table 2.2.5-3 can be retrieved in the MCR.

Table 2.2.5-6		
Component Name	**Tag Number**	**Component Location**
Emergency Air Storage Tank 01	VES-MT-01	Auxiliary Building
Emergency Air Storage Tank 02	VES-MT-02	Auxiliary Building
Emergency Air Storage Tank 03	VES-MT-03	Auxiliary Building
Emergency Air Storage Tank 04	VES-MT-04	Auxiliary Building
Emergency Air Storage Tank 05	VES-MT-05	Auxiliary Building
Emergency Air Storage Tank 06	VES-MT-06	Auxiliary Building
Emergency Air Storage Tank 07	VES-MT-07	Auxiliary Building
Emergency Air Storage Tank 08	VES-MT-08	Auxiliary Building
Emergency Air Storage Tank 09	VES-MT-09	Auxiliary Building
Emergency Air Storage Tank 10	VES-MT-10	Auxiliary Building
Emergency Air Storage Tank 11	VES-MT-11	Auxiliary Building
Emergency Air Storage Tank 12	VES-MT-12	Auxiliary Building
Emergency Air Storage Tank 13	VES-MT-13	Auxiliary Building
Emergency Air Storage Tank 14	VES-MT-14	Auxiliary Building
Emergency Air Storage Tank 15	VES-MT-15	Auxiliary Building
Emergency Air Storage Tank 16	VES-MT-16	Auxiliary Building
Emergency Air Storage Tank 17	VES-MT-17	Auxiliary Building
Emergency Air Storage Tank 18	VES-MT-18	Auxiliary Building
Emergency Air Storage Tank 19	VES-MT-19	Auxiliary Building
Emergency Air Storage Tank 20	VES-MT-20	Auxiliary Building
Emergency Air Storage Tank 21	VES-MT-21	Auxiliary Building
Emergency Air Storage Tank 22	VES-MT-22	Auxiliary Building
Emergency Air Storage Tank 23	VES-MT-23	Auxiliary Building
Emergency Air Storage Tank 24	VES-MT-24	Auxiliary Building
Emergency Air Storage Tank 25	VES-MT-25	Auxiliary Building
Emergency Air Storage Tank 26	VES-MT-26	Auxiliary Building
Emergency Air Storage Tank 27	VES-MT-27	Auxiliary Building
Emergency Air Storage Tank 28	VES-MT-28	Auxiliary Building

Table 2.2.5-6 (cont.)		
Component Name	**Tag Number**	**Component Location**
Emergency Air Storage Tank 29	VES-MT-29	Auxiliary Building
Emergency Air Storage Tank 30	VES-MT-30	Auxiliary Building
Emergency Air Storage Tank 31	VES-MT-31	Auxiliary Building
Emergency Air Storage Tank 32	VES-MT-32	Auxiliary Building

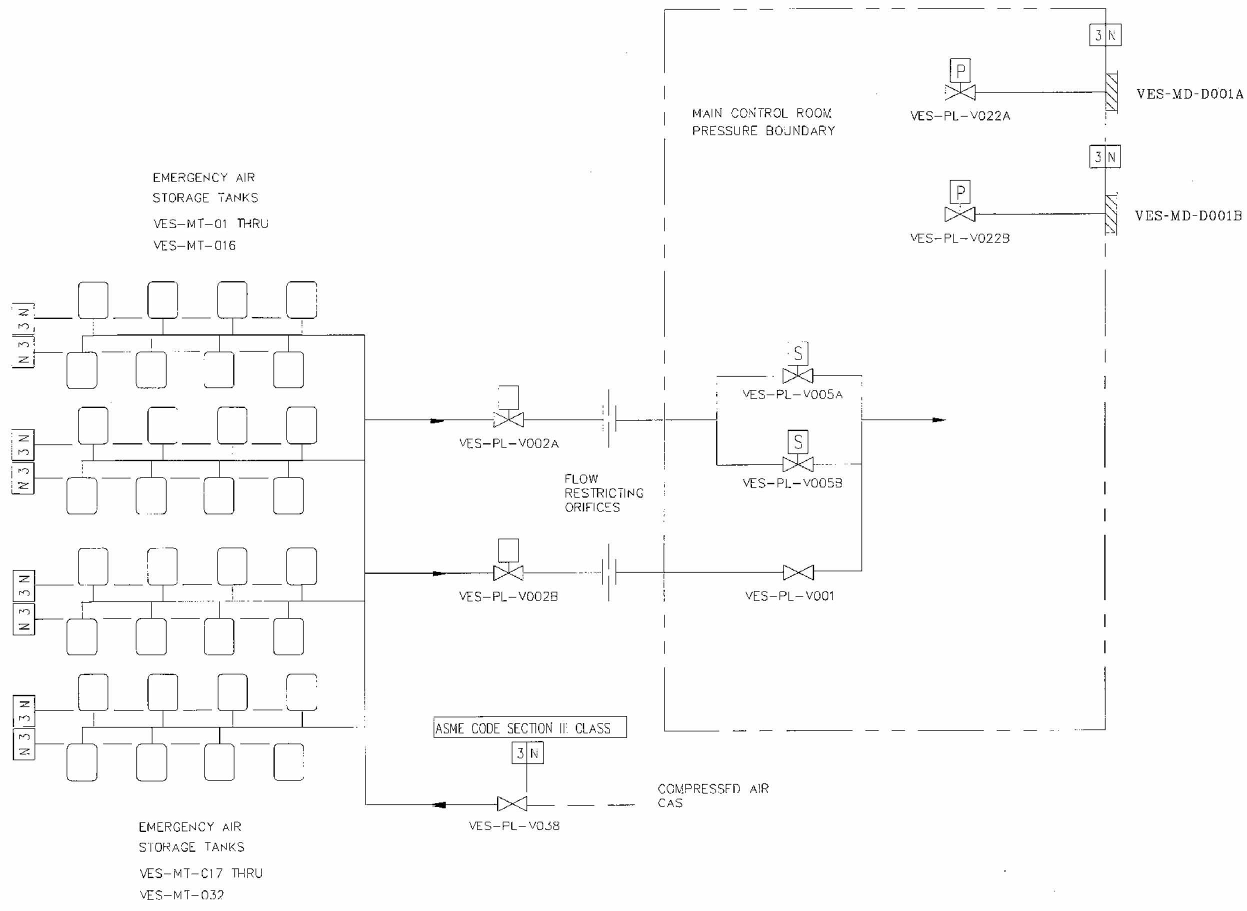


Figure 2.2.5-1
Main Control Room Emergency Habitability System

2.3.1 Component Cooling Water System

Design Description

The component cooling water system (CCS) removes heat from various plant components and transfers this heat to the service water system (SWS) during normal modes of plant operation including power generation, shutdown and refueling. The CCS has two pumps and two heat exchangers.

The CCS is as shown in Figure 2.3.1-1 and the CCS component locations are as shown in Table 2.3.1-3.

1. The functional arrangement of the CCS is as described in the Design Description of this Section 2.3.1.

2. The CCS preserves containment integrity by isolation of the CCS lines penetrating the containment.

3. The CCS provides the nonsafety-related functions of transferring heat from the normal residual heat removal system (RNS) during shutdown and the spent fuel pool cooling system during all modes of operation to the SWS.

4. Controls exist in the main control room (MCR) to cause the pumps identified in Table 2.3.1-1 to perform the listed functions.

5. Displays of the parameters identified in Table 2.3.1-1 can be retrieved in the MCR.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.3.1-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the CCS.

Table 2.3.1-1			
Equipment Name	**Tag No.**	**Display**	**Control Function**
CCS Pump A	CCS-MP-01A	Yes (Run Status)	Start
CCS Pump B	CCS-MP-01B	Yes (Run Status)	Start
CCS Discharge Header Flow Sensor	CCS-101	Yes	-
CCS to Normal Residual Heat Removal System Heat Exchanger (RNS HX) A Flow Sensor	CCS-301	Yes	-
CCS to RNS HX B Flow Sensor	CCS-302	Yes	-
CCS to Spent Fuel Pool Cooling System (SFS) HX A Flow Sensor	CCS-341	Yes	-
CCS to SFS HX B Flow Sensor	CCS-342	Yes	-
CCS Surge Tank Level Sensor	CCS-130	Yes	-
CCS Heat Exchanger Inlet Temperature Sensor	CCS-121	Yes	-
CCS Heat Exchanger Outlet Temperature Sensor	CCS-122	Yes	-
CCS Flow to Reactor Coolant Pump (RCP) 1A Valve (Position Indicator)	CCS-PL-V256A	Yes	-
CCS Flow to RCP 1B Valve (Position Indicator)	CCS-PL-V256B	Yes	-
CCS Flow to RCP 2A Valve (Position Indicator)	CCS-PL-V256C	Yes	-
CCS Flow to RCP 2B Valve (Position Indicator)	CCS-PL-V256D	Yes	-

Note: Dash (-) indicates not applicable.

Table 2.3.1-2

Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the CCS is as described in the Design Description of this Section 2.3.1.	Inspection of the as-built system will be performed.	The as-built CCS conforms with the functional arrangement described in the Design Description of this Section 2.3.1.
2. The CCS preserves containment integrity by isolation of the CCS lines penetrating the containment.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.
3. The CCS provides the nonsafety-related functions of transferring heat from the RNS during shutdown and the spent fuel pool cooling system during all modes of operation to the SWS.	i) Inspection will be performed for the existence of a report that determines the heat transfer capability of the CCS heat exchangers. ii) Testing will be performed to confirm that the CCS can provide cooling water to the RNS HXs while providing cooling water to the SFS HXs.	i) A report exists and concludes that the UA of each CCS heat exchanger is greater than or equal to 12.1 million Btu/hr-°F. ii) Each pump of the CCS can provide at least 2685 gpm of cooling water to one RNS HX and at least 1125 gpm of cooling water to one SFS HX while providing at least 1140 gpm to other users of cooling water.
4. Controls exist in the MCR to cause the pumps identified in Table 2.3.1-1 to perform the listed functions.	Testing will be performed to actuate the pumps identified in Table 2.3.1-1 using controls in the MCR.	Controls in the MCR operate to cause pumps listed in Table 2.3.1-1 to perform the listed functions.
5. Displays of the parameters identified in Table 2.3.1-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the parameters in the MCR.	Displays identified in Table 2.3.1-1 can be retrieved in the MCR.

Table 2.3.1-3		
Component Name	**Tag No.**	**Component Location**
CCS Pump A	CCS-MP-01A	Turbine Building
CCS Pump B	CCS-MP-01B	Turbine Building
CCS Heat Exchanger A	CCS-ME-01A	Turbine Building
CCS Heat Exchanger B	CCS-ME-01B	Turbine Building

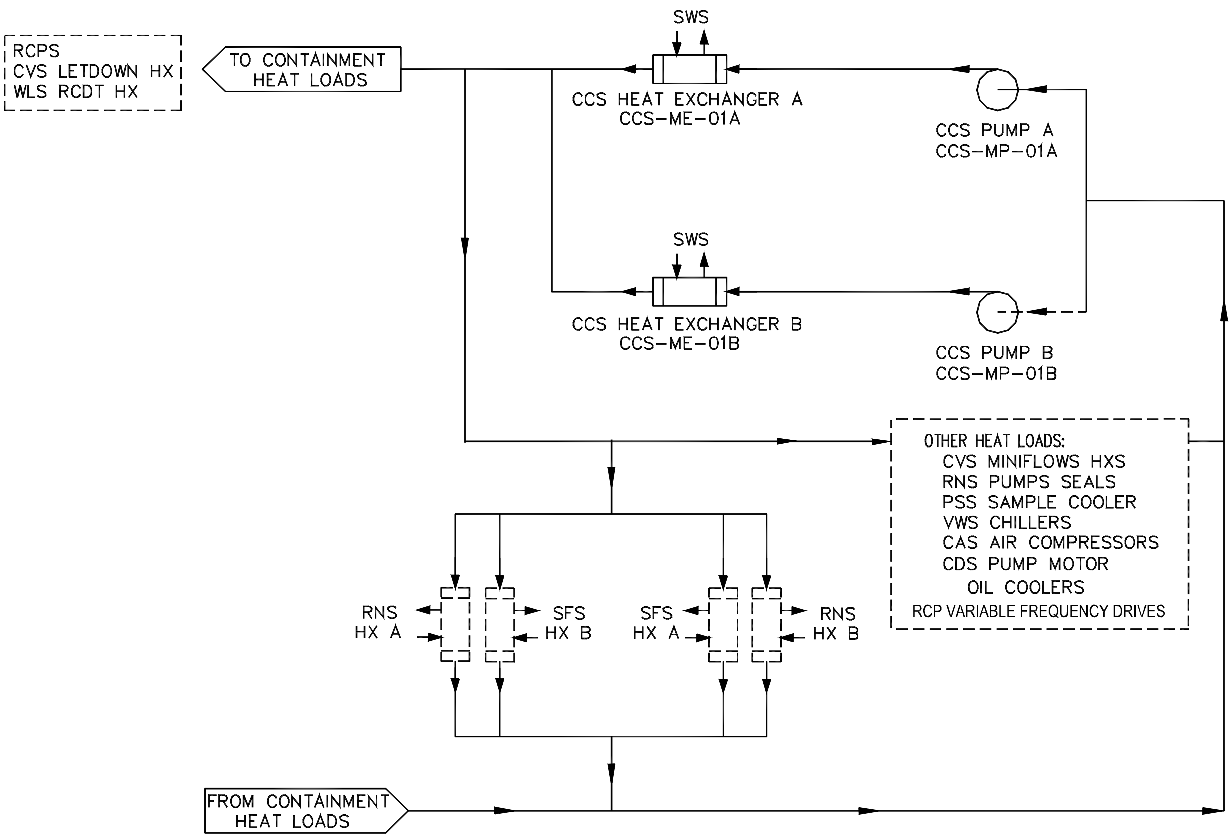


Figure 2.3.1-1
Component Cooling Water System

2.3.2 Chemical and Volume Control System

Design Description

The chemical and volume control system (CVS) provides reactor coolant system (RCS) purification, RCS inventory control and makeup, chemical shim and chemical control, and oxygen control, and provides for auxiliary pressurizer spray. The CVS performs these functions during normal modes of operation including power generation and shutdown.

The CVS is as shown in Figure 2.3.2-1 and the component locations of the CVS are as shown in Table 2.3.2-5.

1. The functional arrangement of the CVS is as described in the Design Description of this Section 2.3.2.

2. a) The components identified in Table 2.3.2-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.

   b) The piping identified in Table 2.3.2-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.

3. a) Pressure boundary welds in components identified in Table 2.3.2-1 as ASME Code Section III meet ASME Code Section III requirements.

   b) Pressure boundary welds in piping identified in Table 2.3.2-2 as ASME Code Section III meet ASME Code Section III requirements.

4. a) The components identified in Table 2.3.2-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.

   b) The piping identified in Table 2.3.2-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.

5. The seismic Category I equipment identified in Table 2.3.2-1 can withstand seismic design basis loads without loss of safety function.

6. a) The Class 1E equipment identified in Table 2.3.2-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.

   b) The Class 1E components identified in Table 2.3.2-1 are powered from their respective Class 1E division.

   c) Separation is provided between CVS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.

7. The CVS provides the following safety-related functions:

    a) The CVS preserves containment integrity by isolation of the CVS lines penetrating the containment.

    b) The CVS provides termination of an inadvertent RCS boron dilution by isolating demineralized water from the RCS.

    c) The CVS provides isolation of makeup to the RCS.

8. The CVS provides the following nonsafety-related functions:

    a) The CVS provides makeup water to the RCS.

    b) The CVS provides the pressurizer auxiliary spray.

9. Safety-related displays in Table 2.3.2-1 can be retrieved in the main control room (MCR).

10. a) Controls exist in the MCR to cause the remotely operated valves identified in Table 2.3.2-1 to perform active functions.

    b) The valves identified in Table 2.3.2-1 as having protection and safety monitoring system (PMS) control perform an active safety function after receiving a signal from the PMS.

11. a) The motor-operated and check valves identified in Table 2.3.2-1 perform an active safety-related function to change position as indicated in the table.

    b) After a loss of motive power, the remotely operated valves identified in Table 2.3.2-1 assume the indicated loss of motive power position.

12. a) Controls exist in the MCR to cause the pumps identified in Table 2.3.2-3 to perform the listed function.

    b) The pumps identified in Table 2.3.2-3 start after receiving a signal from the PLS.

13. Displays of the parameters identified in Table 2.3.2-3 can be retrieved in the MCR.

14. The nonsafety-related piping located inside containment and designated as reactor coolant pressure boundary, as identified in Table 2.3.2-2 (pipe lines with "No" in the ASME Code column), has been designed to withstand a seismic design basis event and maintain structural integrity.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.3.2-4 specifies the inspections, tests, analyses, and associated acceptance criteria for the CVS.

Table 2.3.2-1

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS	Active Function	Loss of Motive Power Position
RCS Purification Motor-operated Isolation Valve	CVS-PL-V001	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	As Is
RCS Purification Motor-operated Isolation Valve	CVS-PL-V002	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	As Is
RCS Purification Motor-operated Isolation Valve	CVS-PL-V003	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	As Is
CVS Resin Flush Line Containment Isolation Valve	CVS-PL-V040	Yes	Yes	No	- / -	-	-	-	-
CVS Resin Flush Line Containment Isolation Valve	CVS-PL-V041	Yes	Yes	No	- / -	-	-	-	-
CVS Demineralizer Resin Flush Line Containment Isolation Thermal Relief Valve	CVS-PL-V042	Yes	Yes	No	- / -	-	-	Transfer Open/ Transfer Closed	-
CVS Letdown Containment Isolation Valve	CVS-PL-V045	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	Closed
CVS Letdown Containment Isolation Valve	CVS-PL-V047	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes	Transfer Closed	Closed

Note: Dash (-) indicates not applicable.

Table 2.3.2-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS**	**Active Function**	**Loss of Motive Power Position**
CVS Purification Return Line Pressure Boundary Check Valve	CVS-PL-V080	Yes	Yes	No	- / -	-	-	Transfer Closed	-
CVS Purification Return Line Pressure Boundary Isolation Check Valve	CVS-PL-V081	Yes	Yes	No	- / -	No	-	Transfer Closed	-
CVS Purification Return Line Pressure Boundary Check Valve	CVS-PL-V082	Yes	Yes	No	- / -	-	-	Transfer Closed	-
CVS Auxiliary Pressurizer Spray Line Pressure Boundary Valve	CVS-PL-V084	Yes	Yes	Yes	Yes/Yes	No	Yes	Transfer Closed	Closed
CVS Auxiliary Pressurizer Spray Line Pressure Boundary Check Valve	CVS-PL-V085	Yes	Yes	No	Yes/Yes	-	-	Transfer Closed	-
CVS Makeup Line Containment Isolation Motor-operated Valve	CVS-PL-V090	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes	Transfer Closed	As Is
CVS Makeup Line Containment Isolation Motor-operated Valve	CVS-PL-V091	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	As Is
CVS Hydrogen Addition Line Containment Isolation Valve	CVS-PL-V092	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes	Transfer Closed	Closed

Note: Dash (-) indicates not applicable.

Table 2.3.2-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS**	**Active Function**	**Loss of Motive Power Position**
CVS Hydrogen Addition Line Containment Isolation Check Valve	CVS-PL-V094	Yes	Yes	No	- / -	-	-	Transfer Closed	-
CVS Makeup Line Containment Isolation Thermal Relief Valve	CVS-PL-V100	Yes	Yes	No	- / -	-	-	Transfer Open/ Transfer Closed	-
CVS Demineralized Water Isolation Valve	CVS-PL-V136A	Yes	Yes	Yes	Yes/No	No	Yes	Transfer Closed	Closed
CVS Demineralized Water Isolation Valve	CVS-PL-V136B	Yes	Yes	Yes	Yes/No	No	Yes	Transfer Closed	Closed

Note: Dash (-) indicates not applicable.

Table 2.3.2-2		
Line Name	**Line Number**	**ASME Code Section III**
CVS Purification Line	BTA L001 BBC L040	Yes Yes
CVS Resin Flush Containment Penetration Line	BBB L026	Yes
CVS Purification Line Return	BTA L038	Yes
CVS Pressurizer Auxiliary Spray Connection	BBC L070 BTA L071	Yes Yes
CVS Letdown Containment Penetration Line	BBB L051	Yes
CVS Makeup Containment Penetration Line	BBB L053	Yes
CVS Hydrogen Addition Containment Penetration Line	BBB L061	Yes
CVS Supply Line to Regenerative Heat Exchanger	BBD L002	No
CVS Return Line from Regenerative Heat Exchanger	BBD L018 BBC L036 BBD L073	No Yes No
CVS Line from Regenerative Heat Exchanger to Letdown Heat Exchanger	BBD L003 BBD L072	No No
CVS Lines from Letdown Heat Exchanger to Demin. Tanks	BBD L004 BBD L005	No No
CVS Lines from Demin Tanks to RC Filters and Connected Lines	BBD L006(1) BBD L007(1) BBD L010(1) BBD L011(1) BBD L012 BBD L015(1) BBD L016(1) BBD L020 BBD L021 BBD L022 BBD L023(1) BBD L024(1) BBD L029 BBD L037	No No No No No No No No No No No No No No

Table 2.3.2-2 (cont.)		
Line Name	**Line Number**	**ASME Code Section III**
CVS Lines from RC Filters to Regenerative Heat Exchanger	BBD L030 BBD L031 BBD L034 BBD L050	No No No No
CVS Resin Fill Lines to Demin. Tanks	BBD L008(1) BBD L013(1) BBD L025(1)	No No No

Note:

1. Special seismic requirements include only the portion of piping normally exposed to RCS pressure. Piping beyond the first normally closed isolation valve is evaluated as seismic Category II piping extending to either an interface anchor, a rigid support following a six-way anchor, or the last seismic support of a rigidly supported region of the piping system as necessary to satisfy analysis requirements for piping connected to seismic Category I piping systems.

Table 2.3.2-3			
Equipment	**Tag No.**	**Display**	**Control Function**
CVS Makeup Pump A	CVS-MP-01A	Yes (Run Status)	Start
CVS Makeup Pump B	CVS-MP-01B	Yes (Run Status)	Start
Letdown Flow Sensor	CVS-001	Yes	-
Letdown Flow Sensor	CVS-025	Yes	-
CVS Purification Return Line (Position Indicator)	CVS-PL-V081	Yes	-
Auxiliary Spray Line Isolation Valve (Position Indicator)	CVS-PL-V084	Yes	-
Boric Acid Tank Level Sensor	CVS-109	Yes	-
Boric Acid Flow Sensor	CVS-115	Yes	-
Makeup Blend Valve (Position Indicator)	CVS-PL-V115	Yes	-
CVS Demineralized Water Isolation Valve (Position Indicator)	CVS-PL-136A	Yes	-
CVS Demineralized Water Isolation Valve (Position Indicator)	CVS-PL-136B	Yes	-
Makeup Pump Discharge Flow Sensor	CVS-157	Yes	-
Makeup Flow Control Valve (Position Indicator)	CVS-PL-V157	Yes	-

Note: Dash (-) indicates not applicable.

Table 2.3.2-4
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the CVS is as described in the Design Description of this Section 2.3.2.	Inspection of the as-built system will be performed.	The as-built CVS conforms with the functional arrangement as described in the Design Description of this Section 2.3.2.
2.a) The components identified in Table 2.3.2-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built components as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built components identified in Table 2.3.2-1 as ASME Code Section III.
2.b) The piping identified in Table 2.3.2-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built piping as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built piping identified in Table 2.3.2-2 as ASME Code Section III.
3.a) Pressure boundary welds in components identified in Table 2.3.2-1 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
3.b) Pressure boundary welds in piping identified in Table 2.3.2-2 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
4.a) The components identified in Table 2.3.2-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.	A hydrostatic test will be performed on the components required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the components identified in Table 2.3.2-1 as ASME Code Section III conform with the requirements of the ASME Code Section III.

Table 2.3.2-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4.b) The piping identified in Table 2.3.2-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.	A hydrostatic test will be performed on the piping required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the piping identified in Table 2.3.2-2 as ASME Code Section III conform with the requirements of the ASME Code Section III.
5. The seismic Category I equipment identified in Table 2.3.2-1 can withstand seismic design basis loads without loss of safety function.	i) Inspection will be performed to verify that the seismic Category I equipment identified in Table 2.3.2-1 is located on the Nuclear Island.	i) The seismic Category I equipment identified in Table 2.3.2-1 is located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis dynamic loads without loss of safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) A report exists and concludes that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.
6.a) The Class 1E equipment identified in Table 2.3.2-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.	i) Type tests, analyses, or a combination of type tests and analyses will be performed on Class 1E equipment located in a harsh environment.	i) A report exists and concludes that the Class 1E equipment identified in Table 2.3.2-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.
	ii) Inspection will be performed of the as-installed Class 1E equipment and the associated wiring, cables, and terminations located in a harsh environment.	ii) A report exists and concludes that the as-installed Class 1E equipment and the associated wiring, cables, and terminations identified in Table 2.3.2-1 as being qualified for a harsh environment are bounded by type tests, analyses, or a combination of type tests and analyses.

Table 2.3.2-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6.b) The Class 1E components identified in Table 2.3.2-1 are powered from their respective Class 1E division.	Testing will be performed on the CVS by providing a simulated test signal in each Class 1E division.	A simulated test signal exists at the Class 1E equipment identified in Table 2.3.2-1 when the assigned Class 1E division is provided the test signal.
6.c) Separation is provided between CVS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.	See Tier 1 Material, Table 3.3-6, item 7.d.	See Tier 1 Material, Table 3.3-6, item 7.d.
7.a) The CVS preserves containment integrity by isolation of the CVS lines penetrating the containment.	See Tier 1 Material, Table 2.2.1-3, item 7.	See Tier 1 Material, Table 2.2.1-3, item 7.
7.b) The CVS provides termination of an inadvertent RCS boron dilution by isolating demineralized water from the RCS.	See item 10b in this table.	See item 10b in this table.
7.c) The CVS provides isolation of makeup to the RCS.	See item 10b in this table.	See item 10b in this table.
8.a) The CVS provides makeup water to the RCS.	i) Testing will be performed by aligning a flow path from each CVS makeup pump, actuating makeup flow to the RCS at pressure greater than or equal to 2000 psia, and measuring the flow rate in the makeup pump discharge line with each pump suction aligned to the boric acid tank.	i) Each CVS makeup pump provides a flow rate of greater than or equal to 100 gpm.
	ii) Inspection of the boric acid tank volume will be performed.	ii) The volume in the boric acid tank is at least 70,000 gallons between the tank outlet connection and the tank overflow.
	iii) Testing will be performed to measure the delivery rate from the DWS to the RCS. Both CVS makeup pumps will be operating and the RCS pressure will be below 6 psig.	iii) The total CVS makeup flow to the RCS is less than or equal to 200 gpm.

Table 2.3.2-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
8.b) The CVS provides the pressurizer auxiliary spray.	Testing will be performed by aligning a flow path from each CVS makeup pump to the pressurizer auxiliary spray and measuring the flow rate in the makeup pump discharge line with each pump suction aligned to the boric acid tank and with RCS pressure greater than or equal to 2000 psia.	Each CVS makeup pump provides spray flow to the pressurizer.
9. Safety-related displays identified in Table 2.3.2-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the safety-related displays in the MCR.	Safety-related displays identified in Table 2.3.2-1 can be retrieved in the MCR.
10.a) Controls exist in the MCR to cause the remotely operated valves identified in Table 2.3.2-1 to perform active functions.	Stroke testing will be performed on the remotely operated valves identified in Table 2.3.2-1 using the controls in the MCR.	Controls in the MCR operate to cause the remotely operated valves identified in Table 2.3.2-1 to perform active functions.
10.b) The valves identified in Table 2.3.2-1 as having PMS control perform an active safety function after receiving a signal from the PMS.	i) Testing will be performed using real or simulated signals into the PMS.	i) The valves identified in Table 2.3.2-1 as having PMS control perform the active function identified in the table after receiving a signal from the PMS.
	ii) Testing will be performed to demonstrate that the remotely operated CVS isolation valves CVS-V090, V091, V136A/B close within the required response time.	ii) These valves close within the following times after receipt of an actuation signal: V090, V091 < 10 sec V136A/B < 20 sec
11.a) The motor-operated and check valves identified in Table 2.3.2-1 perform an active safety-related function to change position as indicated in the table.	i) Tests or type tests of motor-operated valves will be performed that demonstrate the capability of the valve to operate under its design conditions.	i) A test report exists and concludes that each motor-operated valve changes position as indicated in Table 2.3.2-1 under design conditions.
	ii) Inspection will be performed for the existence of a report verifying that the as-installed motor-operated valves are bounded by the tested conditions.	ii) A report exists and concludes that the as-installed motor-operated valves are bounded by the tests or type tests.

Table 2.3.2-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
	iii) Tests of the as-installed motor-operated valves will be performed under pre-operational flow, differential pressure, and temperature conditions. iv) Exercise testing of the check valves with active safety functions identified in Table 2.3.2-1 will be performed under pre-operational test pressure, temperature and fluid flow conditions.	iii) Each motor-operated valve changes position as indicated in Table 2.3.2-1 under pre-operational test conditions. iv) Each check valve changes position as indicated in Table 2.3.2-1.
11.b) After loss of motive power, the remotely operated valves identified in Table 2.3.2-1 assume the indicated loss of motive power position.	Testing of the installed valves will be performed under the conditions of loss of motive power.	Upon loss of motive power, each remotely operated valve identified in Table 2.3.2-1 assumes the indicated loss of motive power position.
12.a) Controls exist in the MCR to cause the pumps identified in Table 2.3.2-3 to perform the listed function.	Testing will be performed to actuate the pumps identified in Table 2.3.2-3 using controls in the MCR.	Controls in the MCR cause pumps identified in Table 2.3.2-3 to perform the listed function.
12.b) The pumps identified in Table 2.3.2-3 start after receiving a signal from the PLS.	Testing will be performed to confirm starting of the pumps identified in Table 2.3.2-3.	The pumps identified in Table 2.3.2-3 start after a signal is generated by the PLS.
13. Displays of the parameters identified in Table 2.3.2-3 can be retrieved in the MCR.	Inspection will be performed for retrievability of the displays identified in Table 2.3.2-3 in the MCR.	Displays identified in Table 2.3.2-3 can be retrieved in the MCR.
14. The nonsafety-related piping located inside containment and designated as reactor coolant pressure boundary, as identified in Table 2.3.2-2, has been designed to withstand a seismic design basis event and maintain structural integrity.	Inspection will be conducted of the as-built components as documented in the CVS Seismic Analysis Report.	The CVS Seismic Analysis Reports exist for the non-safety related piping located inside containment and designated as reactor coolant pressure boundary as identified in Table 2.3.2-2.

Table 2.3.2-5		
Component Name	**Tag No.**	**Component Location**
CVS Makeup Pump A	CVS-MP-01A	Auxiliary Building
CVS Makeup Pump B	CVS-MP-01B	Auxiliary Building
Boric Acid Tank	CVS-MT-02	Yard
Regenerative Heat Exchanger	CVS-ME-01	Containment
Letdown Heat Exchanger	CVS-ME-02	Containment
Mixed Bed Demineralizer A	CVS-MV-01A	Containment
Mixed Bed Demineralizer B	CVS-MV-01B	Containment
Cation Bed Demineralizer	CVS-MV-02	Containment
Reactor Coolant Filter A	CVS-MV-03A	Containment
Reactor Coolant Filter B	CVS-MV-03B	Containment

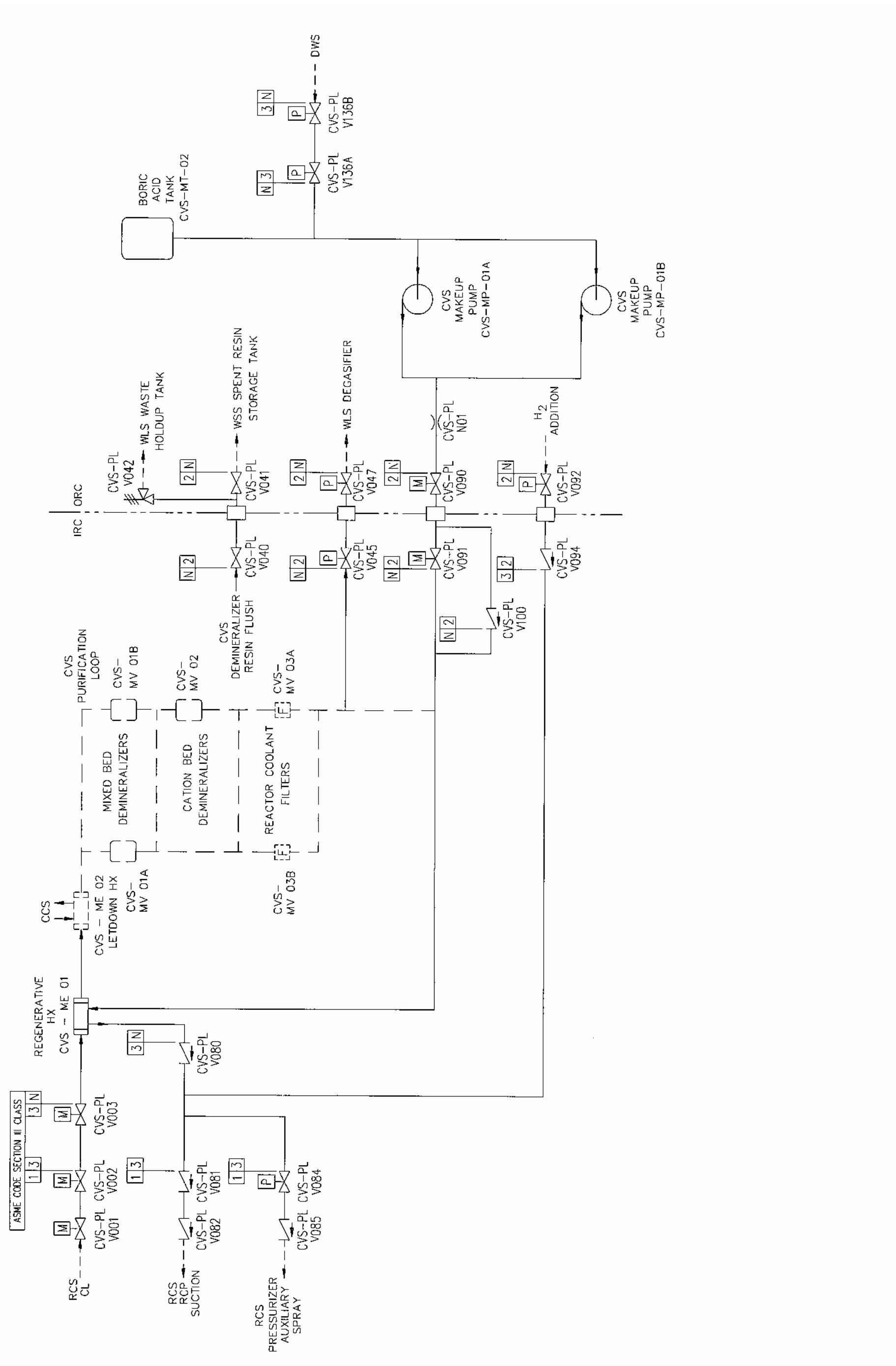


Figure 2.3.2-1
Chemical and Volume Control System

2.3.3 Standby Diesel and Auxiliary Boiler Fuel Oil System

Design Description

The standby diesel and auxiliary boiler fuel oil system (DOS) supplies diesel fuel oil for the onsite standby power system. The diesel fuel oil is supplied by two above-ground fuel oil storage tanks. The DOS also provides fuel oil for the ancillary diesel generators. A single fuel oil storage tank services both ancillary diesel generators.

The DOS is as shown in Figure 2.3.3-1 and the component locations of the DOS are as shown in Table 2.3.3-3.

1. The functional arrangement of the DOS is as described in the Design Description of this Section 2.3.3.

2. The ancillary diesel generator fuel tank can withstand a seismic event.

3. The DOS provides the following nonsafety-related functions:

   a) Each fuel oil storage tank provides for at least 7 days of continuous operation of the associated standby diesel generator.

   b) Each fuel oil day tank provides for at least four hours of continuous operation of the associated standby diesel engine generator.

   c) The fuel oil flow rate to the day tank of each standby diesel generator provides for continuous operation of the associated diesel generator.

   d) The ancillary diesel generator fuel tank is sized to supply power to long-term safety-related post-accident monitoring loads and control room lighting through a regulating transformer and one PCS recirculation pump for a period of 4 days.

4. Controls exist in the main control room (MCR) to cause the components identified in Table 2.3.3-1 to perform the listed function.

5. Displays of the parameters identified in Table 2.3.3-1 can be retrieved in the MCR.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.3.3-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the DOS.

Table 2.3.3-1			
Equipment Name	**Tag No.**	**Display**	**Control Function**
Diesel Fuel Oil Pump 1A (Motor)	DOS-MP-01A	Yes (Run Status)	Start
Diesel Fuel Oil Pump 1B (Motor)	DOS-MP-01B	Yes (Run Status)	Start
Diesel Generator Fuel Oil Day Tank A Level	DOS-016A	Yes	-
Diesel Generator Fuel Oil Day Tank B Level	DOS-016B	Yes	-

Note: Dash (-) indicates not applicable.

Table 2.3.3-2
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the DOS is as described in the Design Description of this Section 2.3.3.	Inspection of the as-built system will be performed.	The as-built DOS conforms with the functional arrangement described in the Design Description of this Section 2.3.3.
2. The ancillary diesel generator fuel tank can withstand a seismic event.	Inspection will be performed for the existence of a report verifying that the as-installed ancillary diesel generator fuel tank and its anchorage are designed using seismic Category II methods and criteria.	A report exists and concludes that the as-installed ancillary diesel generator fuel tank and its anchorage are designed using seismic Category II methods and criteria.
3.a) Each fuel oil storage tank provides for at least 7 days of continuous operation of the associated standby diesel generator.	Inspection of each fuel oil storage tank will be performed.	The volume of each fuel oil storage tank between the diesel generator fuel oil day tank supply connection and the auxiliary boiler supply connection is greater than or equal to 55,000 gallons.
3.b) Each fuel oil storage day tank provides for at least 4 hours of operation of the associated standby diesel generator.	Inspection of the fuel oil day tank will be performed.	The volume of each fuel oil day tank is greater than or equal to 1300 gallons.
3.c) The fuel oil flow rate to the day tank of each standby diesel generator provides for continuous operation of the associated diesel generator.	Testing will be performed to determine the flow rate.	The flow rate delivered to each day tank is 8 gpm or greater.
3.d) The ancillary diesel generator fuel tank is sized to supply power to long-term safety-related post accident monitoring loads and control room lighting through a regulating transformer and one PCS recirculation pump for four days.	Inspection of the ancillary diesel generator fuel tank will be performed.	The volume of the ancillary diesel generator fuel tank is greater than or equal to 650 gallons.
4. Controls exist in the MCR to cause the components identified in Table 2.3.3-1 to perform the listed function.	Testing will be performed on the components in Table 2.3.3-1 using controls in the MCR.	Controls in the MCR operate to cause the components listed in Table 2.3.3-1 to perform the listed functions.
5. Displays of the parameters identified in Table 2.3.3-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of parameters in the MCR.	The displays identified in Table 2.3.3-1 can be retrieved in the MCR.

Table 2.3.3-3		
Component Name	**Tag No.**	**Component Location**
Diesel Oil Transfer Package A	DOS-MS-01A	Yard
Diesel Oil Transfer Package B	DOS-MS-01B	Yard
Fuel Oil Storage Tank A	DOS-MT-01A	Yard
Fuel Oil Storage Tank B	DOS-MT-01B	Yard
Diesel Generator A Fuel Oil Day Tank	DOS-MT-02A	Diesel Building
Diesel Generator B Fuel Oil Day Tank	DOS-MT-02B	Diesel Building
Ancillary Diesel Fuel Oil Storage Tank	DOS-MT-03	Annex Building

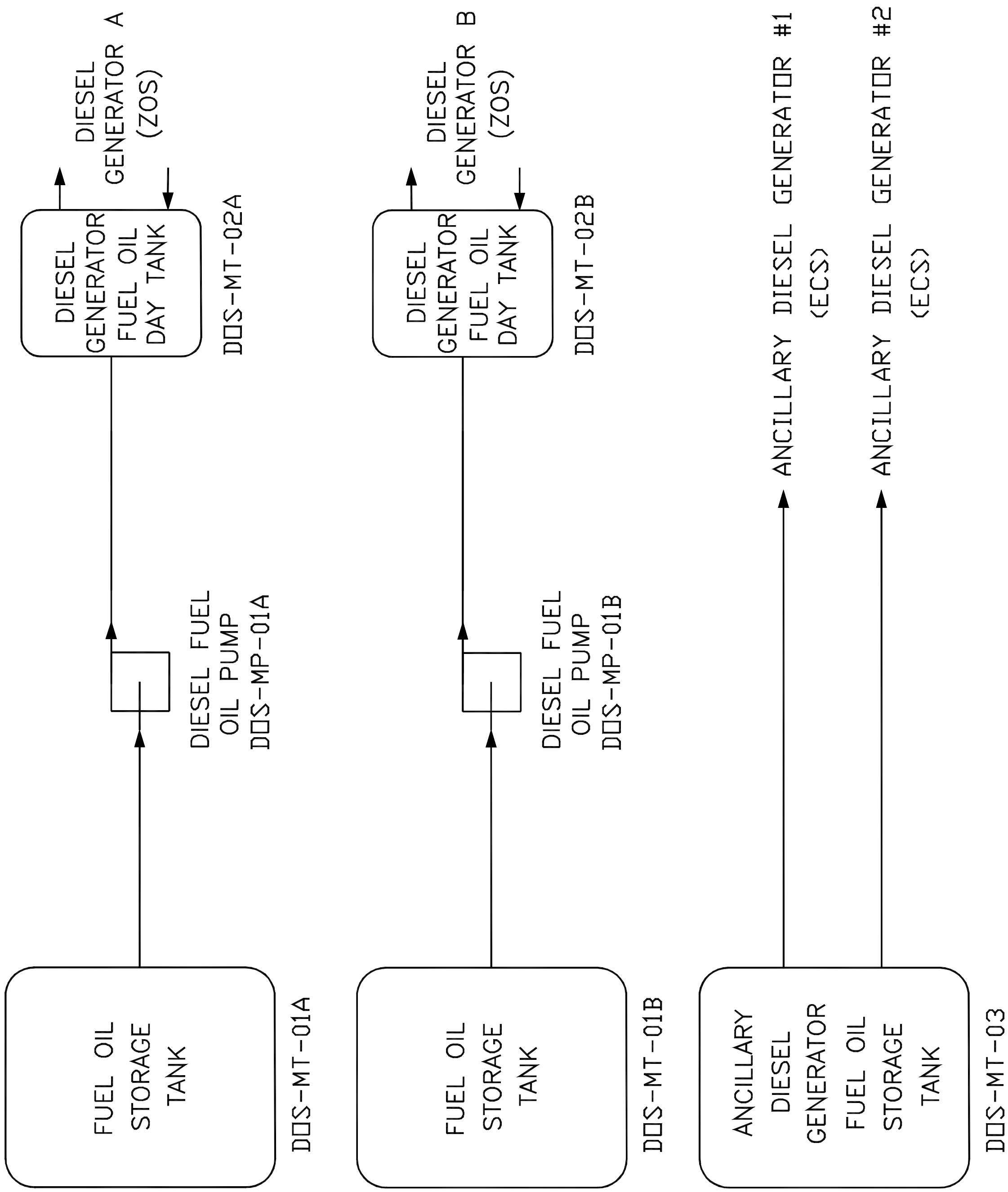


Figure 2.3.3-1
Standby Diesel and Auxiliary Boiler Fuel Oil System

2.3.4 Fire Protection System

Design Description

The fire protection system (FPS) detects and suppresses fires in the plant. The FPS consists of water distribution systems, automatic and manual suppression systems, a fire detection and alarm system, and portable fire extinguishers. The FPS provides fire protection for the nuclear island, the annex building, the turbine building, the radwaste building and the diesel generator building.

The FPS is as shown in Figure 2.3.4-1 and the component locations of the FPS are as shown in Table 2.3.4-3.

1. The functional arrangement of the FPS is as described in the Design Description of this Section 2.3.4.

2. The FPS piping identified in Table 2.3.4-4 remains functional following a safe shutdown earthquake.

3. The FPS provides the safety-related function of preserving containment integrity by isolation of the FPS line penetrating the containment.

4. The FPS provides for manual fire fighting capability in plant areas containing safety-related equipment.

5. Displays of the parameters identified in Table 2.3.4-1 can be retrieved in the main control room (MCR).

6. The FPS provides nonsafety-related containment spray for severe accident management.

7. The FPS provides two fire water storage tanks, each capable of holding at least 300,000 gallons of water.

8. Two FPS fire pumps provide at least 2000 gpm each at a total head of at least 300 ft.

9. The fuel tank for the diesel-driven fire pump is capable of holding at least 240 gallons.

10. Individual fire detectors provide fire detection capability and can be used to initiate fire alarms in areas containing safety-related equipment.

11. The FPS seismic standpipe subsystem can be supplied from the FPS fire main by opening the normally closed cross-connect valve to the FPS plant fire main.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.3.4-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the FPS.

Table 2.3.4-1			
Equipment Name	**Tag No.**	**Display**	**Control Function**
Motor-driven Fire Pump	FPS-MP-01A	Yes (Run Status)	Start
Diesel-driven Fire Pump	FPS-MP-01B	Yes (Run Status)	Start
Jockey Pump	FPS-MP-02	Yes (Run Status)	Start

Table 2.3.4-2
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the FPS is as described in the Design Description of this Section 2.3.4.	Inspection of the as-built system will be performed.	The as-built FPS conforms with the functional arrangement described in the Design Description of this Section 2.3.4.
2. The FPS piping identified in Table 2.3.4-4 remains functional following a safe shutdown earthquake.	i) Inspection will be performed to verify that the piping identified in Table 2.3.4-4 is located on the Nuclear Island.	i) The piping identified in Table 2.3.4-4 is located on the Nuclear Island.
	ii) A reconciliation analysis using the as-designed and as-built piping information will be performed, or an analysis of the as-built piping will be performed.	ii) The as-built piping stress report exists and concludes that the piping remains functional following a safe shutdown earthquake.
3. The FPS provides the safety-related function of preserving containment integrity by isolation of the FPS line penetrating the containment.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.
4. The FPS provides for manual fire fighting capability in plant areas containing safety-related equipment.	i) Inspection of the passive containment cooling system (PCS) storage tank will be performed.	i) The volume of the PCS tank above the standpipe feeding the FPS and below the overflow is at least 18,000 gal.
	ii) Testing will be performed by measuring the water flow rate as it is simultaneously discharged from the two highest fire-hose stations and when the water for the fire is supplied from the PCS storage tank.	ii) Water is simultaneously discharged from each of the two highest fire-hose stations at not less than 75 gpm.

Table 2.3.4-2 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. Displays of the parameters identified in Table 2.3.4-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the parameters in the MCR.	The displays identified in Table 2.3.4-1 can be retrieved in the MCR.
6. The FPS provides nonsafety-related containment spray for severe accident management.	Inspection of the containment spray headers will be performed.	The FPS has spray headers and nozzles as follows: At least 44 nozzles at plant elevation of at least 260 feet, and 24 nozzles at plant elevation of at least 275 feet.
7. The FPS provides two fire water storage tanks, each capable of holding at least 300,000 gallons of water.	Inspection of each fire water storage tank will be performed.	The volume of each fire water storage tank supplying the FPS is at least 300,000 gallons.
8. Two FPS fire pumps provide at least 2000 gpm each at a total head of at least 300 ft.	Testing and/or analysis of each fire pump will be performed.	The tests and/or analysis concludes that each fire pump provides a flow rate of at least 2000 gpm at a total head of at least 300 ft.
9. The fuel tank for the diesel-driven fire pump is capable of holding at least 240 gallons.	Inspection of the diesel-driven fire pump fuel tank will be performed.	The volume of the diesel driven fire pump fuel tank is at least 240 gallons.
10. Individual fire detectors provide fire detection capability and can be used to initiate fire alarms in areas containing safety-related equipment.	Testing will be performed on the as-built individual fire detectors in the fire areas identified in Tier 1 Material, subsection 3.3, Table 3.3-3. (Individual fire detectors will be tested using simulated fire conditions.)	The tested individual fire detectors respond to simulated fire conditions.
11. The FPS seismic standpipe subsystem can be supplied from the FPS fire main by opening the normally closed cross-connect valve to the FPS plant fire main.	Inspection for the existence of a cross-connect valve from the FPS seismic standpipe subsystem to FPS plant fire main will be performed.	Valve FPS-PL-V101 exists and can connect the FPS seismic standpipe subsystem to the FPS plant fire main.

Table 2.3.4-3		
Component Name	**Tag No.**	**Location**
Motor-driven Fire Pump	FPS-MP-01A	Turbine Building
Diesel-driven Fire Pump	FPS-MP-01B	Yard
Jockey Pump	FPS-MP-02	Turbine Building
Primary Fire Water Tank	FPS-MT-01A	Yard
Secondary Fire Water/Clearwell Storage Tank	FPS-MT-01B	Yard
Fire Pump Diesel Fuel Day Tank	FPS-MT-02	Yard

Table 2.3.4-4
FPS Piping Which Must Remain Functional Following a Safe Shutdown Earthquake

L049	L114	L142	L188
L090A	L115	L143	L189
L090B	L116	L144	L190
L091A	L117	L145	L191
L091B	L118	L146	L192
L091C	L119	L147	L193
L092A	L120	L148	L194
L092B	L121	L149	L195
L092C	L122	L150	L196
L093	L123	L151	L197
L094	L124	L152	L198
L095	L125	L153	L199
L096	L126	L154	L301
L102	L127	L155	L701
L103	L128	L156	L702
L105	L129	L159	L703
L106	L130	L180	L704
L107	L131	L181	L705
L108	L132	L182	L706
L109	L133A	L183	L707
L110	L133B	L184	L708
L111	L133C	L185	L709
L112	L140	L186	
L113	L141	L187	

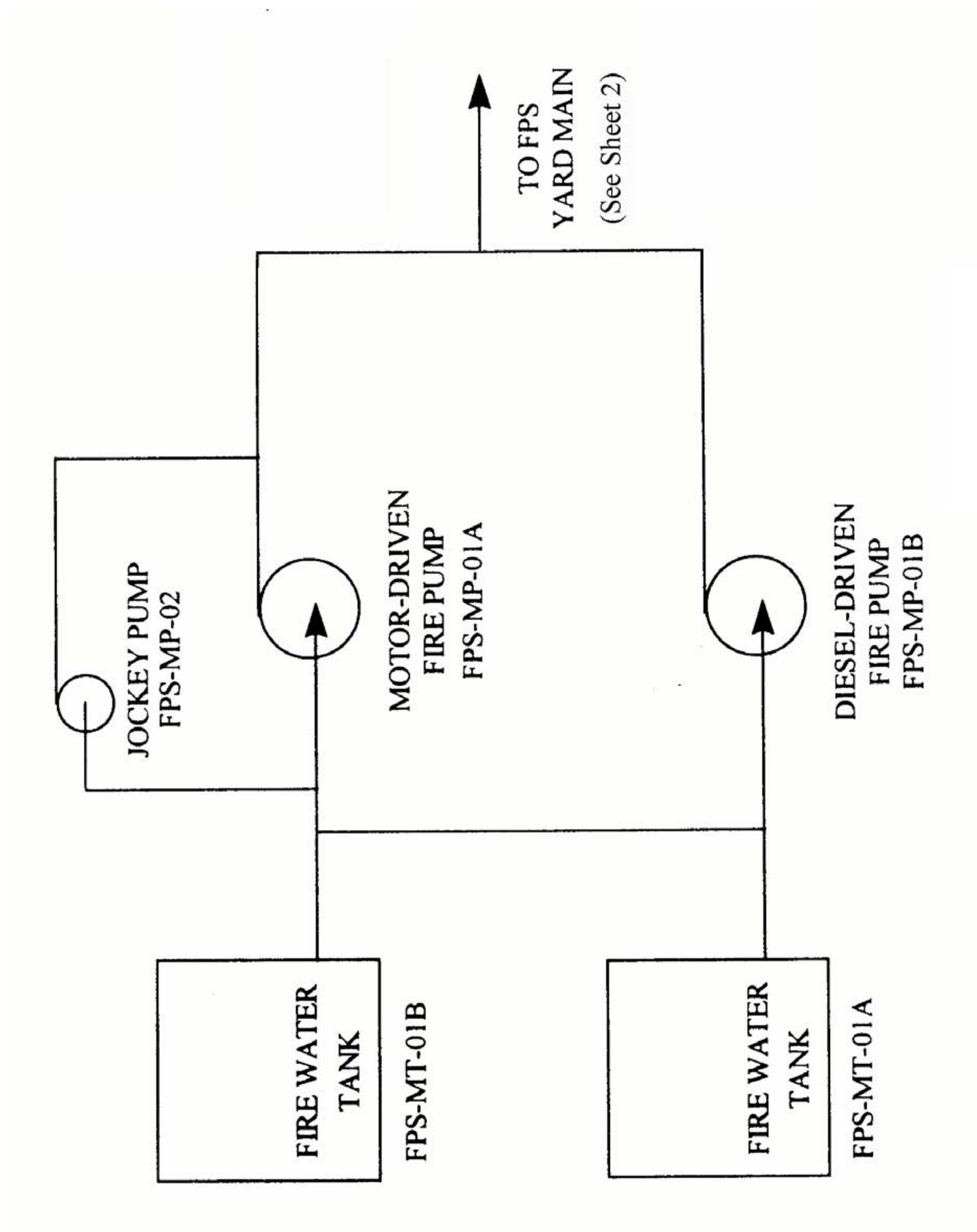


Figure 2.3.4-1 (Sheet 1 of 2)
Fire Protection System

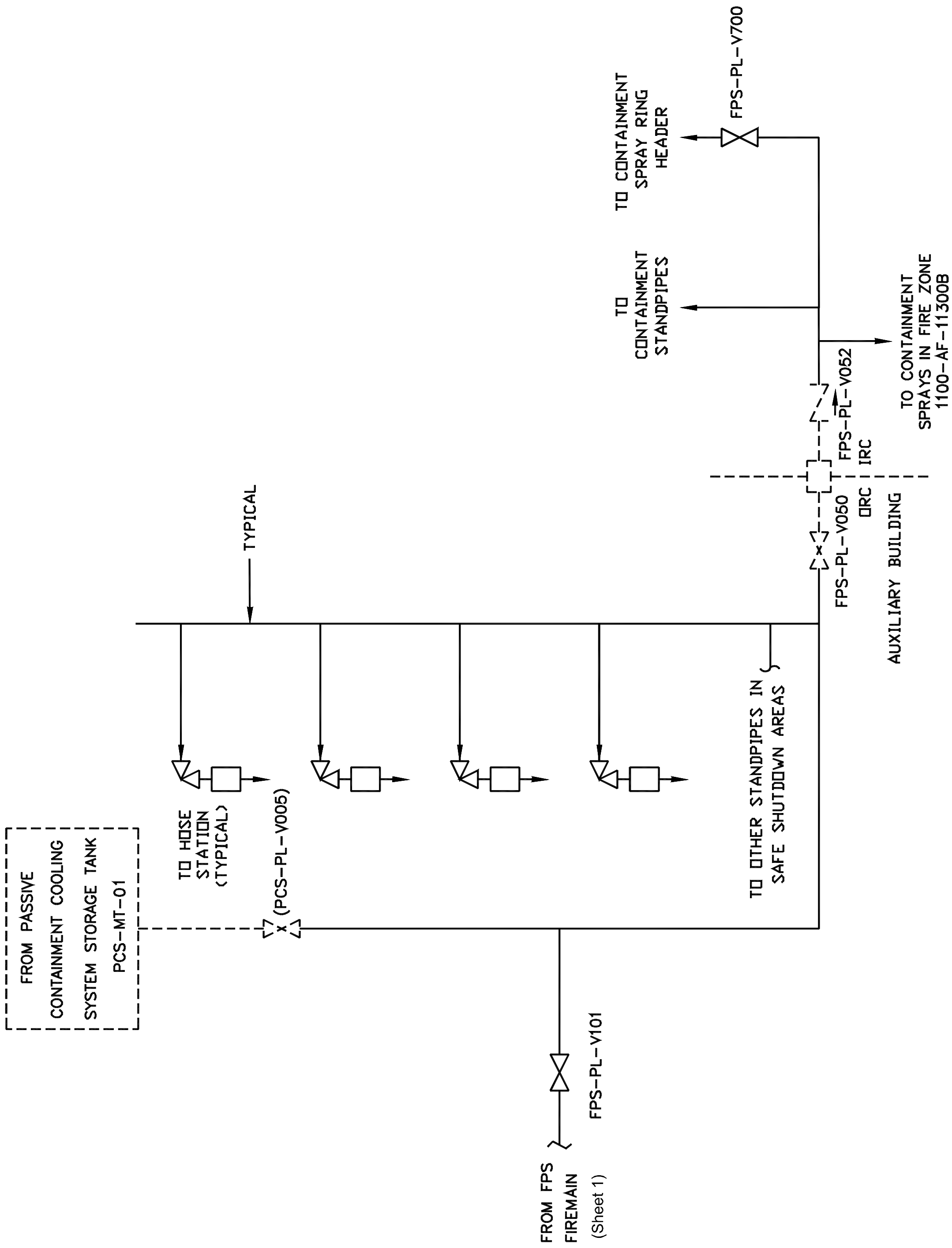


Figure 2.3.4-1 (Sheet 2 of 2)
Fire Protection System

2.3.5 Mechanical Handling System

Design Description

The mechanical handling system (MHS) provides for lifting heavy loads. The MHS equipment can be operated during shutdown and refueling.

The component locations of the MHS are as shown in Table 2.3.5-3.

1. The functional arrangement of the MHS is as described in the Design Description of this Section 2.3.5.

2. The seismic Category I equipment identified in Table 2.3.5-1 can withstand seismic design basis loads without loss of safety function.

3. The MHS provides the following safety-related functions:

   g) The containment polar crane prevents the uncontrolled lowering of a heavy load.

   h) The equipment hatch hoist prevents the uncontrolled lowering of a heavy load.

4. The spent fuel shipping cask crane cannot move over the spent fuel pool.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.3.5-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the MHS.

Table 2.3.5-1				
Equipment Name	**Tag No.**	**Seismic Cat. I**	**Class 1E/ Qual. for Harsh Envir.**	**Safety Function**
Containment Polar Crane	MHS-MH-01	Yes	No/No	Avoid uncontrolled lowering of heavy load.
Equipment Hatch Hoist	MHS-MH-05	Yes	No/No	Avoid uncontrolled lowering of heavy load.

Table 2.3.5-2
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the MHS is as described in the Design Description of this Section 2.3.5.	Inspection of the as-built system will be performed.	The as-built MHS conforms with the functional arrangement as described in the Design Description of this Section 2.3.5.
2. The seismic Category I equipment identified in Table 2.3.5-1 can withstand seismic design basis loads without loss of safety function.	i) Inspection will be performed to verify that the seismic Category I equipment identified in Table 2.3.5-1 is located on the Nuclear Island.	i) The seismic Category I equipment identified in Table 2.3.5-1 is located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis loads without loss of safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) A report exists and concludes that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.
3.a) The containment polar crane prevents the uncontrolled lowering of a heavy load.	Load testing of the main and auxiliary hoists that handle heavy loads will be performed. The test load will be at least equal to the weight of the reactor vessel head and integrated head package.	The crane lifts the test load, and lowers, stops, and holds the test load with the hoist holding brakes.
3.b) The equipment hatch hoist prevents the uncontrolled lowering of a heavy load.	Testing of the redundant hoist holding mechanisms for the equipment hatch hoist that handles heavy loads will be performed by lowering the hatch at the maximum operating speed.	Each hoist holding mechanism stops and holds the hatch.
4. The spent fuel shipping cask crane cannot move over the spent fuel pool.	Testing of the spent fuel shipping cask crane is performed.	The spent fuel shipping cask crane does not move over the spent fuel pool.

Table 2.3.5-3		
Component Name	**Tag No.**	**Component Location**
Containment Polar Crane	MHS-MH-01	Containment
Equipment Hatch Hoist	MHS-MH-05	Containment
Spent Fuel Shipping Cask Crane	MHS-MH-02	Auxiliary Building

2.3.6 Normal Residual Heat Removal System

Design Description

The normal residual heat removal system (RNS) removes heat from the core and reactor coolant system (RCS) and provides RCS low temperature over-pressure (LTOP) protection at reduced RCS pressure and temperature conditions after shutdown. The RNS also provides a means for cooling the in-containment refueling water storage tank (IRWST) during normal plant operation.

The RNS is as shown in Figure 2.3.6-1 and the RNS component locations are as shown in Table 2.3.6-5.

1. The functional arrangement of the RNS is as described in the Design Description of this Section 2.3.6.

2. a) The components identified in Table 2.3.6-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.

   b) The piping identified in Table 2.3.6-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.

3. a) Pressure boundary welds in components identified in Table 2.3.6-1 as ASME Code Section III meet ASME Code Section III requirements.

   b) Pressure boundary welds in piping identified in Table 2.3.6-2 as ASME Code Section III meet ASME Code Section III requirements.

4. a) The components identified in Table 2.3.6-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.

   b) The piping identified in Table 2.3.6-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.

5. a) The seismic Category I equipment identified in Table 2.3.6-1 can withstand seismic design basis loads without loss of safety function.

   b) Each of the lines identified in Table 2.3.6-2 for which functional capability is required is designed to withstand combined normal and seismic design basis loads without a loss of its functional capability.

6. Each of the as-built lines identified in Table 2.3.6-2 as designed for leak before break (LBB) meets the LBB criteria, or an evaluation is performed of the protection from the dynamic effects of a rupture of the line.

7. a) The Class 1E equipment identified in Table 2.3.6-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.

   b) The Class 1E components identified in Table 2.3.6-1 are powered from their respective Class 1E division.

c) Separation is provided between RNS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.

8. The RNS provides the following safety-related functions:

   a) The RNS preserves containment integrity by isolation of the RNS lines penetrating the containment.

   b) The RNS provides a flow path for long-term, post-accident makeup to the RCS.

9. The RNS provides the following nonsafety-related functions:

   a) The RNS provides low temperature overpressure protection (LTOP) for the RCS during shutdown operations.

   b) The RNS provides heat removal from the reactor coolant during shutdown operations.

   c) The RNS provides low pressure makeup flow from the SFS cask loading pit to the RCS for scenarios following actuation of the automatic depressurization system (ADS).

   d) The RNS provides heat removal from the in-containment refueling water storage tank.

10. Safety-related displays identified in Table 2.3.6-1 can be retrieved in the main control room (MCR).

11. a) Controls exist in the MCR to cause those remotely operated valves identified in Table 2.3.6-1 to perform active functions.

    b) The valves identified in Table 2.3.6-1 as having protection and safety monitoring system (PMS) control perform active safety functions after receiving a signal from the PMS.

12. a) The motor-operated and check valves identified in Table 2.3.6-1 perform an active safety-related function to change position as indicated in the table.

    b) After loss of motive power, the remotely operated valves identified in Table 2.3.6-1 assume the indicated loss of motive power position.

13. Controls exist in the MCR to cause the pumps identified in Table 2.3.6-3 to perform the listed function.

14. Displays of the RNS parameters identified in Table 2.3.6-3 can be retrieved in the MCR.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.3.6-4 specifies the inspections, tests, analyses, and associated acceptance criteria for the RNS.

Table 2.3.6-1									
Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS	Active Function	Loss of Motive Power Position
RNS Pump A (Pressure Boundary)	RNS-MP-01A	Yes	Yes	-	-/-	-	-	No	-
RNS Pump B (Pressure Boundary)	RNS-MP-01B	Yes	Yes	-	-/-	-	-	No	-
RNS Heat Exchanger A (Tube Side)	RNS-ME-01A	Yes	Yes	-	-/-	-	-	-	-
RNS Heat Exchanger B (Tube Side)	RNS-ME-01B	Yes	Yes	-	-/-	-	-	-	-
RCS Inner Hot Leg Suction Motor-operated Isolation Valve	RNS-PL-V001A	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	As Is
RCS Inner Hot Leg Suction Motor-operated Isolation Valve	RNS-PL-V001B	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	As Is
RCS Outer Hot Leg Suction Motor-operated Isolation Valve	RNS-PL-V002A	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	As Is
RCS Outer Hot Leg Suction Motor-operated Isolation Valve	RNS-PL-V002B	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	As Is

Note: Dash (-) indicates not applicable.

Table 2.3.6-1 (cont.)									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS**	**Active Function**	**Loss of Motive Power Position**
RCS Pressure Boundary Thermal Relief Check Valve	RNS-PL-V003A	Yes	Yes	No	-/-	No	-	Transfer Open/ Transfer Closed	-
RCS Pressure Boundary Thermal Relief Check Valve	RNS-PL-V003B	Yes	Yes	No	-/-	No	-	Transfer Open/ Transfer Closed	-
RNS Discharge Motor-operated Containment Isolation Valve	RNS-PL-V011	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes	Transfer Open/ Transfer Closed	As Is
RNS Discharge Header Containment Isolation Check Valve	RNS-PL-V013	Yes	Yes	No	-/-	No	-	Transfer Open/ Transfer Closed	-
RNS Discharge RCS Pressure Boundary Check Valve	RNS-PL-V015A	Yes	Yes	No	-/-	No	-	Transfer Open/ Transfer Closed	-
RNS Discharge RCS Pressure Boundary Check Valve	RNS-PL-V015B	Yes	Yes	No	-/-	No	-	Transfer Open/ Transfer Closed	-

Note: Dash (-) indicates not applicable.

Table 2.3.6-1 (cont.)

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS	Active Function	Loss of Motive Power Position
RNS Discharge RCS Pressure Boundary Check Valve	RNS-PL-V017A	Yes	Yes	No	-/-	No	-	Transfer Open/ Transfer Closed	-
RNS Discharge RCS Pressure Boundary Check Valve	RNS-PL-V017B	Yes	Yes	No	-/-	No	-	Transfer Open/ Transfer Closed	-
RNS Hot Leg Suction Pressure Relief Valve	RNS-PL-V021	Yes	Yes	No	-/-	No	-	Transfer Open/ Transfer Closed	-
RNS Suction Header Motor-operated Containment Isolation Valve	RNS-PL-V022	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes	Transfer Closed	As Is
RNS Suction from IRWST Motor-operated Isolation Valve	RNS-PL-V023	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes	Transfer Closed	As Is
RNS Discharge to IRWST Motor-operated Isolation Valve	RNS-PL-V024	Yes	Yes	Yes	-/-	No	No	No	As Is

Note: Dash (-) indicates not applicable.

Table 2.3.6-1 (cont.)

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS	Active Function	Loss of Motive Power Position
RNS Discharge Header Relief Valve	RNS-PL-V045	Yes	Yes	No	-/-	No	-	Transfer Open/ Transfer Closed	-
RNS Heat Exchanger A Channel Head Drain Valve	RNS-PL-V046A	Yes	Yes	No	-/-	No	-	Transfer Open	-
RNS Heat Exchanger B Channel Head Drain Valve	RNS-PL-V046B	Yes	Yes	No	-/-	No	-	Transfer Open	-
RNS Suction from Cask Loading Pit Motor-operated Isolation Valve	RNS-PL-V055	Yes	Yes	Yes	No/No	No	No	No	As Is
RNS Suction from Cask Loading Pit Check Valve	RNS-PL-V056	Yes	Yes	No	-/-	No	-	No	-
RNS Pump Miniflow Air-Operated Isolation Valve	RNS-PL-V057A	Yes	Yes	Yes	No/No	No	No	No	Open
RNS Pump Miniflow Air-Operated Isolation Valve	RNS-PL-V057B	Yes	Yes	Yes	No/No	No	No	No	Open
RNS Return from Chemical and Volume Control System (CVS) Containment Isolation Valve	RNS-PL-V061	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes	Transfer Closed	Closed

Table 2.3.6-2				
Line Name	**Line No.**	**ASME Code Section III**	**Leak Before Break**	**Functional Capability Required**
RNS Suction Lines, from the RCS Hot Leg Connection to the RCS Side of Valves RNS PL-V001A and RNS-PL-V001B	RNS-BTA-L001 RNS-BTA-L002A RNS-BTA-L002B	Yes	Yes	No
RNS Suction Lines, from the RCS Pressure Boundary Valves, RNS-PL-V001A and RNS-PL-V001B, to the RNS pumps	RNS-BBB-L004A RNS-BBB-L004B RNS-BBB-L005 RNS-DBC-L006 RNS-DBC-L007A RNS-DBC-L007B RNS-DBC-L009A RNS-DBC-L009B	Yes	No	Yes Yes Yes No No No No No
RNS Suction Line from CVS	RNS-BBB-L061	Yes	No	No
RNS Suction Line from IRWST	RNS-BBB-L029	Yes	No	No
RNS Suction Line LTOP Relief	RNS-BBB-L040	Yes	No	Yes
RNS Discharge Lines, from the RNS Pumps to the RNS Heat Exchangers RNS-ME-01A and RNS-ME-01B	RNS-DBC-L011A RNS-DBC-L011B	Yes	No	Yes
RNS Discharge Lines, from RNS Heat Exchanger RNS-ME-01A to Containment Isolation Valve RNS-PL-V011	RNS-DBC-L012A RNS-DBC-L014	Yes	No	Yes
RNS Discharge Line, from RNS Heat Exchanger RNS-ME-01B to Common Discharge Header RNS-DBC-L014	RNS-DBC-L012B	Yes	No	Yes
RNS Discharge Lines, Containment Isolation Valve RNS-PL-V011 to Containment Isolation Valve RNS-PL-V013	RNS-BBB-L016	Yes	No	Yes

Table 2.3.6-2 (cont.)

Line Name	Line No.	ASME Code Section III	Leak Before Break	Functional Capability Required
RNS Suction Line from Cask Loading Pit	RNS-DBC-L065	Yes	No	No
RNS Discharge Lines, from Containment Isolation Valve RNS-PL-V013 to RCS Pressure Boundary Isolation Valves RNS-PL-V015A and RNS-PL-V015B	RNS-BBC-L017 RNS-BBC-L018A RNS-BBC-L018B	Yes	No	Yes
RNS Discharge Lines, from Direct Vessel Injection (DVI) Line RNS-BBC-L018A to Passive Core Cooling System (PXS) IRWST Return Isolation Valve RNS-PL-V024	RNS-BBC-L020	Yes	No	No
RNS Discharge Lines, from RCS Pressure Boundary Isolation Valves RNS-PL-V015A and RNS-PL-V015B to Reactor Vessel DVI Nozzles	RNS-BTA-L019A RNS-BTA-L019B	Yes	Yes	Yes
RNS Heat Exchanger Bypass	RNS-DBC-L008A RNS-DBC-L008B	Yes	No	No
RNS Suction from Spent Fuel Pool	RNS-DBC-L052	Yes	No	No
RNS Pump Miniflow Return	RNS-DBC-L030A RNS-DBC-L030B	Yes	No	No
RNS Discharge to Spent Fuel Pool	RNS-DBC-L051	Yes	No	No
RNS Discharge to CVS Purification	RNS-BBC-L021	Yes	No	No

Table 2.3.6-3			
Equipment Name	**Tag No.**	**Display**	**Control Function**
RNS Pump 1A (Motor)	RNS-MP-01A	Yes (Run Status)	Start
RNS Pump 1B (Motor)	RNS-MP-01B	Yes (Run Status)	Start
RNS Flow Sensor	RNS-01A	Yes	-
RNS Flow Sensor	RNS-01B	Yes	-
RNS Suction from Cask Loading Pit Isolation Valve (Position Indicator)	RNS-PL-V055	Yes	-
RNS Pump Miniflow Isolation Valve (Position Indicator)	RNS-PL-V057A	Yes	-
RNS Pump Miniflow Isolation Valve (Position Indicator)	RNS-PL-V057B	Yes	-

Note: Dash (-) indicates not applicable.

Table 2.3.6-4
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the RNS is as described in the Design Description of this Section 2.3.6.	Inspection of the as-built system will be performed.	The as-built RNS conforms with the functional arrangement described in the Design Description of this Section 2.3.6.
2.a) The components identified in Table 2.3.6-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built components as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built components identified in Table 2.3.6-1 as ASME Code Section III.
2.b) The piping identified in Table 2.3.6-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built piping as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built piping identified in Table 2.3.6-2 as ASME Code Section III.
3.a) Pressure boundary welds in components identified in Table 2.3.6-1 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
3.b) Pressure boundary welds in piping identified in Table 2.3.6-2 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
4.a) The components identified in Table 2.3.6-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.	A hydrostatic test will be performed on the components required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the components identified in Table 2.3.6-1 as ASME Code Section III conform with the requirements of the ASME Code Section III.

Table 2.3.6-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4.b) The piping identified in Table 2.3.6-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.	A hydrostatic test will be performed on the piping required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the piping identified in Table 2.3.6-2 as ASME Code Section III conform with the requirements of the ASME Code Section III.
5.a) The seismic Category I equipment identified in Table 2.3.6-1 can withstand seismic design basis loads without loss of safety function.	i) Inspection will be performed to verify that the seismic Category I equipment identified in Table 2.3.6-1 is located on the Nuclear Island.	i) The seismic Category I equipment identified in Table 2.3.6-1 is located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis loads without loss of safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) A report exists and concludes that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.
5.b) Each of the lines identified in Table 2.3.6-2 for which functional capability is required is designed to withstand combined normal and seismic design basis loads without a loss of its functional capability.	Inspection will be performed for the existence of a report verifying that the as-built piping meets the requirements for functional capability.	A report exists and concludes that each of the as-built lines identified in Table 2.3.6-2 for which functional capability is required meets the requirements for functional capability.
6. Each of the as-built lines identified in Table 2.3.6-2 as designed for LBB meets the LBB criteria, or an evaluation is performed of the protection from the dynamic effects of a rupture of the line.	Inspection will be performed for the existence of an LBB evaluation report or an evaluation report on the protection from dynamic effects of a pipe break. Tier 1 Material, Section 3.3, Nuclear Island Buildings, contains the design descriptions and inspections, tests, analyses, and acceptance criteria for protection from the dynamic effects of pipe rupture.	An LBB evaluation report exists and concludes that the LBB acceptance criteria are met by the as-built RCS piping and piping materials, or a pipe break evaluation report exists and concludes that protection from the dynamic effects of a line break is provided.

Table 2.3.6-4 (cont.) Inspections, Tests, Analyses, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
7.a) The Class 1E equipment identified in Tables 2.3.6-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.	i) Type tests, analyses, or a combination of type tests and analyses will be performed on Class 1E equipment located in a harsh environment.	i) A report exists and concludes that the Class 1E equipment identified in Table 2.3.6-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.
	ii) Inspection will be performed of the as-installed Class 1E equipment and the associated wiring, cables, and terminations located in a harsh environment.	ii) A report exists and concludes that the as-installed Class 1E equipment and the associated wiring, cables, and terminations identified in Table 2.3.6-1 as being qualified for a harsh environment are bounded by type tests, analyses, or a combination of type tests and analyses.
7.b) The Class 1E components identified in Table 2.3.6-1 are powered from their respective Class 1E division.	Testing will be performed on the RNS by providing a simulated test signal in each Class 1E division.	A simulated test signal exists at the Class 1E equipment identified in Table 2.3.6-1 when the assigned Class 1E division is provided the test signal.
7.c) Separation is provided between RNS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.	See Tier 1 Material, Table 3.3-6, item 7.d.	See Tier 1 Material, Table 3.3-6, item 7.d.
8.a) The RNS preserves containment integrity by isolation of the RNS lines penetrating the containment.	See Tier 1 Material, Table 2.2.1-3, item 7.	See Tier 1 Material, Table 2.2.1-3, item 7.
8.b) The RNS provides a flow path for long-term, post-accident makeup to the RCS.	See item 1 in this table.	See item 1 in this table.
9.a) The RNS provides LTOP for the RCS during shutdown operations.	i) Inspections will be conducted on the low temperature overpressure protection relief valve to confirm that the capacity of the vendor code plate rating is greater than or equal to system relief requirements.	i) The rated capacity recorded on the valve vendor code plate is not less than the flow required to provide low-temperature overpressure protection for the RCS, as determined by the LTOPS evaluation based on the pressure-temperature curves developed for the as-procured reactor vessel material.

Table 2.3.6-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
	ii) Testing and analysis in accordance with the ASME Code Section III will be performed to determine set pressure.	ii) A report exists and concludes that the relief valve opens at a pressure not greater than the set pressure required to provide low-temperature overpressure protection for the RCS, as determined by the LTOPS evaluation based on the pressure-temperature curves developed for the as-procured reactor vessel material.
9.b) The RNS provides heat removal from the reactor coolant during shutdown operations.	i) Inspection will be performed for the existence of a report that determines the heat removal capability of the RNS heat exchangers.	i) A report exists and concludes that the product of the overall heat transfer coefficient and the effective heat transfer area, UA, of each RNS heat exchanger is greater than or equal to 2.2 million Btu/hr-°F.
	ii) Testing will be performed to confirm that the RNS can provide flow through the RNS heat exchangers when the pump suction is aligned to the RCS hot leg and the discharge is aligned to both PXS DVI lines with the RCS at atmospheric pressure.	ii) Each RNS pump provides at least 1400 gpm net flow to the RCS when the hot leg water level is at an elevation 15.5 inches ± 2 inches above the bottom of the hot leg.
	iii) Inspection will be performed of the reactor coolant loop piping.	iii) The RCS cold legs piping centerline is 17.5 inches ± 2 inches above the hot legs piping centerline.
	iv) Inspection will be performed of the RNS pump suction piping.	iv) The RNS pump suction piping from the hot leg to the pump suction piping low point does not form a local high point (defined as an upward slope with a vertical rise greater than 3 inches).
	v) Inspection will be performed of the RNS pump suction nozzle connection to the RCS hot leg.	v) The RNS suction line connection to the RCS is constructed from 20-inch Schedule 140 pipe.

Table 2.3.6-4 (cont.) Inspections, Tests, Analyses, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
9.c) The RNS provides low pressure makeup flow from the cask loading pit to the RCS for scenarios following actuation of the ADS.	Testing will be performed to confirm that the RNS can provide low pressure makeup flow from the cask loading pit to the RCS when the pump suction is aligned to the cask loading pit and the discharge is aligned to both PXS DVI lines with RCS at atmospheric pressure.	Each RNS pump provides at least 1100 gpm net flow to the RCS when the water level above the bottom of the cask loading pit is 1 foot ± 6 inches.
9.d) The RNS provides heat removal from the in-containment refueling water storage tank (IRWST).	Testing will be performed to confirm that the RNS can provide flow through the RNS heat exchangers when the pump suction is aligned to the IRWST and the discharge is aligned to the IRWST.	Two operating RNS pumps provide at least 2000 gpm to the IRWST.
10. Safety-related displays identified in Table 2.3.6-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the safety-related displays in the MCR.	Safety-related displays identified in Table 2.3.6-1 can be retrieved in the MCR.
11.a) Controls exist in the MCR to cause those remotely operated valves identified in Table 2.3.6-1 to perform active functions.	Stroke testing will be performed on the remotely operated valves identified in Table 2.3.6-1 using the controls in the MCR.	Controls in the MCR operate to cause those remotely operated valves identified in Table 2.3.6-1 to perform active functions.
11.b) The valves identified in Table 2.3.6-1 as having PMS control perform active safety functions after receiving a signal from the PMS.	Testing will be performed using real or simulated signals into the PMS.	The valves identified in Table 2.3.6-1 as having PMS control perform the active function identified in the table after receiving a signal from the PMS.

Table 2.3.6-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
12.a) The motor-operated and check valves identified in Table 2.3.6-1 perform an active safety-related function to change position as indicated in the table.	i) Tests or type tests of motor-operated valves will be performed that demonstrate the capability of the valve to operate under its design conditions.	i) A test report exists and concludes that each motor-operated valve changes position as indicated in Table 2.3.6-1 under design conditions.
	ii) Inspection will be performed for the existence of a report verifying that the as-installed motor-operated valves are bounded by the tested conditions.	ii) A report exists and concludes that the as-installed motor-operated valves are bounded by the tested conditions.
	iii) Tests of the as-installed motor-operated valves will be performed under preoperational flow, differential pressure and temperature conditions.	iii) Each motor-operated valve changes position as indicated in Table 2.1.2-1 under preoperational test conditions.
	iv) Exercise testing of the check valves active safety functions identified in Table 2.3.6-1 will be performed under preoperational test pressure, temperature and fluid flow conditions.	iv) Each check valve changes position as indicated in Table 2.3.6-1.
12.b) After loss of motive power, the remotely operated valves identified in Table 2.3.6-1 assume the indicated loss of motive power position.	Testing of the installed valves will be performed under the conditions of loss of motive power.	Upon loss of motive power, each remotely operated valve identified in Table 2.3.6-1 assumes the indicated loss of motive power position.
13. Controls exist in the MCR to cause the pumps identified in Table 2.3.6-3 to perform the listed function.	Testing will be performed to actuate the pumps identified in Table 2.3.6-3 using controls in the MCR.	Controls in the MCR cause pumps identified in Table 2.3.6-3 to perform the listed action.
14. Displays of the RNS parameters identified in Table 2.3.6-3 can be retrieved in the MCR.	Inspection will be performed for retrievability in the MCR of the displays identified in Table 2.3.6-3.	Displays of the RNS parameters identified in Table 2.3.6-3 are retrieved in the MCR.

Table 2.3.6-5		
Component Name	**Tag No.**	**Component Location**
RNS Pump A	RNS-MP-01A	Auxiliary Building
RNS Pump B	RNS-MP-01B	Auxiliary Building
RNS Heat Exchanger A	RNS-ME-01A	Auxiliary Building
RNS Heat Exchanger B	RNS-ME-01B	Auxiliary Building

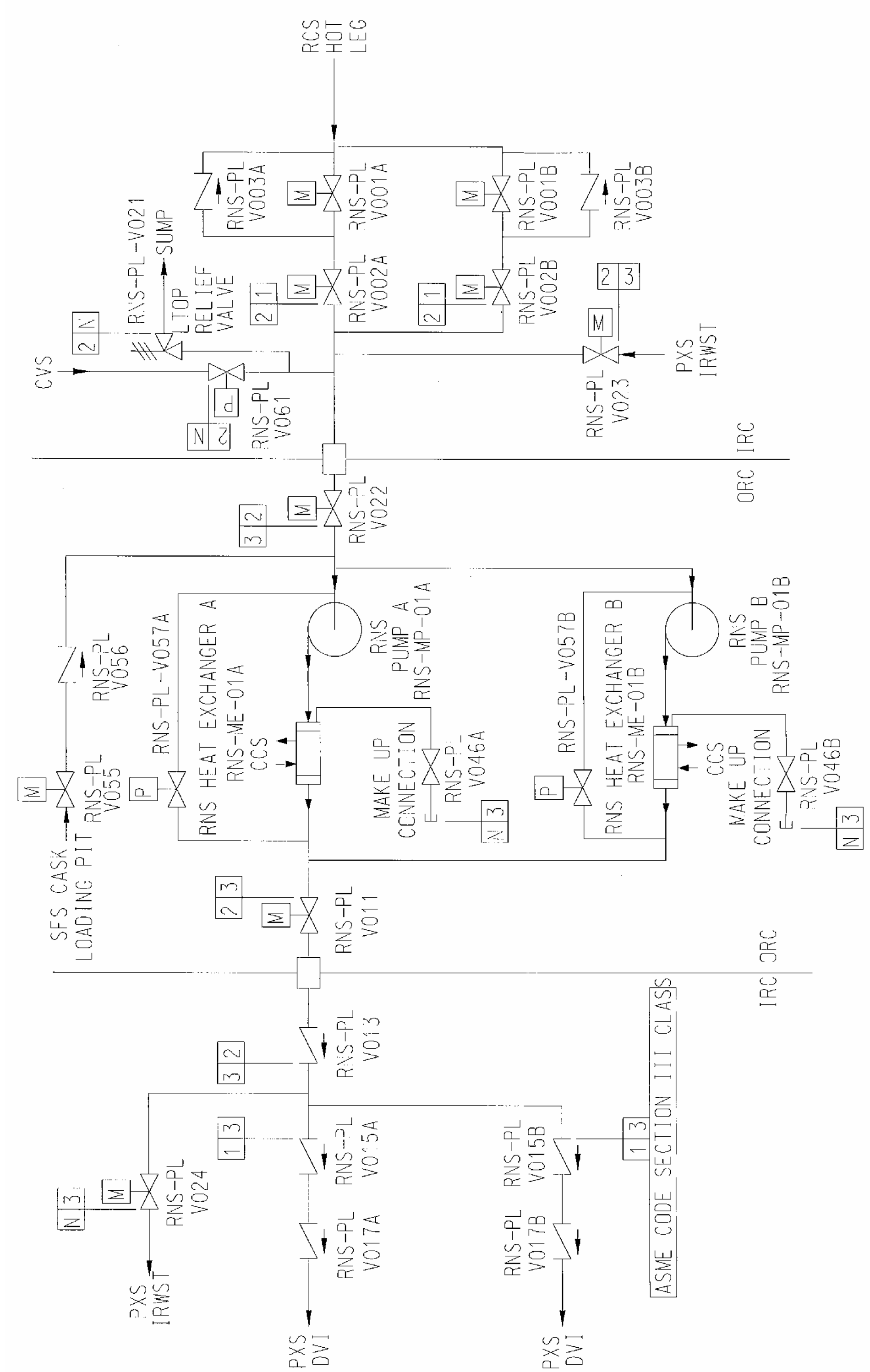


Figure 2.3.6-1
Normal Residual Heat Removal System

2.3.7 Spent Fuel Pool Cooling System

Design Description

The spent fuel pool cooling system (SFS) removes decay heat from spent fuel by transferring heat from the water in the spent fuel pool to the component cooling water system during normal modes of operation. The SFS purifies the water in the spent fuel pool, fuel transfer canal, and in-containment refueling water storage tank during normal modes of operation. Following events such as earthquakes, or fires, if the normal heat removal method is not available, decay heat is removed from spent fuel by boiling water in the pool. In the event of long-term station blackout, makeup water is supplied to the spent fuel pool from onsite storage tanks.

The SFS is as shown in Figure 2.3.7-1 and the component locations of the SFS are as shown in Table 2.3.7-5.

1. The functional arrangement of the SFS is as described in the Design Description of this Section 2.3.7.

2. a) The components identified in Table 2.3.7-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.

   b) The piping lines identified in Table 2.3.7-2 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.

3. Pressure boundary welds in piping lines identified in Table 2.3.7-2 as ASME Code Section III meet ASME Code Section III requirements.

4. The piping lines identified in Table 2.3.7-2 as ASME Code Section III retain their pressure boundary integrity at their design pressure.

5. The seismic Category I components identified in Table 2.3.7-1 can withstand seismic design basis loads without loss of safety function.

6. a) The Class 1E components identified in Table 2.3.7-1 are powered from their respective Class 1E division.

   b) Separation is provided between SFS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.

7. The SFS performs the following safety-related functions:

   a) The SFS preserves containment integrity by isolating the SFS piping lines penetrating the containment.

   b) The SFS provides spent fuel cooling for 7 days by boiling the spent fuel pool water and makeup water from on-site water storage tanks.

   c) Check valves in the drain line from the refueling cavity prevent flooding of the refueling cavity during containment flooding.

8. The SFS provides the nonsafety-related function of removing spent fuel decay heat using pumped flow through a heat exchanger.

9. Safety-related displays identified in Table 2.3.7-1 can be retrieved in the main control room (MCR).

10. Controls exist in the MCR to cause the pumps identified in Table 2.3.7-3 to perform their listed functions.

11. Displays of the SFS parameters identified in Table 2.3.7-3 can be retrieved in the MCR.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.3.7-4 specifies the inspections, tests, analyses, and associated acceptance criteria for the SFS.

Table 2.3.7-1

Component Name	Tag No.	ASME Code Section III	Seismic Cat 1	Remotely Operated Valve	Class 1E/ Qual for Harsh Envir.	Safety-Related Display	Control PMS	Active Function	Loss of Motive Power Position
Spent Fuel Pool Level Sensor	SFS-019A	No	Yes	-	Yes/No	Yes	-	-	-
Spent Fuel Pool Level Sensor	SFS-019B	No	Yes	-	Yes/No	Yes	-	-	-
Spent Fuel Pool Level Sensor	SFS-019C	No	Yes	-	Yes/No	Yes	-	-	-
Refueling Cavity Drain to SGS Compartment Isolation Valve	SFS-PL-V031	Yes	Yes	No	-/-	Yes	-	-	-
Refueling Cavity to SFS Pump Suction Isolation Valve	SFS-PL-V032	Yes	Yes	No	-/-	No	-	-	-
Refueling Cavity Drain to Containment Sump Isolation Valve	SFS-PL-V033	Yes	Yes	No	-/-	Yes	-	-	-
IRWST to SFS Pump Suction Line Isolation Valve	SFS-PL-V039	Yes	Yes	No	-/-	No	-	-	-
Fuel Transfer Canal to SFS Pump Suction Iso. Valve	SFS-PL-V040	Yes	Yes	No	-/-	No	-	-	-
Cask Loading Pit to SFS Pump Suction Isolation Valve	SFS-PL-V041	Yes	Yes	No	-/-	No	-	-	-

Note: Dash (-) indicates not applicable.

Table 2.3.7-1 (cont.)									
Component Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat 1**	**Remotely Operated Valve**	**Class 1E/ Qual for Harsh Envir.**	**Safety-Related Display**	**Control PMS**	**Active Function**	**Loss of Motive Power Position**
Cask Loading Pit to SFS Pump Suction Isolation Valve	SFS-PL-V042	Yes	Yes	No	-/-	No	-	-	-
SFS Pump Discharge Line to Cask Loading Pit Isolation Valve	SFS-PL-V045	Yes	Yes	No	-/-	No	-	-	-
Cask Loading Pit to WLS Isolation Valve	SFS-PL-V049	Yes	Yes	No	-/-	No	-	-	-
Spent Fuel Pool to Cask Washdown Pit Isolation Valve	SFS-PL-V066	Yes	Yes	No	-/-	No	-	-	-
Cask Washdown Pit Drain Isolation Valve	SFS-PL-V068	Yes	Yes	No	-/-	No	-	-	-
Refueling Cavity Drain Line Check Valve	SFS-PL-V071	Yes	Yes	No	-/-	No	-	Transfer Open Transfer Closed	-
Refueling Cavity Drain Line Check Valve	SFS-PL-V072	Yes	Yes	No	-/-	No	-	Transfer Open Transfer Closed	-

Note: Dash (-) indicates not applicable.

Table 2.3.7-2		
Piping Line Name	**Line Number**	**ASME Code Section III**
Spent Fuel Pool to RNS Pump Suction	L014	Yes
Cask Loading Pit to RNS Pump Suction	L015	Yes
Refueling Cavity Drain	L033	Yes
PXS IRWST to SFS Pump Suction	L035	Yes
Refueling Cavity Skimmer to SFS Pump Suction	L036	Yes
Refueling Cavity Drain	L037	Yes
Refueling Cavity Drain	L044	Yes
Fuel Transfer Canal Drain	L047	Yes
Cask Washdown Pit Drain	L068	Yes
Cask Loading Pit Drain	L043	Yes
Cask Pit Transfer Branch Line	L045	Yes
Refueling Cavity Drain	L030	Yes
Refueling Cavity Drain	L040	Yes
Spent Fuel Pool Drain	L066	Yes
Cask Loading Pit to WLS	L067	Yes
RNS Return to Spent Fuel Pool	L100	Yes

Table 2.3.7-3			
Component Name	**Tag No.**	**Display**	**Control Function**
SFS Pump 1A	SFS-MP-01A	Yes (Run Status)	Start
SFS Pump 1B	SFS-MP-01B	Yes (Run Status)	Start
SFS Flow Sensor	SFS-13A	Yes	-
SFS Flow Sensor	SFS-13B	Yes	-
Spent Fuel Pool Temperature Sensor	SFS-018	Yes	-
Cask Loading Pit Level Sensor	SFS-022	Yes	-

Note: Dash (-) indicates not applicable.

Table 2.3.7-4
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the SFS is as described in the Design Description of this Section 2.3.7.	Inspection of the as-built system will be performed.	The as-built SFS conforms with the functional arrangement as described in the Design Description of this Section 2.3.7.
2.a) The components identified in Table 2.3.7-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the ASME as-built components as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built components identified in Table 2.3.7-1 as ASME Code Section III.
2.b) The piping lines identified in Table 2.3.7-2 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built piping lines as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built piping lines identified in Table 2.3.7-2 as ASME Code Section III.
3. Pressure boundary welds in piping lines identified in Table 2.3.7-2 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
4. The piping lines identified in Table 2.3.7-2 as ASME Code Section III retain their pressure boundary integrity at their design pressure.	A hydrostatic test will be performed on the piping lines required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the piping lines identified in Table 2.3.7-2 as ASME Code Section III conform with the requirements of the ASME Code Section III.

Table 2.3.7-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. The seismic Category I components identified in Table 2.3.7-1 can withstand seismic design basis loads without loss of safety functions.	i) Inspection will be performed to verify that the seismic Category I components identified in Table 2.3.7-1 are located on the Nuclear Island.	i) The seismic Category I components identified in Table 2.3.7-1 are located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis loads without loss of safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) A report exists and concludes that the as-built equipment including anchorage is seismically bounded by the tested or analyzed conditions.
6.a) The Class 1E components identified in Table 2.3.7-1 are powered from their respective Class 1E division.	Testing will be performed on the SFS by providing a simulated test signal in each Class 1E division.	A simulated test signal exists at the Class 1E components identified in Table 2.3.7-1 when the assigned Class 1E division is provided the test signal.
6.b) Separation is provided between SFS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.	See Tier 1 Material, Table 3.3-6, item 7.d.	See Tier 1 Material, Table 3.3-6, item 7.d.
7.a) The SFS preserves containment integrity by isolation of the SFS lines penetrating the containment.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.

Table 2.3.7-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7.b) The SFS provides spent fuel cooling for 7 days by boiling the spent fuel pool water and makeup water from on-site storage tanks.	i) Inspection will be performed to verify that the spent fuel pool includes a sufficient volume of water.	i) The volume of the spent fuel pool and fuel transfer canal above the fuel and to the elevation 6 feet below the operating deck is greater than or equal to 46,700 gallons.
	ii) Inspection will be performed to verify the cask washdown pit includes sufficient volume of water.	ii) The water volume of the cask washdown pit is greater than or equal to 30,900 gallons.
	iii) A safety-related flow path exists from the cask washdown pit to the spent fuel pool.	iii) See item 1 of this table.
	iv) See Tier 1 Material Table 2.2.2-3, item 7.f for inspection, testing, and acceptance criteria for the makeup water supply from the passive containment cooling system (PCS) water storage tank to the spent fuel pool.	iv) See Tier 1 Material Table 2.2.2-3, item 7.f for inspection, testing, and acceptance criteria for the makeup water supply from the PCS water storage tank to the spent fuel pool.
	v) Inspection will be performed to verify that the passive containment cooling system water storage tank includes a sufficient volume of water.	v) See Tier 1 Material Table 2.2.2-3, item 7.f for the volume of the passive containment cooling system water storage tank.
	vi) See Tier 1 Material Table 2.2.2-3, items 8.a and 8.b for inspection, testing, and acceptance criteria to verify that the passive containment cooling system ancillary water storage tank includes a sufficient volume of water.	vi) See Tier 1 Material Table 2.2.2-3, items 8.a and 8.b for inspection, testing, and acceptance criteria for the volume of the passive containment cooling system ancillary water storage tank.

Table 2.3.7-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
8. The SFS provides the nonsafety-related function of removing spent fuel decay heat using pumped flow through a heat exchanger.	i) Inspection will be performed for the existence of a report that determines the heat removal capability of the SFS heat exchangers.	i) A report exists and concludes that the heat transfer characteristic, UA, of each SFS heat exchanger is greater than or equal to 2.2 million Btu/hr-°F.
	ii) Testing will be performed to confirm that each SFS pump provides flow through its heat exchanger when taking suction from the SFP and returning flow to the SFP.	ii) Each SFS pump produces at least 900 gpm through its heat exchanger.
9. Safety-related displays identified in Table 2.3.7-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the safety-related displays in the MCR.	Safety-related displays identified in Table 2.3.7-1 can be retrieved in the MCR.
10. Controls exist in the MCR to cause the pumps identified in Table 2.3.7-3 to perform their listed functions.	Testing will be performed to actuate the pumps identified in Table 2.3.7-3 using controls in the MCR.	Controls in the MCR cause pumps identified in Table 2.3.7-3 to perform the listed functions.
11. Displays of the SFS parameters identified in Table 2.3.7-3 can be retrieved in the MCR.	Inspection will be performed for retrievability in the MCR of the displays identified in Table 2.3.7-3.	Displays of the SFS parameters identified in Table 2.3.7-3 are retrieved in the MCR.
12. The check valves in the drain lines from the refueling cavity (Table 2.3.7-1) perform an active safety-related function to change position as indicated in the table.	Exercise testing of the check valves with active safety-functions identified in Table 2.3.7-1 will be performed under pre-operational test pressure, temperature and flow conditions.	Each check valve changes position as indicated on Table 2.3.7-1.

Table 2.3.7-5		
Component Name	**Tag No.**	**Component Location**
SFS Pump A	SFS-MP-01A	Auxiliary Building
SFS Pump B	SFS-MP-01B	Auxiliary Building
SFS Heat Exchanger A	SFS-ME-01A	Auxiliary Building
SFS Heat Exchanger B	SFS-ME-01B	Auxiliary Building

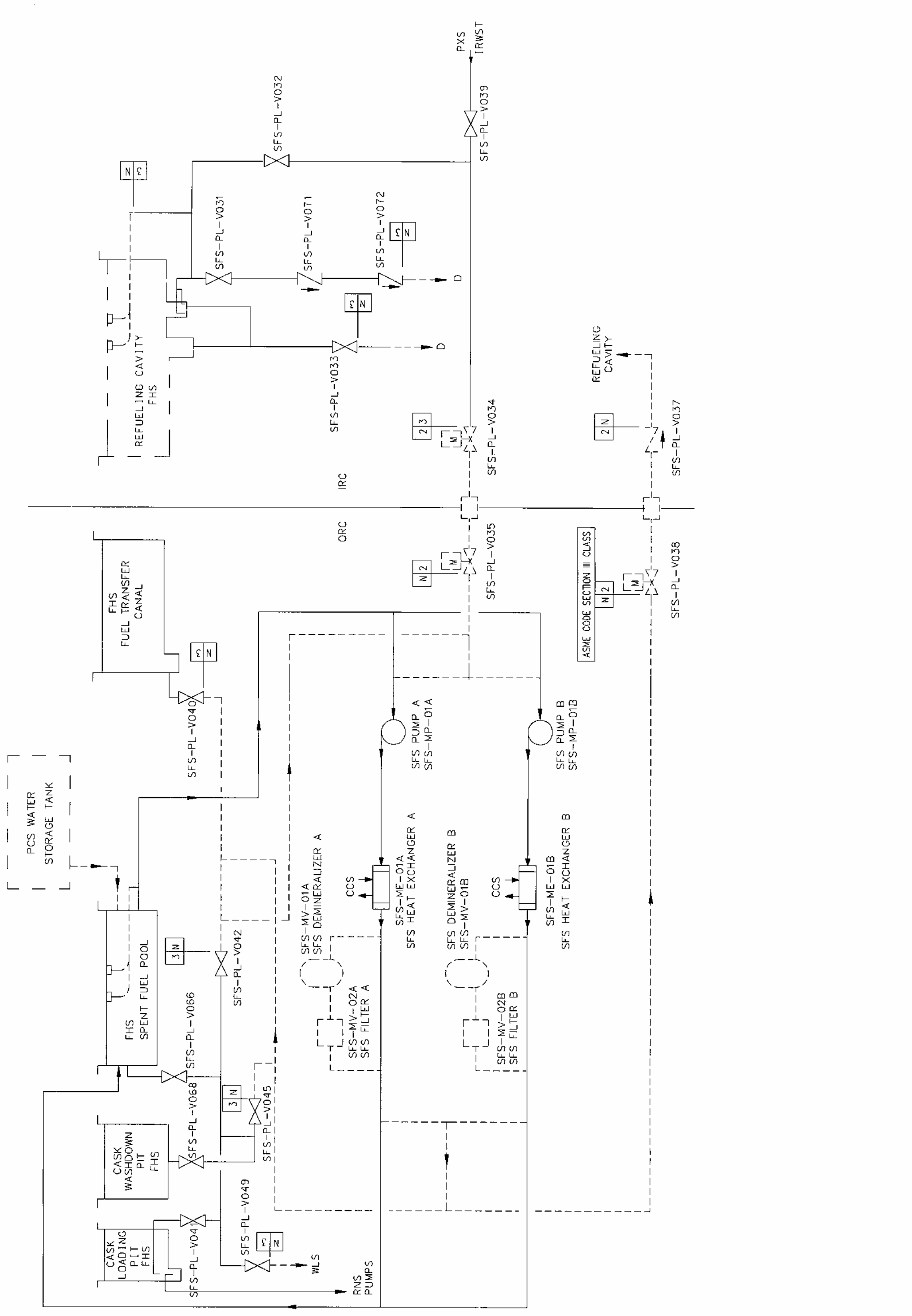


Figure 2.3.7-1
Spent Fuel Pool Cooling System

2.3.8 Service Water System

Design Description

The service water system (SWS) transfers heat from the component cooling water heat exchangers to the atmosphere. The SWS operates during normal modes of plant operation, including startup, power operation (full and partial loads), cooldown, shutdown, and refueling.

The SWS is as shown in Figure 2.3.8-1 and the component locations of the SWS are as shown Table 2.3.8-3.

1. The functional arrangement of the SWS is as described in the Design Description of this Section 2.3.8.

2. The SWS provides the nonsafety-related function of transferring heat from the component cooling water system (CCS) to the surrounding atmosphere to support plant shutdown and spent fuel pool cooling.

3. Controls exist in the main control room (MCR) to cause the components identified in Table 2.3.8-1 to perform the listed function.

4. Displays of the parameters identified in Table 2.3.8-1 can be retrieved in the MCR.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.3.8-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the SWS.

Table 2.3.8-1			
Equipment Name	**Tag No.**	**Display**	**Control Function**
Service Water Pump A (Motor)	SWS-MP-01A	Yes (Run Status)	Start
Service Water Pump B (Motor)	SWS-MP-01B	Yes (Run Status)	Start
Service Water Cooling Tower Fan A (Motor)	SWS-MA-01A	Yes (Run Status)	Start
Service Water Cooling Tower Fan B (Motor)	SWS-MA-01A	Yes (Run Status)	Start
Service Water Pump 1A Flow Sensor	SWS-004A	Yes	-
Service Water Pump 1B Flow Sensor	SWS-004B	Yes	-
Service Water Pump A Discharge Valve	SWS-PL-V002A	Yes (Valve Position)	Open
Service Water Pump B Discharge Valve	SWS-PL-V002B	Yes (Valve Position)	Open
Service Water Pump A Discharge Temperature Sensor	SWS-005A	Yes	-
Service Water Pump B Discharge Temperature Sensor	SWS-005B	Yes	-

Note: Dash (-) indicates not applicable.

Table 2.3.8-2
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the SWS is as described in the Design Description of this Section 2.3.8.	Inspection of the as-built system will be performed.	The as-built SWS conforms with the functional arrangement as described in the Design Description of this Section 2.3.8.
2. The SWS provides the nonsafety-related function of transferring heat from the component cooling water system to the surrounding atmosphere to support plant shutdown and spent fuel pool cooling.	i) Testing will be performed to confirm that the SWS can provide cooling water to the CCS heat exchangers. ii) Inspection will be performed for the existence of a report that determines the heat transfer capability of each cooling tower cell.	i) Each SWS pump can provide at least 7200 gpm of cooling water through its CCS heat exchanger. ii) A report exists and concludes that the heat transfer rate of each cooling tower cell is greater than or equal to 120 million Btu/hr at a 80°F ambient wet bulb temperature and a cold water temperature of 100°F.
3. Controls exist in the MCR to cause the components identified in Table 2.3.8-1 to perform the listed function.	Testing will be performed on the components in Table 2.3.8-1 using controls in the MCR.	Controls in the MCR operate to cause the components listed in Table 2.3.8-1 to perform the listed functions.
4. Displays of the parameters identified in Table 2.3.8-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of parameters in the MCR.	The displays identified in Table 2.3.8-1 can be retrieved in the MCR.

Table 2.3.8-3		
Component Name	**Tag No.**	**Component Location**
Service Water Pump A	SWS-MP-01A	Turbine Building or yard
Service Water Pump B	SWS-MP-01B	Turbine Building or yard
Service Water Cooling Tower	SWS-ME-01	Yard

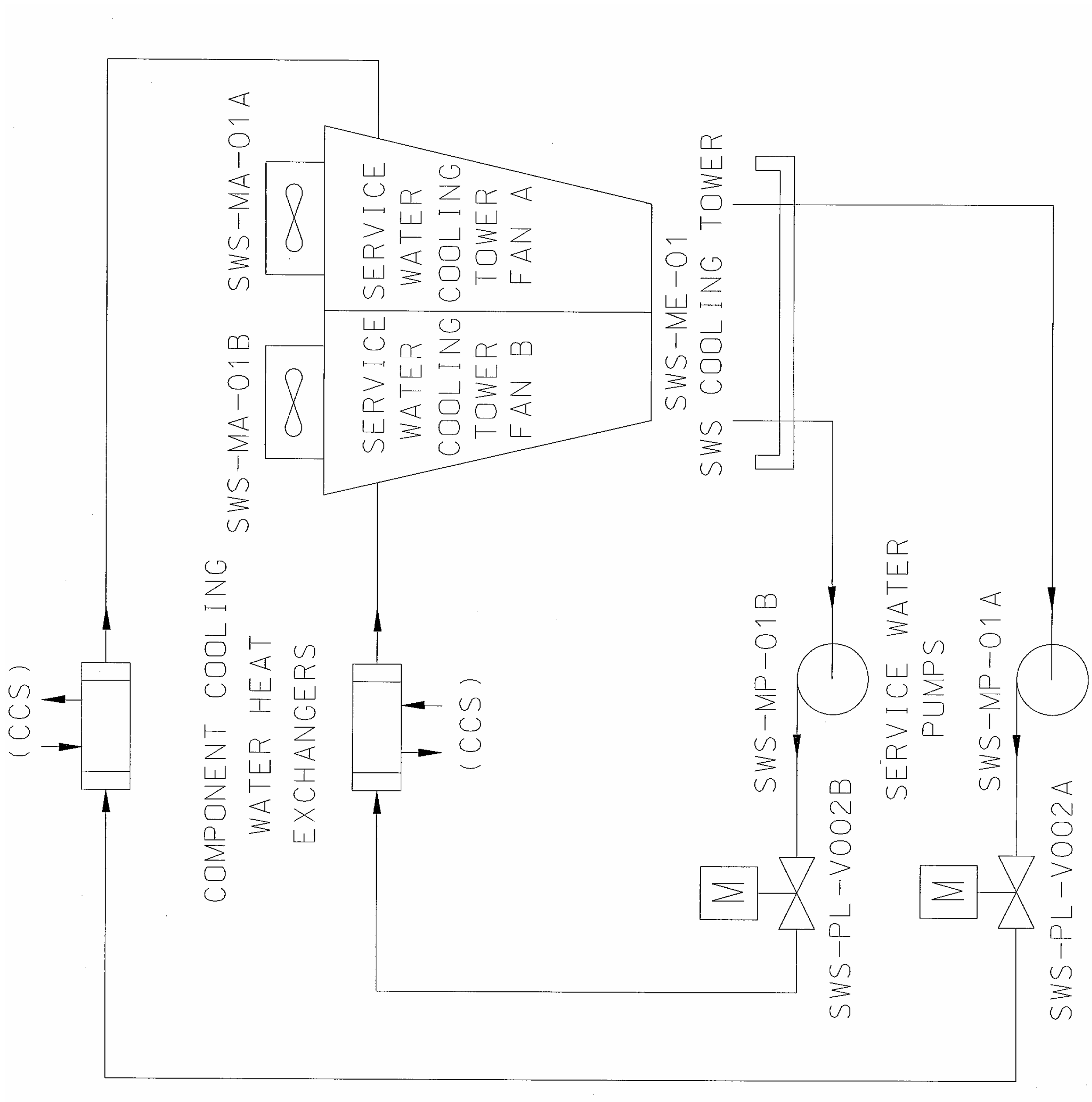


Figure 2.3.8-1
Service Water System

2.3.9 Containment Hydrogen Control System

Design Description

The containment hydrogen control system (VLS) limits hydrogen gas concentration in containment during accidents.

The VLS has catalytic hydrogen recombiners (VLS-MY-E01A and VLS-MY-E01B) that are located inside containment. The VLS has hydrogen igniters located as shown on Table 2.3.9-2.

1. The functional arrangement of the VLS is as described in the Design Description of this Section 2.3.9.

2. a) The hydrogen monitors identified in Table 2.3.9-1 are powered by the non-Class 1E dc and UPS system.

   b) The components identified in Table 2.3.9-2 are powered from their respective non-Class 1E power group.

3. The VLS provides the non-safety related function to control the containment hydrogen concentration for beyond design basis accidents.

4. a) Controls exist in the MCR to cause the components identified in Table 2.3.9-2 to perform the listed function.

   b) The components identified in Table 2.3.9-2 perform the listed function after receiving a manual signal from the diverse actuation system (DAS).

5. Displays of the parameters identified in Table 2.3.9-1 can be retrieved in the MCR.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.3.9-3 specifies the inspections, tests, analyses, and associated acceptance criteria for the VLS.

Table 2.3.9-1		
Equipment	**Tag No.**	**Display**
Containment Hydrogen Monitor	VLS-001	Yes
Containment Hydrogen Monitor	VLS-002	Yes
Containment Hydrogen Monitor	VLS-003	Yes

Table 2.3.9-2					
Equipment Name	Tag Number	Function	Power Group Number	Location	Room No.
Hydrogen Igniter 01	VLS-EH-01	Energize	1	Tunnel connection loop compartments	11204
Hydrogen Igniter 02	VLS-EH-02	Energize	2	Tunnel connection loop compartments	11204
Hydrogen Igniter 03	VLS-EH-03	Energize	1	Tunnel connection loop compartments	11204
Hydrogen Igniter 04	VLS-EH-04	Energize	2	Tunnel connection loop compartments	11204
Hydrogen Igniter 05	VLS-EH-05	Energize	1	Loop compartment 02	11402
Hydrogen Igniter 06	VLS-EH-06	Energize	2	Loop compartment 02	11502
Hydrogen Igniter 07	VLS-EH-07	Energize	2	Loop compartment 02	11402
Hydrogen Igniter 08	VLS-EH-08	Energize	1	Loop compartment 02	11502
Hydrogen Igniter 09	VLS-EH-09	Energize	1	In-containment refueling water storage tank (IRWST)	11305
Hydrogen Igniter 10	VLS-EH-10	Energize	2	IRWST	11305
Hydrogen Igniter 11	VLS-EH-11	Energize	2	Loop compartment 01	11401
Hydrogen Igniter 12	VLS-EH-12	Energize	1	Loop compartment 01	11501
Hydrogen Igniter 13	VLS-EH-13	Energize	1	Loop compartment 01	11401
Hydrogen Igniter 14	VLS-EH-14	Energize	2	Loop compartment 01	11501
Hydrogen Igniter 15	VLS-EH-15	Energize	2	IRWST	11305
Hydrogen Igniter 16	VLS-EH-16	Energize	1	IRWST	11305
Hydrogen Igniter 17	VLS-EH-17	Energize	2	Northeast valve room	11207
Hydrogen Igniter 18	VLS-EH-18	Energize	1	Northeast accumulator room	11207
Hydrogen Igniter 19	VLS-EH-19	Energize	2	East valve room	11208
Hydrogen Igniter 20	VLS-EH-20	Energize	2	Southeast accumulator room	11206
Hydrogen Igniter 21	VLS-EH-21	Energize	1	Southeast valve room	11206
Hydrogen Igniter 22	VLS-EH-22	Energize	1	Lower compartment area (core makeup tank [CMT] and valve area)	11400
Hydrogen Igniter 23	VLS-EH-23	Energize	2	Lower compartment area (CMT and valve area)	11400
Hydrogen Igniter 24	VLS-EH-24	Energize	2	Lower compartment area (CMT and valve area)	11400

Table 2.3.9-2 (cont.)					
Equipment Name	Tag Number	Function	Power Group Number	Location	Room No.
Hydrogen Igniter 25	VLS-EH-25	Energize	2	Lower compartment area (CMT and valve area)	11400
Hydrogen Igniter 26	VLS-EH-26	Energize	2	Lower compartment area (CMT and valve area)	11400
Hydrogen Igniter 27	VLS-EH-27	Energize	1	Lower compartment area (CMT and valve area)	11400
Hydrogen Igniter 28	VLS-EH-28	Energize	1	Lower compartment area (CMT and valve area)	11400
Hydrogen Igniter 29	VLS-EH-29	Energize	1	Lower compartment area (CMT and valve area)	11400
Hydrogen Igniter 30	VLS-EH-30	Energize	2	Lower compartment area (CMT and valve area)	11400
Hydrogen Igniter 31	VLS-EH-31	Energize	1	Lower compartment area (CMT and valve area)	11400
Hydrogen Igniter 32	VLS-EH-32	Energize	1	Lower compartment area (CMT and valve area)	11400
Hydrogen Igniter 33	VLS-EH-33	Energize	2	North CVS equipment room	11209
Hydrogen Igniter 34	VLS-EH-34	Energize	1	North CVS equipment room	11209
Hydrogen Igniter 35	VLS-EH-35	Energize	1	IRWST	11305
Hydrogen Igniter 36	VLS-EH-36	Energize	2	IRWST	11305
Hydrogen Igniter 37	VLS-EH-37	Energize	1	IRWST	11305
Hydrogen Igniter 38	VLS-EH-38	Energize	2	IRWST	11305
Hydrogen Igniter 39	VLS-EH-39	Energize	1	Upper compartment lower region	11500
Hydrogen Igniter 40	VLS-EH-40	Energize	2	Upper compartment lower region	11500
Hydrogen Igniter 41	VLS-EH-41	Energize	2	Upper compartment lower region	11500
Hydrogen Igniter 42	VLS-EH-42	Energize	1	Upper compartment lower region	11500
Hydrogen Igniter 43	VLS-EH-43	Energize	1	Upper compartment lower region	11500
Hydrogen Igniter 44	VLS-EH-44	Energize	1	Upper compartment lower region	11500
Hydrogen Igniter 45	VLS-EH-45	Energize	2	Upper compartment lower region	11500
Hydrogen Igniter 46	VLS-EH-46	Energize	2	Upper compartment lower region	11500

Table 2.3.9-2 (cont.)					
Equipment Name	Tag Number	Function	Power Group Number	Location	Room No.
Hydrogen Igniter 47	VLS-EH-47	Energize	1	Upper compartment lower region	11500
Hydrogen Igniter 48	VLS-EH-48	Energize	2	Upper compartment lower region	11500
Hydrogen Igniter 49	VLS-EH-49	Energize	1	Pressurizer compartment	11503
Hydrogen Igniter 50	VLS-EH-50	Energize	2	Pressurizer compartment	11503
Hydrogen Igniter 51	VLS-EH-51	Energize	1	Upper compartment mid-region	11500
Hydrogen Igniter 52	VLS-EH-52	Energize	2	Upper compartment mid-region	11500
Hydrogen Igniter 53	VLS-EH-53	Energize	2	Upper compartment mid-region	11500
Hydrogen Igniter 54	VLS-EH-54	Energize	1	Upper compartment mid-region	11500
Hydrogen Igniter 55	VLS-EH-55	Energize	1	Refueling cavity	11504
Hydrogen Igniter 56	VLS-EH-56	Energize	2	Refueling cavity	11504
Hydrogen Igniter 57	VLS-EH-57	Energize	2	Refueling cavity	11504
Hydrogen Igniter 58	VLS-EH-58	Energize	1	Refueling cavity	11504
Hydrogen Igniter 59	VLS-EH-59	Energize	2	Pressurizer compartment	11503
Hydrogen Igniter 60	VLS-EH-60	Energize	1	Pressurizer compartment	11503
Hydrogen Igniter 61	VLS-EH-61	Energize	1	Upper compartment-upper region	11500
Hydrogen Igniter 62	VLS-EH-62	Energize	2	Upper compartment-upper region	11500
Hydrogen Igniter 63	VLS-EH-63	Energize	1	Upper compartment-upper region	11500
Hydrogen Igniter 64	VLS-EH-64	Energize	2	Upper compartment-upper region	11500

Table 2.3.9-3
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the VLS is as described in the Design Description of this Section 2.3.9.	Inspection of the as-built system will be performed.	The as-built VLS conforms with the functional arrangement as described in the Design Description of this Section 2.3.9.
2.a) The hydrogen monitors identified in Table 2.3.9-1 are powered by the non-Class 1E dc and UPS system.	Testing will be performed by providing a simulated test signal in each power group of the non-Class 1E dc and UPS system.	A simulated test signal exists at the hydrogen monitors identified in Table 2.3.9-1 when the non-Class 1E dc and UPS system is provided the test signal.
2.b) The components identified in Table 2.3.9-2 are powered from their respective non-Class 1E power group.	Testing will be performed by providing a simulated test signal in each non-Class 1E power group.	A simulated test signal exists at the equipment identified in Table 2.3.9-2 when the assigned non-Class 1E power group is provided the test signal.
3. The VLS provides the nonsafety-related function to control the containment hydrogen concentration for beyond design basis accidents.	i) Inspection for the number of igniters will be performed.	i) At least 64 hydrogen igniters are provided inside containment at the locations specified in Table 2.3.9-2.
	ii) Operability testing will be performed on the igniters.	ii) The surface temperature of the igniter exceeds 1700°F.
	iii) An inspection of the as-built containment internal structures will be performed.	iii) The minimum distance between the primary openings through the ceilings of the passive core cooling system valve/accumulator rooms (11206, 11207) and the containment shell is at least 19 feet. Primary openings are those that constitute 98% of the opening area. Other openings through the ceilings of these rooms must be at least 3 feet from the containment shell.
	iv) An inspection will be performed of the as-built IRWST vents that are located in the roof of the IRWST along the side of the IRWST next to the containment shell.	iv) The discharge from each of these IRWST vents is oriented generally away from the containment shell.
4.a) Controls exist in the MCR to cause the components identified in Table 2.3.9-2 to perform the listed function.	Testing will be performed on the igniters using the controls in the MCR.	Controls in the MCR operate to energize the igniters.

Table 2.3.9-3 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4.b) The components identified in Table 2.3.9-2 perform the listed function after receiving manual a signal from DAS.	Testing will be performed on the igniters using the DAS controls.	The igniters energize after receiving a signal from DAS.
5. Displays of the parameters identified in Table 2.3.9-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the displays identified in Table 2.3.9-1 in the MCR.	Displays identified in Table 2.3.9-1 can be retrieved in the MCR.

2.3.10 Liquid Radwaste System

Design Description

The liquid radwaste system (WLS) receives, stores, processes, samples and monitors the discharge of radioactive wastewater.

The WLS has components which receive and store radioactive or potentially radioactive liquid waste. These are the reactor coolant drain tank, the containment sump, the effluent holdup tanks and the waste holdup tanks. The WLS components store and process the waste during normal operation and during anticipated operational occurrences. Monitoring of the liquid waste is performed prior to discharge.

The WLS is as shown in Figure 2.3.10-1 and the component locations of the WLS are as shown in Table 2.3.10-5.

1. The functional arrangement of the WLS is as described in the Design Description of this Section 2.3.10.

2. a) The components identified in Table 2.3.10-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.

   b) The piping identified in Table 2.3.10-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.

3. a) Pressure boundary welds in components identified in Table 2.3.10-1 as ASME Code Section III meet ASME Code Section III requirements.

   b) Pressure boundary welds in piping identified in Table 2.3.10-2 as ASME Code Section III meet ASME Code Section III requirements.

4. a) The components identified in Table 2.3.10-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.

   b) The piping identified in Table 2.3.10-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.

5. a) The seismic Category I equipment identified in Table 2.3.10-1 can withstand seismic design basis loads without loss of safety function.

   b) Each of the lines identified in Table 2.3.10-2 for which functional capability is required is designed to withstand combined normal and seismic design basis loads without a loss of its functional capability.

6. The WLS provides the following safety-related functions:

   a) The WLS preserves containment integrity by isolation of the WLS lines penetrating the containment.

   b) Check valves in drain lines to the containment sump limit cross flooding of compartments.

7. The WLS provides the nonsafety-related functions of:

   a) Detecting leaks within containment to the containment sump.

   b) Controlling releases of radioactive materials in liquid effluents.

8. Controls exist in the main control room (MCR) to cause the remotely operated valve identified in Table 2.3.10-3 to perform its active function.

9. The check valves identified in Table 2.3.10-1 perform an active safety-related function to change position as indicated in the table.

10. Displays of the parameters identified in Table 2.3.10-3 can be retrieved in the MCR.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.3.10-4 specifies the inspections, tests, analyses, and associated acceptance criteria for the WLS.

Table 2.3.10-1

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Active Function
WLS Containment Sump Level Sensor	WLS-LT-034	No	Yes	No	No/No	No	-
WLS Containment Sump Level Sensor	WLS-LT-035	No	Yes	No	No/No	No	-
WLS Containment Sump Level Sensor	WLS-LT-036	No	Yes	No	No/No	No	-
WLS Drain from Passive Core Cooling System (PXS) Compartment A (Room 11206) Check Valve	WLS-PL-V071B	Yes	Yes	No	-/-	No	Transfer Closed
WLS Drain from PXS Compartment A (Room 11206) Check Valve	WLS-PL-V072B	Yes	Yes	No	-/-	No	Transfer Closed
WLS Drain from PXS Compartment B (Room 11207) Check Valve	WLS-PL-V071C	Yes	Yes	No	-/-	No	Transfer Closed
WLS Drain from PXS Compartment B (Room 11207) Check Valve	WLS-PL-V072C	Yes	Yes	No	-/-	No	Transfer Closed
WLS Drain from Chemical and Volume Control System (CVS) Compartment (Room 11209) Check Valve	WLS-PL-V071A	Yes	Yes	No	-/-	No	Transfer Closed
WLS Drain from CVS Compartment (Room 11209) Check Valve	WLS-PL-V072A	Yes	Yes	No	-/-	No	Transfer Closed

Note: Dash (-) indicates not applicable.

Table 2.3.10-2			
Line Name	**Line No.**	**ASME Section III**	**Functional Capability Required**
WLS Drain from PXS Compartment A	WLS-PL-L062 WLS-PL-L078	Yes	Yes
WLS Drain from PXS Compartment B	WLS-PL-L063 WLS-PL-L079	Yes	Yes
WLS Drain from CVS Compartment	WLS-PL-L061 WSL-PL-L077 WLS-PL-L020	Yes	Yes

Table 2.3.10-3			
Equipment Name	**Tag No.**	**Display**	**Control Function**
WLS Effluent Discharge Isolation Valve	WLS-PL-V223	-	Close
Reactor Coolant Drain Tank Level	WLS-LT-002	Yes	-

Table 2.3.10-4
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the WLS is as described in the Design Description of this Section 2.3.10.	Inspection of the as-built system will be performed.	The as-built WLS conforms with the functional arrangement as described in the Design Description of this Section 2.3.10.
2.a) The components identified in Table 2.3.10-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built components as documented in the ASME design reports.	The ASME Code Section III design report exists for the as built components identified in Table 2.3.10-1 as ASME Code Section III.
2.b) The piping identified in Table 2.3.10-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built piping as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built piping identified in Table 2.3.10-2 as ASME Code Section III.
3.a) Pressure boundary welds in components identified in Table 2.3.10-1 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
3.b) Pressure boundary welds in piping identified in Table 2.3.10-2 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
4.a) The components identified in Table 2.3.10-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.	A hydrostatic test will be performed on the components required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the components identified in Table 2.3.10-1 as ASME Code Section III conform with the requirements of the ASME Code Section III.
4.b) The piping identified in Table 2.3.10-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.	A hydrostatic test will be performed on the piping required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the piping identified in Table 2.3.10-2 as ASME Code Section III conform with the requirements of the ASME Code Section III.

Table 2.3.10-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5.a) The seismic Category I equipment identified in Table 2.3.10-1 can withstand seismic design basis loads without loss of safety function.	i) Inspection will be performed to verify that the seismic Category I equipment identified in Table 2.3.10-1 is located on the Nuclear Island.	i) The seismic Category I equipment identified in Table 2.3.10-1 is located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis loads without loss of safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) A report exists and concludes that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.
5.b) Each of the lines identified in Table 2.3.10-2 for which functional capability is required is designed to withstand combined normal and seismic design basis loads without a loss of its functional capability.	Inspection will be performed for the existence of a report verifying that the as-built piping meets the requirements for functional capability.	A report exists and concludes that each of the as-built lines identified in Table 2.3.10-2 for which functional capability is required meets the requirements for functional capability.
6.a) The WLS preserves containment integrity by isolation of the WLS lines penetrating the containment.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.
6.b) Check valves in drain lines to the containment sump limit cross flooding of compartments.	Refer to item 9 in this table.	Refer to item 9 in this table.

Table 2.3.10-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7.a) The WLS provides the nonsafety-related function of detecting leaks within containment to the containment sump.	i) Inspection will be performed for retrievability of the displays of containment sump level channels WLS-LT-034, WLS-LT-035, and WLS-LT-036 in the MCR. ii) Testing will be performed by adding water to the sump and observing display of sump level.	i) Nonsafety-related displays of WLS containment sump level channels WLS-LT-034, WLS-LT-035, and WLS-LT-036 can be retrieved in the MCR. ii) A report exists and concludes that sump level channels WLS-LT-034, WLS-LT-035, and WLS-LT-036 can detect a change of 1.75 ± 0.1 inches.
7.b) The WLS provides the nonsafety-related function of controlling releases of radioactive materials in liquid effluents.	Tests will be performed to confirm that a simulated high radiation signal from the discharge radiation monitor, WLS-RE-229, causes the discharge isolation valve WLS-PL-V223 to close.	A simulated high radiation signal causes the discharge control isolation valve WLS-PL-V223 to close.
8. Controls exist in the MCR to cause the remotely operated valve identified in Table 2.3.10-3 to perform its active function.	Stroke testing will be performed on the remotely operated valve listed in Table 2.3.10-3 using controls in the MCR.	Controls in the MCR operate to cause the remotely operated valve to perform its active function.
9. The check valves identified in Table 2.3.10-1 perform an active safety-related function to change position as indicated in the table.	Exercise testing of the check valves with active safety functions identified in Table 2.3.10-1 will be performed under pre-operational test pressure, temperature and flow conditions.	Each check valve changes position as indicated on Table 2.3.10-1.
10. Displays of the parameters identified in Table 2.3.10-3 can be retrieved in the MCR.	Inspection will be performed for retrievability of the displays identified in Table 2.3.10-3 in the MCR.	Displays identified in Table 2.3.10-3 can be retrieved in the MCR.

Table 2.3.10-5		
Component Name	**Tag No.**	**Component Location**
WLS Reactor Coolant Drain Tank	WLS-MT-01	Containment
WLS Containment Sump	WLS-MT-02	Containment
WLS Degasifier Column	WLS-MV-01	Auxiliary Building
WLS Effluent Holdup Tanks	WLS-MT-05A WLS-MT-05B	Auxiliary Building
WLS Waste Holdup Tanks	WLS-MT-06A WLS-MT-06B	Auxiliary Building
WLS Waste Pre-Filter	WLS-MV-06	Auxiliary Building
WLS Ion Exchangers	WLS-MV-03 WLS-MV-04A WLS-MV-04B WLS-MV-04C	Auxiliary Building
WLS Waste After-Filter	WLS-MV-07	Auxiliary Building
WLS Monitor Tanks	WLS-MT-07A WLS-MT-07B WLS-MT-07C	Auxiliary Building

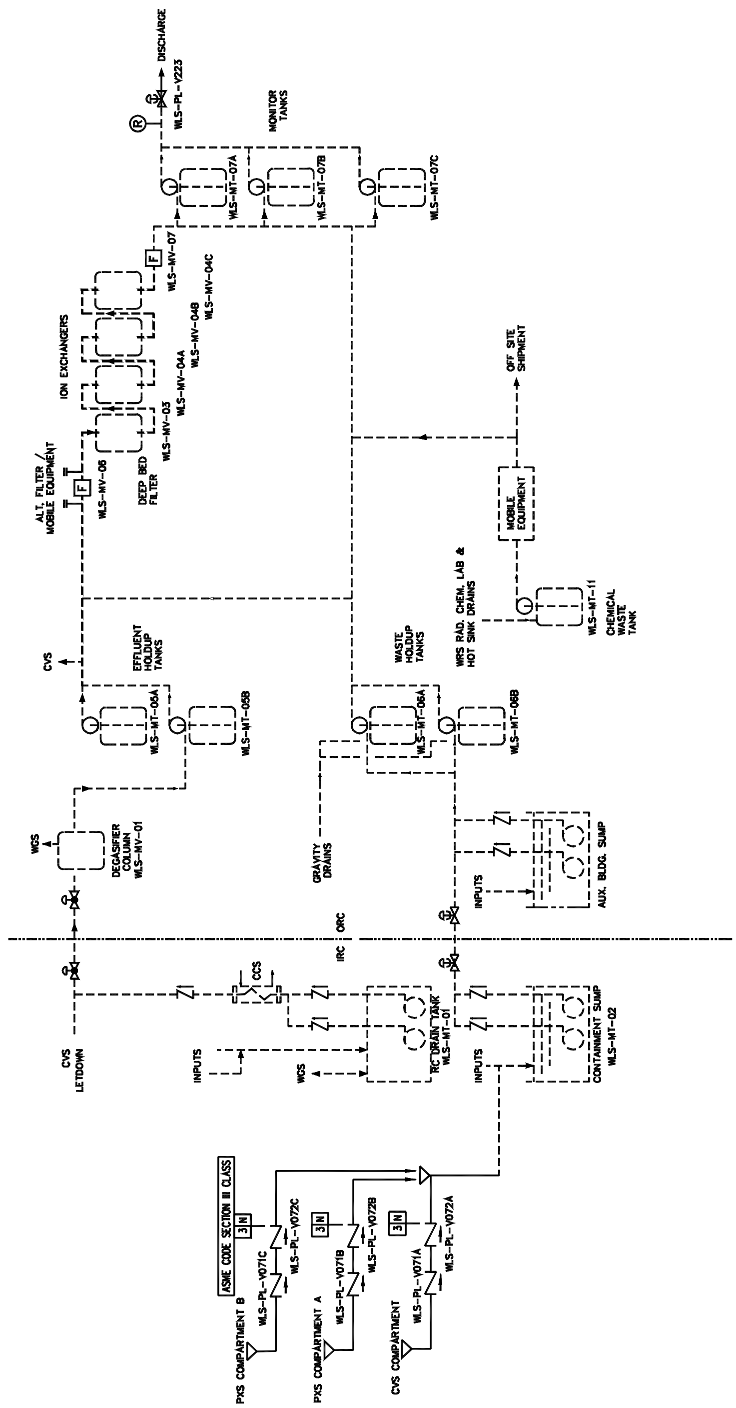


Figure 2.3.10-1
Liquid Radwaste System

2.3.11 Gaseous Radwaste System

Design Description

The gaseous radwaste system (WGS) receives, processes, and discharges the radioactive waste gases received within acceptable off-site release limits during normal modes of plant operation including power generation, shutdown and refueling.

The WGS is as shown in Figure 2.3.11-1 and the component locations of the WGS are as shown in Table 2.3.11-3.

1. The functional arrangement of the WGS is as described in the Design Description of this Section 2.3.11.

2. The seismic Category I equipment identified in Table 2.3.11-1 can withstand seismic design basis loads without loss of its structural integrity function.

3. The WGS provides the nonsafety-related functions of:

   c) Processing radioactive gases prior to discharge.

   d) Controlling the releases of radioactive materials in gaseous effluents.

   e) The WGS is purged with nitrogen on indication of high oxygen levels in the system.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.3.11-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the WGS.

Table 2.3.11-1		
Equipment Name	Tag No.	Seismic Category 1
WGS Activated Carbon Delay Bed A	WGS-MV-02A	Yes
WGS Activated Carbon Delay Bed B	WGS-MV-02B	Yes
WGS Discharge Isolation Valve	WGS-PL-V051	No

Table 2.3.11-2
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the WGS is as described in the Design Description of this Section 2.3.11.	Inspection of the as-built system will be performed.	The as-built WGS conforms with the functional arrangement as described in the Design Description of this Section 2.3.11.
2. The seismic Category I equipment identified in Table 2.3.11-1 can withstand seismic design basis loads without loss of its structural integrity function.	i) Inspection will be performed to verify that the seismic Category I equipment identified in Table 2.3.11-1 is located on the Nuclear Island.	i) The seismic Category I equipment identified in Table 2.3.11-1 is located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis loads without loss of its safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) A report exists and concludes that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.
3.a) The WGS provides the nonsafety-related function of processing radioactive gases prior to discharge.	Inspection will be performed to verify the contained volume of each of the activated carbon delay beds, WGS-MV02A and WGS-MV02B.	A report exists and concludes that the contained volume in each of the activated carbon delay beds, WGS-MV02A and WGS-MV02B, is at least 80 ft^3.
3.b) The WGS provides the nonsafety-related function of controlling the releases of radioactive materials in gaseous effluents.	Tests will be performed to confirm that the presence of a simulated high radiation signal from the discharge radiation monitor, WGS-017, causes the discharge control isolation valve WGS-PL-V051 to close.	A simulated high radiation signal causes the discharge control isolation valve WGS-PL-V051 to close.

Table 2.3.11-2 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3.c) The WGS is purged with nitrogen on indication of high oxygen levels in the system.	Tests will be performed to confirm that the presence of a simulated high oxygen level signal from the oxygen monitors (WGS-025A, -025B) causes the nitrogen purge valve (WGS-PL-V002) to open and the WLS degasifier vacuum pumps (WLS-MP-03A, -03B) to stop.	A simulated high oxygen level signal causes the nitrogen purge valve (WGS-PL-V002) to open and the WLS degasifier vacuum pumps (WLS-MP-03A, -03B) to stop.

Table 2.3.11-3		
Equipment Name	**Tag No.**	**Component Location**
WGS Gas Cooler	WGS-ME-01	Auxiliary Building
WGS Moisture Separator	WGS-MV-03	Auxiliary Building
WGS Activated Carbon Delay Bed A	WGS-MV-02A	Auxiliary Building
WGS Activated Carbon Delay Bed B	WGS-MV-02B	Auxiliary Building

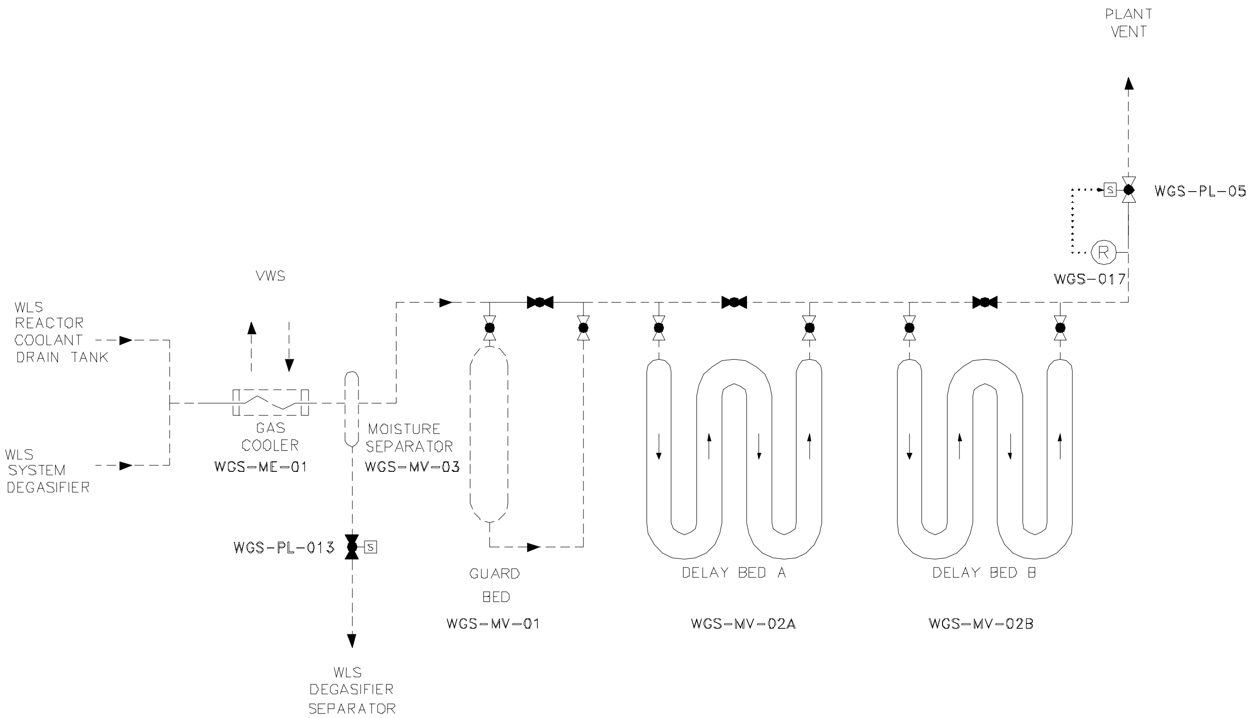


Figure 2.3.11-1
Gaseous Radwaste System

2.3.12 Solid Radwaste System

Design Description

The solid radwaste system (WSS) receives, collects, and stores the solid radioactive wastes received prior to their processing and packaging by mobile equipment for shipment off-site.

The component locations of the WSS are as shown in Table 2.3.12-2.

1. The functional arrangement of the WSS is as described in the Design Description of this Section 2.3.12.

2. The WSS provides the nonsafety-related function of storing radioactive spent resins prior to processing or shipment.

Table 2.3.12-1 Inspections, Tests, Analyses, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The functional arrangement of the WSS is as described in the Design Description of this Section 2.3.12.	Inspection of the as-built system will be performed.	The as-built WSS conforms with the functional arrangement as described in the Design Description of this Section 2.3.12.
2. The WSS provides the nonsafety-related function of storing radioactive solids prior to processing or shipment.	Inspection will be performed to verify that the volume of each of the spent resin tanks, WSS-MV01A and WSS-MV01B, is at least 250 ft^3.	A report exists and concludes that the volume of each of the spent resin tanks, WSS-MV01A and WSS-MV01B, is at least 250 ft^3.

Table 2.3.12-2		
Component Name	**Tag No.**	**Component Location**
WSS Spent Resin Tank A	WSS-MV-01A	Auxiliary Building
WSS Spent Resin Tank B	WSS-MV-01B	Auxiliary Building

2.3.13 Primary Sampling System

The primary sampling system collects samples of fluids in the reactor coolant system (RCS) and the containment atmosphere during normal operations.

The PSS is as shown in Figure 2.3.13-1. The PSS Grab Sampling Unit (PSS-MS-01) is located in the Auxiliary Building.

1. The functional arrangement of the PSS is as described in the Design Description of this Section 2.3.13.

2. The components identified in Table 2.3.13-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.

3. Pressure boundary welds in components identified in Table 2.3-13-1 as ASME Code Section III meet ASME Code Section III requirements.

4. The components identified in Table 2.3.13-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.

5. The seismic Category I equipment identified in Table 2.3.13-1 can withstand seismic design basis loads without loss of safety function.

6. a) The Class 1E equipment identified in Table 2.3.13-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of their safety function, for the time required to perform the safety function.

   b) The Class 1E components identified in Table 2.3.13-1 are powered from their respective Class 1E division.

   c) Separation is provided between PSS Class 1E divisions, and between Class 1E divisions and non-Class 1E divisions.

7. The PSS provides the safety-related function of preserving containment integrity by isolation of the PSS lines penetrating the containment.

8. The PSS provides the nonsafety-related function of providing the capability of obtaining reactor coolant and containment atmosphere samples.

9. Safety-related displays identified in Table 2.3.13-1 can be retrieved in the MCR.

10. a) Controls exist in the MCR to cause those remotely operated valves identified in Table 2.3.13-1 to perform active functions.

    b) The valves identified in Table 2.3.13-1 as having protection and safety monitoring system (PMS) control perform an active function after receiving a signal from the PMS.

11. a) The check valve identified in Table 2.3.13-1 perform an active safety-related function to change position as indicated in the table.

    b) After loss of motive power, the remotely operated valves identified in Table 2.3.13-1 assume the indicated loss of motive power position.

12. Controls exist in the MCR to cause the valves identified in Table 2.3.13-2 to perform the listed function.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.3.13-3 specifies the inspections, tests, analyses, and associated acceptance criteria for the PSS.

Table 2.3.13-1									
Equipment Name	**Tag No.**	**ASME Code Section III**	**Seismic Cat. I**	**Remotely Operated Valve**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**	**Control PMS/DAS**	**Active Function**	**Loss of Motive Power Position**
Liquid Sample Line Containment Isolation Valve Outside Reactor Containment (ORC)	PSS-PL-V011	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Closed	Closed
Liquid Sample Line Containment Isolation Valve Inside Reactor Containment (IRC)	PSS-PL-V010A	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/No	Transfer Closed	Closed
Liquid Sample Line Containment Isolation Valve IRC	PSS-PL-V010B	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/No	Transfer Closed	Closed
Containment Air Sample Containment Isolation Valve IRC	PSS-PL-V008	Yes	Yes	Yes	Yes/Yes	Yes (Valve Position)	Yes/No	Transfer Closed	Closed
Air Sample Line Containment Isolation Valve ORC	PSS-PL-V046	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Closed	Closed
Sample Return Line Containment Isolation Valve ORC	PSS-PL-V023	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Closed	Closed
Sample Return Containment Isolation Check Valve IRC	PSS-PL-V024	Yes	Yes	No	-/-	No	-/-	Transfer Closed	Closed

Note: A dash (-) indicates not applicable.

Table 2.3.13-2		
Equipment Name	**Tag No.**	**Control Function**
Reactor Coolant System (RCS) Sample Isolation Valve A	PSS-PL-V001A	Transfer Open/Transfer Closed
RCS Sample Isolation Valve B	PSS-PL-V001B	Transfer Open/Transfer Closed

Table 2.3.13-3
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the PSS is as described in the Design Description of this Section 2.3.13.	Inspection of the as-built system will be performed.	The as-built PSS conforms with the functional arrangement as described in the Design Description of this Section 2.3.13.
2. The components identified in Table 2.3.13-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built components as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built components identified in Table 2.3.13-1 as ASME Code Section III.
3. Pressure boundary welds in components identified in Table 2.3.13-1 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for non-destructive examination of pressure boundary welds.
4. The components identified in Table 2.3.13-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.	A hydrostatic test will be performed on the components required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the hydrostatic test of the components identified in Table 2.3.13-1 as ASME Code Section III conform with the requirements of the ASME Code Section III.
5. The seismic Category I equipment identified in Table 2.3.13-1 can withstand seismic design basis loads without loss of its safety function.	i) Inspection will be performed to verify that the seismic Category I equipment and valves identified in Table 2.3.13-1 are located on the Nuclear Island.	i) The seismic Category I equipment identified in Table 2.3.13-1 is located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis loads without loss of safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) A report exists and concludes that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.

Table 2.3.13-3 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6.a) The Class 1E equipment identified in Tables 2.3.13-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of their safety function, for the time required to perform the safety function.	i) Type tests, analyses, or a combination of type tests and analyses will be performed on Class 1E equipment located in a harsh environment.	i) A report exists and concludes that the Class 1E equipment identified in Table 2.3.13-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of its safety function for the time required to perform the safety function.
	ii) Inspection will be performed of the as-installed Class 1E equipment and the associated wiring, cables, and terminations located in a harsh environment.	ii) A report exists and concludes that the as-installed Class 1E equipment and the associated wiring, cables, and terminations identified in Table 2.3.13-1 as being qualified for a harsh environment are bounded by type tests, analyses, or a combination of type tests and analyses.
6.b) The Class 1E components identified in Table 2.3.13-1 are powered from their respective Class 1E division.	Testing will be performed on the PSS by providing a simulated test signal in each Class 1E division.	A simulated test signal exists at the Class 1E equipment identified in Table 2.3.13-1 when the assigned Class 1E division is provided the test signal.
6.c) Separation is provided between PSS Class 1E divisions, and between Class 1E divisions and non-Class 1E divisions.	See Tier 1 Material, Table 3.3-6, item 7.d.	See Tier 1 Material, Table 3.3-6, item 7.d.
7. The PSS provides the safety-related function of preserving containment integrity by isolation of the PSS lines penetrating the containment.	See Tier 1 Material, Table 2.2.1-3, item 7.	See Tier 1 Material, Table 2.2.1-3, item 7.
8. The PSS provides the nonsafety-related function of providing the capability of obtaining reactor coolant and containment atmosphere samples.	Testing will be performed to obtain samples of the reactor coolant and containment atmosphere.	A sample is drawn from the reactor coolant and the containment atmosphere.
9. Safety-related displays identified in Table 2.3.13-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the safety-related displays in the MCR.	The safety-related displays identified in Table 2.3.13-1 can be retrieved in the MCR.

Table 2.3.13-3 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
10.a) Controls exist in the MCR to cause those remotely operated valves identified in Table 2.3.13-1 to perform active functions.	Stroke testing will be performed on the remotely operated valves identified in Table 2.3.13-1 using the controls in the MCR.	Controls in the MCR operate to cause those remotely operated valves identified in Table 2.3.13-1 to perform active functions.
10.b) The valves identified in Table 2.3.13-1 as having PMS control perform an active function after receiving a signal from the PMS.	Testing will be performed on remotely operated valves listed in Table 2.3.13-1 using real or simulated signals into the PMS.	The remotely operated valves identified in Table 2.3.13-1 as having PMS control perform the active function identified in the table after receiving a signal from the PMS.
11.a) The check valve identified in Table 2.3.13-1 performs an active safety-related function to change position as indicated in the table.	Exercise testing of the check valve with an active safety function identified in Table 2.3.13-1 will be performed under preoperational test pressure, temperature, and fluid flow conditions.	The check valve changes position as indicated in Table 2.3.13-1.
11.b) After loss of motive power, the remotely operated valves identified in Table 2.3.13-1 assume the indicated loss of motive power position.	Testing of the installed valves will be performed under the conditions of loss of motive power.	After loss of motive power, each remotely operated valve identified in Table 2.3.13-1 assumes the indicated loss of motive power position.
12. Controls exist in the MCR to cause the valves identified in Table 2.3.13-2 to perform the listed function.	Testing will be performed on the components in Table 2.3.13-2 using controls in the MCR.	Controls in the MCR cause valves identified in Table 2.3.13-2 to perform the listed functions.

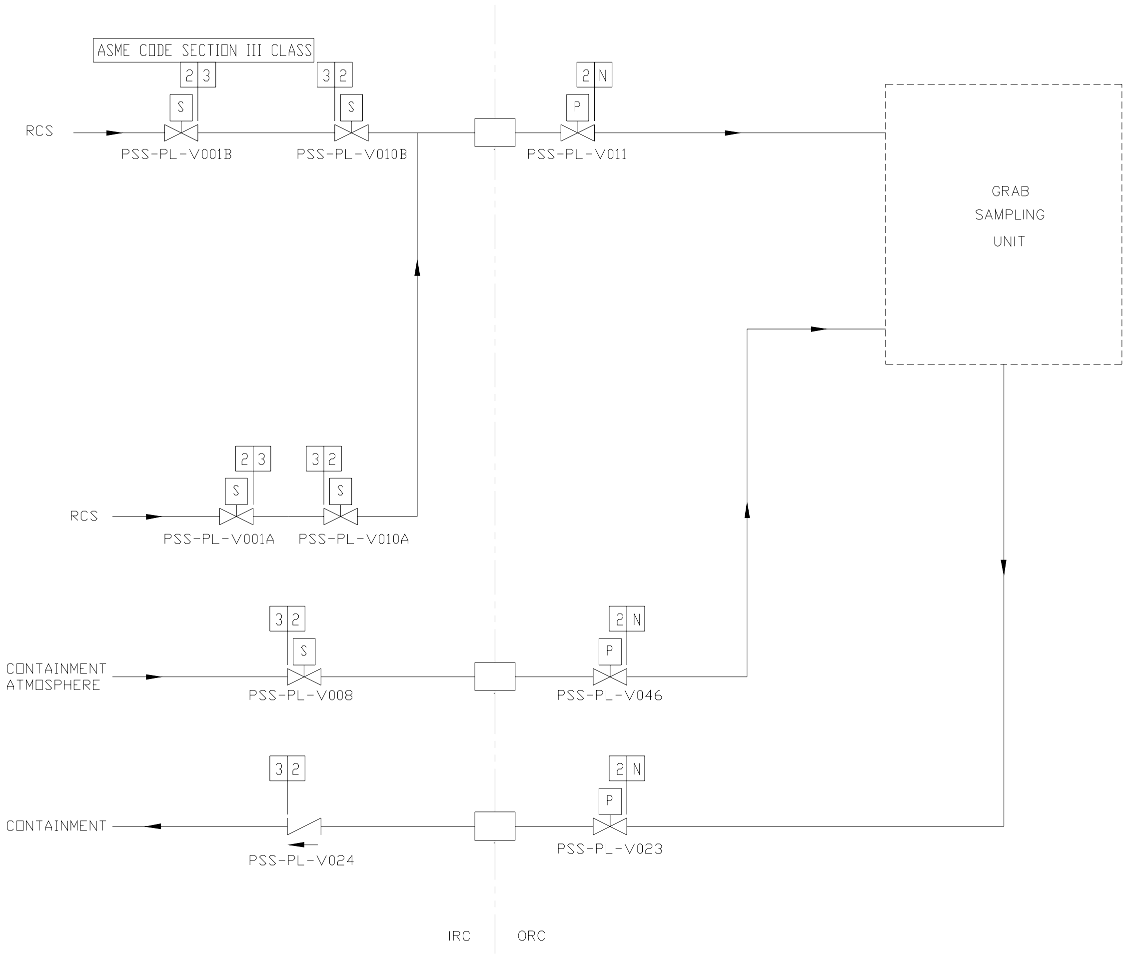


Figure 2.3.13-1
Primary Sampling System

2.3.14 Demineralized Water Transfer and Storage System

Design Description

The demineralized water transfer and storage system (DWS) receives water from the demineralized water treatment system (DTS), and provides a reservoir of demineralized water to supply the condensate storage tank and for distribution throughout the plant. Demineralized water is processed in the DWS to remove dissolved oxygen. In addition to supplying water for makeup of systems which require pure water, the demineralized water is used to sluice spent radioactive resins from the ion exchange vessels in the chemical and volume control system (CVS), the spent fuel pool cooling system (SFS), and the liquid radwaste system (WLS) to the solid radwaste system (WSS).

The component locations of the DWS are as shown in Table 2.3.14-3.

1. The functional arrangement of the DWS is as described in the Design Description of this Section 2.3.14.

2. The DWS provides the safety-related function of preserving containment integrity by isolation of the DWS lines penetrating the containment.

3. The DWS condensate storage tank (CST) provides the nonsafety-related function of water supply to the FWS startup feedwater pumps.

4. Displays of the parameters identified in Table 2.3.14-1 can be retrieved in the main control room (MCR).

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.3.14-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the DWS.

Table 2.3.14-1			
Equipment Name	**Tag No.**	**Display**	**Control Function**
Condensate Storage Tank Water Level	DWS-006	Yes	-

Note: Dash (-) indicates not applicable.

Table 2.3.14-2
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the DWS is as described in the Design Description of this Section 2.3.14.	Inspection of the as-built system will be performed.	The as-built DWS conforms with the functional arrangement as described in the Design Description of this Section 2.3.14.
2. The DWS provides the safety-related function of preserving containment integrity by isolation of the DWS lines penetrating the containment.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.
3. The DWS CST provides the nonsafety-related function of water supply to the FWS startup feedwater tanks.	Inspection of the DWS CST will be performed.	The volume of the CST between the tank overflow and the startup feedwater pumps supply connection is greater than or equal to 325,000 gallons.
4. Displays of the parameters identified in Table 2.3.14-1 can be retrieved in the MCR.	Inspection will be performed for retrievability or parameters in the MCR.	The displays identified in Table 2.3.14-1 can be retrieved in the MCR.

Table 2.3.14-3		
Component Name	**Tag No.**	**Component Location**
Demineralizer Water Storage Tank Degasification System Package	DWS-MS-01	Annex Building
Condensate Storage Tank Degasification System Package	DWS-MS-02	Turbine Building
Demineralized Water Storage Tank	DWS-MT-01	Yard
Condensate Storage Tank	DWS-MT-02	Yard

2.3.15 Compressed and Instrument Air System

Design Description

The compressed and instrument air system (CAS) consists of three subsystems; instrument air, service air, and high-pressure air. The instrument air subsystem supplies compressed air for air-operated valves and dampers. The service air subsystem supplies compressed air at outlets throughout the plant to power air-operated tools and is used as a motive force for air-powered pumps. The service air subsystem is also utilized as a supply source for breathing air. The high-pressure air subsystem supplies air to the main control room emergency habitability system (VES), the generator breaker package, and fire fighting apparatus recharge station.

The CAS is required for normal operation and startup of the plant.

The component locations of the CAS are as shown in Table 2.3.15-3.

1. The functional arrangement of the CAS is as described in the Design Description of this Section 2.3.15.

2. The CAS provides the safety-related function of preserving containment integrity by isolation of the CAS lines penetrating the containment.

3. Displays of the parameters identified in Table 2.3.15-1 can be retrieved in the main control room (MCR).

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.3.15-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the CAS.

Table 2.3.15-1

Equipment Name	Tag No.	Display	Control Function
Instrument Air Pressure	CAS-011	Yes	-

Note: Dash (-) indicates not applicable.

Table 2.3.15-2 Inspections, Tests, Analyses, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The functional arrangement of the CAS is as described in the Design Description of this Section 2.3.15.	Inspection of the as-built system will be performed.	The as-built CAS conforms with the functional arrangement as described in the Design Description of this Section 2.3.15.
2. The CAS provides the safety-related function of preserving containment integrity by isolation of the CAS lines penetrating the containment.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.
3. Displays of the parameters identified in Table 2.3.15-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of parameters in the MCR.	The displays identified in Table 2.3.15-1 can be retrieved in the MCR.

Table 2.3.15-3		
Component Name	**Tag No.**	**Component Location**
Instrument Air Compressor Package A	CAS-MS-01A	Turbine Building
Instrument Air Compressor Package B	CAS-MS-01B	Turbine Building
Instrument Air Dryer Package A	CAS-MS-02A	Turbine Building
Instrument Air Dryer Package B	CAS-MS-02B	Turbine Building
Service Air Compressor Package A	CAS-MS-03A	Turbine Building
Service Air Compressor Package B	CAS-MS-03B	Turbine Building
Service Air Dryer Package A	CAS-MS-04A	Turbine Building
Service Air Dryer Package B	CAS-MS-04B	Turbine Building
High Pressure Air Compressor and Filter Package	CAS-MS-05	Turbine Building
Instrument Air Receiver A	CAS-MT-01A	Turbine Building
Instrument Air Receiver B	CAS-MT-01B	Turbine Building
Service Air Receiver	CAS-MT-02	Turbine Building

2.3.16 Potable Water System

No entry for this system.

2.3.17 Waste Water System

No entry for this system.

2.3.18 Plant Gas System

No entry. Covered in Section 3.3, Buildings.

2.3.19 Communication System

Design Description

The communication system (EFS) provides intraplant communications during normal, maintenance, transient, fire, and accident conditions, including loss of offsite power.

1. a) The EFS has handsets, amplifiers, loudspeakers, and siren tone generators connected as a telephone/page system.

   f) The EFS has sound-powered equipment connected as a system.

2. The EFS provides the following nonsafety-related functions:

   g) The EFS telephone/page system provides intraplant, station-to-station communications and area broadcasting between the main control room (MCR) and the locations listed in Table 2.3.19-1.

   h) The EFS provides sound-powered communications between the MCR, the remote shutdown workstation (RSW), the Division A, B, C, D dc equipment rooms (Rooms 12201/12203/12205/12207), the Division A, B, C, D I&C rooms (Rooms 12301/12302/12304/12305), and the diesel generator building (Rooms 60310/60320) without external power.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.3.19-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the EFS.

Table 2.3.19-1	
Telephone/Page System Equipment	**Location**
Fuel Handling Area	12562
Division A, B, C, D dc Equipment Rooms	12201/12203/12205/12207
Division A, B, C, D I&C Rooms	12301/12302/12304/12305
Maintenance Floor Staging Area	12351
Containment Maintenance Floor	11300
Containment Operating Deck	11500

Table 2.3.19-2
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1.a) The EFS has handsets, amplifiers, loudspeakers, and siren tone generators connected as a telephone/page system.	Inspection of the as-built system will be performed.	The as-built EFS has handsets, amplifiers, loudspeakers, and siren tone generators connected as a telephone/page system.
1.b) The EFS has sound-powered equipment connected as a system.	Inspection of the as-built system will be performed.	The as-built EFS has sound-powered equipment connected as a system.
2.a) The EFS telephone/page system provides intraplant, station-to-station communications and area broadcasting between the MCR and the locations listed in Table 2.3.19-1.	An inspection and test will be performed on the telephone/page communication equipment.	Telephone/page equipment is installed and voice transmission and reception from the MCR are accomplished.
2.b) EFS provides sound-powered communications between the MCR, the RSW, the Division A, B, C, D dc equipment rooms (Rooms 12201/12203/12205/12207), the Division A, B, C, D I&C rooms (Rooms 12301/12302/12304/12305), and the diesel generator building (Rooms 60310/60320) without external power.	An inspection and test will be performed of the sound-powered communication equipment.	Sound-powered equipment is installed and voice transmission and reception are accomplished.

2.3.20 Turbine Building Closed Cooling Water System

No entry for this system.

2.3.21 Secondary Sampling System

No entry for this system.

2.3.22 Containment Leak Rate Test System

No entry. Covered in Section 2.2.1, Containment System.

2.3.23 This section intentionally blank

2.3.24 Demineralized Water Treatment System

No entry for this system.

2.3.25 Gravity and Roof Drain Collection System

No entry for this system.

2.3.26 This section intentionally blank

2.3.27 Sanitary Drainage System

No entry for this system.

2.3.28 Turbine Island Vents, Drains, and Relief System

No entry for this system.

2.3.29 Radioactive Waste Drain System

Design Description

The radioactive waste drain system (WRS) collects radioactive and potentially radioactive liquid wastes from equipment and floor drains during normal operation, startup, shutdown, and refueling. The liquid wastes are then transferred to appropriate processing and disposal systems.

Nonradioactive wastes are collected by the waste water system (WWS). The WRS is as shown in Figure 2.3.29-1.

1. The functional arrangement of the WRS is as described in the Design Description of this Section 2.3.29.

2. The WRS collects liquid wastes from the equipment and floor drainage of the radioactive portions of the auxiliary building, annex building, and radwaste building and directs these wastes to a WRS sump or WLS waste holdup tanks located in the auxiliary building.

3. The WRS collects chemical wastes from the auxiliary building chemical laboratory drains and the decontamination solution drains in the annex building and directs these wastes to the chemical waste tank of the liquid radwaste system.

4. The WWS stops the discharge of waste water to the circulating water system upon detection of high radiation in the waste retention basin discharge stream to the circulating water system.

Table 2.3.29-1
Inspection, Tests, Analyses and Acceptance Criteria

Design Commitment	Inspection, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the WRS is as described in the Design Description of this Section 2.3.29.	Inspection of the as-built system will be performed.	The as-build WRS conforms with the functional arrangement as described in the Design Description of this Section 2.3.29.
2. The WRS collects liquid wastes from the equipment and floor drainage of the radioactive portions of the auxiliary building, annex building, and radwaste building and directs these wastes to a WRS sump or WLS waste holdup tanks located in the auxiliary building.	A test is performed by pouring water into the equipment and floor drains in the radioactive portions of the auxiliary building, annex building, and radwaste building.	The water poured into these drains is collected either in the auxiliary building radioactive drains sump or the WLS waste holdup tanks.
3. The WRS collects chemical wastes from the auxiliary building chemical laboratory drains and the decontamination solution drains in the annex building and directs these wastes to the chemical waste tank of the liquid radwaste system.	A test is performed by pouring water into the auxiliary building chemical laboratory and the decontamination solution drains in the annex building.	The water poured into these drains is collected in the chemical waste tank of the liquid radwaste system.
4. The WWS stops the discharge of waste water to the circulating water system upon detection of high radiation in the waste retention basin discharge stream to the circulating water system.	Tests will be performed to confirm that a simulated high radiation signal from the waste water retention basin discharge radiation monitor, WWS-021 causes the basin transfer pumps (WWS-MP-04A and B) to stop running.	A simulated high radiation signal causes the basin transfer pumps (WWS-MP-04A and B) to stop running.

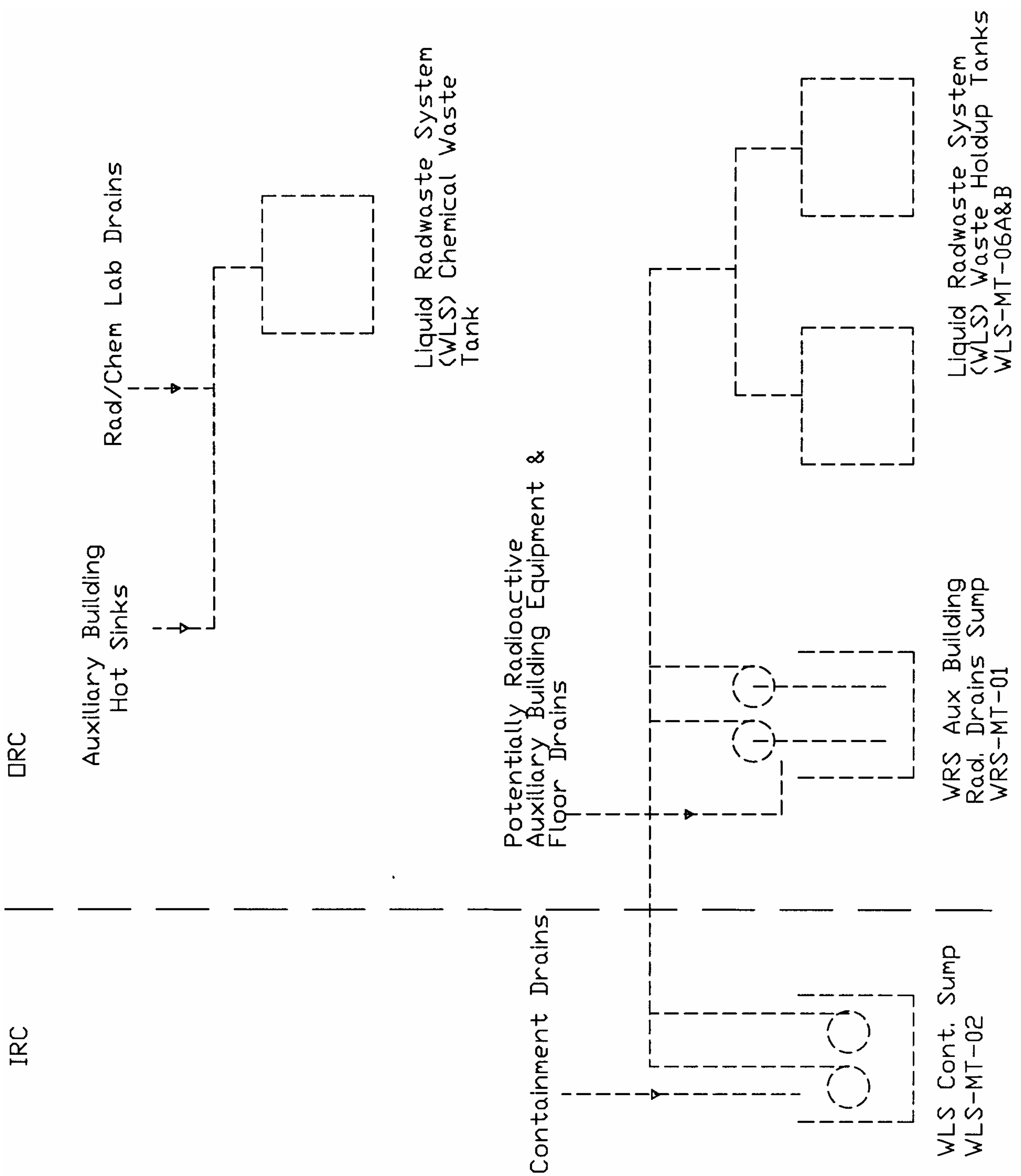


Figure 2.3.29-1
Radioactive Waste Drain System

2.4.1 Main and Startup Feedwater System

See Section 2.2.4 for information on the main feedwater system.

Design Description

The startup feedwater system supplies feedwater to the steam generators during plant startup, hot standby and shutdown conditions, and during transients in the event of main feedwater system unavailability.

1. The functional arrangement of the startup feedwater system is as described in the Design Description of this Section 2.4.1.

2. The FWS provides the following nonsafety-related functions:

   The FWS provides startup feedwater flow from the condensate storage tank (CST) to the steam generator system (SGS) for heat removal from the RCS.

3. Controls exist in the main control room (MCR) to cause the components identified in Table 2.4.1-1 to perform the listed function.

4. Displays of the parameters identified in Table 2.4.1-1 can be retrieved in the MCR.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.4.1-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the FWS.

Table 2.4.1-1			
Equipment Name	**Tag No.**	**Display**	**Control Function**
Startup Feedwater Pump A (Motor)	FWS-MP-03A	Yes (Run Status)	Start
Startup Feedwater Pump B (Motor)	FWS-MP-03B	Yes (Run Status)	Start
Startup Feedwater Pump A Isolation Valve	FWS-PL-V013A	Yes (Valve Position)	Open
Startup Feedwater Pump B Isolation Valve	FWS-PL-V013B	Yes (Valve Position)	Open

Table 2.4.1-2
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the startup feedwater system is as described in the Design Description of this Section 2.4.1.	Inspection of the as-built system will be performed.	The as-built startup feedwater system conforms with the functional arrangement as described in the Design Description of this Section 2.4.1.
2. The FWS provides startup feedwater flow from the CST to the SGS for heat removal from the RCS.	Testing will be performed to confirm that each of the startup feedwater pumps can provide water from the CST to both steam generators.	Each FWS startup feedwater pump provides a flow rate greater than or equal to 260 gpm to each steam generator system at a steam generator secondary side pressure of at least 1106 psia.
3. Controls exist in the MCR to cause the components identified in Table 2.4.1-1 to perform the listed function.	Testing will be performed on the components in Table 2.4.1-1 using controls in the MCR.	Controls in the MCR operate to cause the components listed in Table 2.4.1-1 to perform the listed functions.
4. Displays of the parameters identified in Table 2.4.1-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of parameters in the MCR.	The displays identified in Table 2.4.1-1 can be retrieved in the MCR.

Table 2.4.1-3

Component Name	Tag No.	Component Location
Startup Feedwater Pump A	FWS-MP-03A	Turbine Building
Startup Feedwater Pump B	FWS-MP-03B	Turbine Building

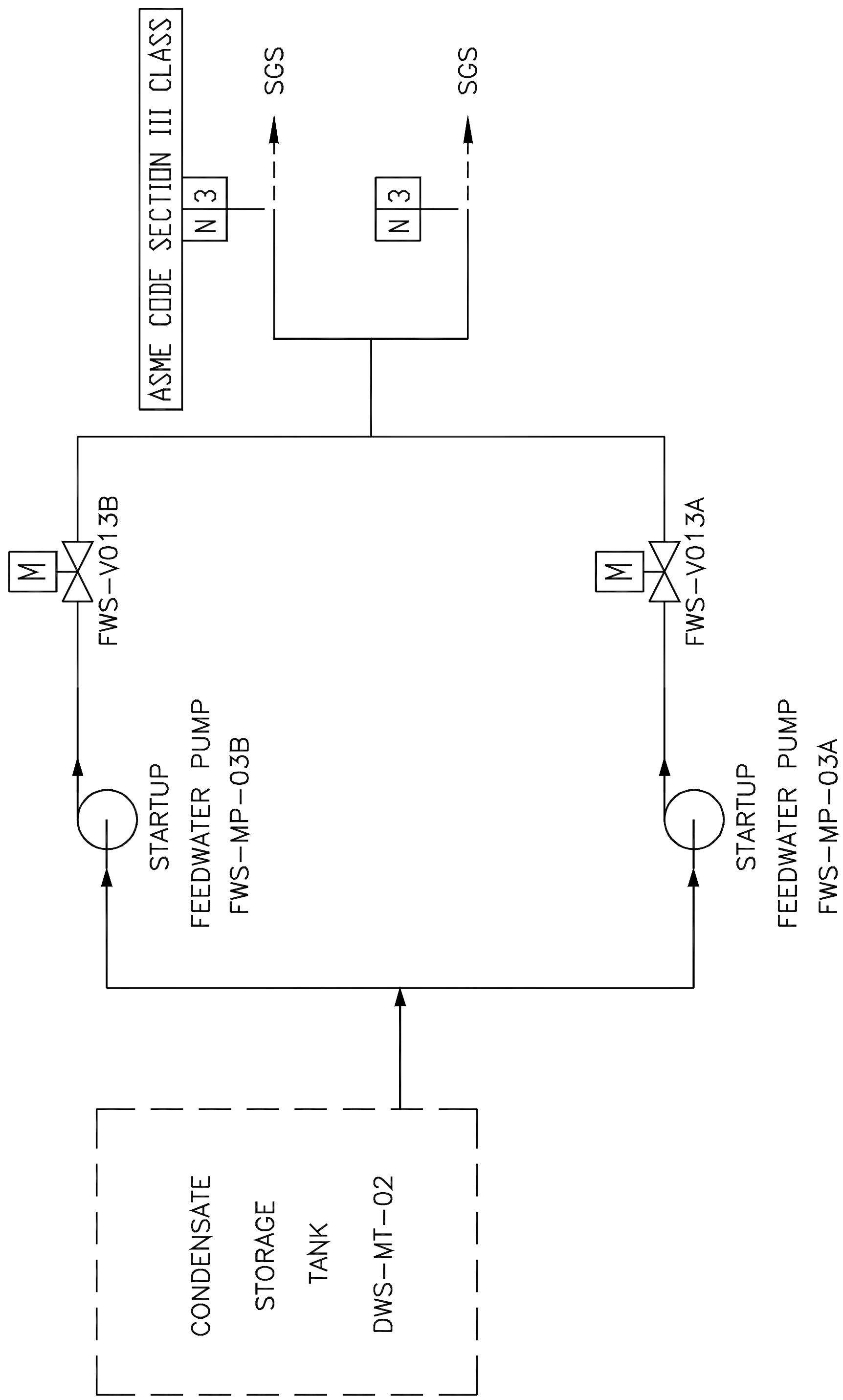


Figure 2.4.1-1
Main and Startup Feedwater System

2.4.2 Main Turbine System

Design Description

The main turbine system (MTS) is designed for electric power production consistent with the capability of the reactor and the reactor coolant system.

The component locations of the MTS are as shown in Table 2.4.2-2.

1. The functional arrangement of the MTS is as described in the Design Description of this Section 2.4.2.

2. a) Controls exist in the MCR to trip the main turbine-generator.

   b) The main turbine-generator trips after receiving a signal from the PMS.

   c) The main turbine-generator trips after receiving a signal from the DAS.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.4.2-1 specifies the inspections, tests, analyses, and associated acceptance criteria for the MTS.

Table 2.4.2-1
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Test, Analyses	Acceptance Criteria
1. The functional arrangement of the MTS is as described in the Design Description of this Section 2.4.2.	Inspection of the as-built system will be performed.	The as-built MTS conforms with the functional arrangement as described in the Design Description of this Section 2.4.2.
2.a) Controls exist in the MCR to trip the main turbine-generator.	Testing will be performed on the main turbine-generator using controls in the MCR.	Controls in the MCR operate to trip the main turbine-generator.
2.b) The main turbine-generator trips after receiving a signal from the PMS.	Testing will be performed using real or simulated signals into the PMS.	The main turbine-generator trips after receiving a signal from the PMS.
2.c) The main turbine-generator trips after receiving a signal from the DAS.	Testing will be performed using real or simulated signals into the DAS.	The main turbine-generator trips after receiving a signal from the DAS.

Table 2.4.2-2		
Component Name	**Tag No.**	**Component Location**
HP Turbine	MTS-MG-01	Turbine Building
LP Turbine A	MTS-MG-02A	Turbine Building
LP Turbine B	MTS-MG-02B	Turbine Building
LP Turbine C	MTS-MG-02C	Turbine Building
Gland Steam Condenser	GSS-ME-01	Turbine Building
Gland Condenser Vapor Exhauster 1A	GSS-MA-01A	Turbine Building
Gland Condenser Vapor Exhauster 1B	GSS-MA-01B	Turbine Building
Mechanical Overspeed Trip Device	--	Turbine Building
Electrical Overspeed Trip Device	--	Turbine Building

2.4.3 Main Steam System

No entry. Covered in Section 2.2.4, Steam Generator System.

2.4.4 Steam Generator Blowdown System

No entry. Containment isolation function covered in Section 2.2.1, Containment System and 2.2.4, Steam Generator System.

No entry. Steam generator isolation function covered in Section 2.2.4, Steam Generator System.

2.4.5 Condenser Air Removal System

No entry. Covered in Section 3.5, Radiation Monitoring.
(Note: Monitor is TDS-RE001.)

2.4.6 Condensate System

Design Description

The condensate system (CDS) provides feedwater at the required temperature, pressure, and flow rate to the deaerator. Condensate is pumped from the main condenser hotwell by the condensate pumps and passes through the low-pressure feedwater heaters to the deaerator. The circulating water system (CWS) removes heat from the condenser and is site specific starting from the interface at the locations where the CWS piping enters and exits the turbine building.

The CDS operates during plant startup and power operations (full and part loads).

The component locations of the CDS are as shown in Table 2.4.6-3.

1. The functional arrangement of the CDS is as described in the Design Description of this Section 2.4.6.

2. Displays of the parameters identified in Table 2.4.6-1 can be retrieved in the main control room (MCR).

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.4.6-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the CDS.

Table 2.4.6-1

Equipment Name	Tag No.	Display
Condenser Backpressure	CDS-056A	Yes
Condenser Backpressure	CDS-056B	Yes
Condenser Backpressure	CDS-056C	Yes

Table 2.4.6-2
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the CDS is as described in the Design Description of this Section 2.4.6.	Inspection of the as-built system will be performed.	The as-built CDS conforms with the functional arrangement as described in the Design Description of Section 2.4.6.
2. Displays of the parameters identified in Table 2.4.6-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the parameters in the MCR.	The displays identified in Table 2.4.6-1 can be retrieved in the MCR.

Table 2.4.6-3	
Component Name	**Component Location**
Low Pressure Feedwater Heaters	Turbine Building
Deaerator Feedwater Heater and Storage Tank	Turbine Building
Main Condenser Shell A	Turbine Building
Main Condenser Shell B	Turbine Building
Main Condenser Shell C	Turbine Building
Condensate Pump A	Turbine Building
Condensate Pump B	Turbine Building
Condensate Pump C	Turbine Building

2.4.7 Circulating Water System

No entry for this system.

2.4.8 Auxiliary Steam Supply System

No entry for this system.

2.4.9 Condenser Tube Cleaning System

No entry for this system.

2.4.10 Turbine Island Chemical Feed System

No entry for this system.

2.4.11 Condensate Polishing System

No entry for this system.

2.4.12 Gland Seal System

No entry. Covered in Section 2.4.2, Main Turbine System.

2.4.13 Generator Hydrogen and CO_2 System

No entry for this system.

2.4.14 Heater Drain System

No entry for this system.

2.4.15 Hydrogen Seal Oil System

No entry for this system.

2.4.16 Main Turbine and Generator Lube Oil System

No entry for this system.

2.5.1 Diverse Actuation System

Design Description

The diverse actuation system (DAS) initiates reactor trip, actuates selected functions, and provides plant information to the operator.

The component locations of the DAS are as shown in Table 2.5.1-5.

1. The functional arrangement of the DAS is as described in the Design Description of this Section 2.5.1.

2. The DAS provides the following nonsafety-related functions:

   a) The DAS provides an automatic reactor trip on low wide-range steam generator water level or on low pressurizer water level separate from the PMS.

   b) The DAS provides automatic actuation of selected functions, as identified in Table 2.5.1-1, separate from the PMS.

   c) The DAS provides manual initiation of reactor trip and selected functions, as identified in Table 2.5.1-2, separate from the PMS. These manual initiation functions are implemented in a manner that bypasses the control room multiplexers, the PMS cabinets, and the signal processing equipment of the DAS.

   d) The DAS provides main control room (MCR) displays of selected plant parameters, as identified in Table 2.5.1-3, separate from the PMS.

3. The DAS has the following features:

   a) The signal processing hardware of the DAS uses input modules, output modules, and microprocessor boards that are different than those used in the PMS.

   b) The display hardware of the DAS uses a different display device than that used in the PMS.

   c) Software used in the DAS uses an operating system and a programming language that are different than those used in the PMS.

   d) The DAS has electrical surge withstand capability (SWC), and can withstand the electromagnetic interference (EMI), radio frequency (RFI), and electrostatic discharge (ESD) conditions that exist where the DAS equipment is located in the plant.

   e) The sensors identified on Table 2.5.1-3 are used for DAS input and are separate from those being used by the PMS and plant control system.

   f) The DAS is powered by non-Class 1E uninterruptible power supplies that are independent and separate from the power supplies which power the PMS.

g) The DAS signal processing cabinets are provided with the capability for channel testing without actuating the controlled components.

h) The DAS equipment can withstand the room ambient temperature and humidity conditions that will exist at the plant locations in which the DAS equipment is installed at the times for which the DAS is designed to be operational.

4. The DAS hardware and software is developed using a planned design process which provides for specific design documentation and reviews during the following life cycle stages:

   a) Design requirements phase
   b) System definition phase
   c) Hardware and software development phase
   d) System test phase
   e) Installation phase

   The planned design process also provides for the use of commercial off-the-shelf hardware and software.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.5.1-4 specifies the inspections, tests, analyses, and associated acceptance criteria for the DAS.

Table 2.5.1-1
Functions Automatically Actuated by the DAS

1. Reactor and Turbine Trip on Low Wide-range Steam Generator Water Level or Low Pressurizer Water Level
2. Passive Residual Heat Removal (PRHR) Actuation and In-containment Refueling Water Storage Tank (IRWST) Gutter Isolation on Low Wide-range Steam Generator Water Level or on High Hot Leg Temperature
3. Core Makeup Tank (CMT) Actuation and Trip All Reactor Coolant Pumps on Low Wide-Range Steam Generator Water Level or Low Pressurizer Water Level
4. Isolation of Selected Containment Penetrations and Initiation of Passive Containment Cooling System (PCS) on High Containment Temperature

Table 2.5.1-2
Functions Manually Actuated by the DAS

1. Reactor and Turbine Trip
2. PRHR Actuation and IRWST Gutter Isolation
3. CMT Actuation and Trip All Reactor Coolant Pumps
4. First-stage Automatic Depressurization System (ADS) Valve Actuation
5. Second-stage ADS Valve Actuation
6. Third-stage ADS Valve Actuation
7. Fourth-stage ADS Valve Actuation
8. PCS Actuation
9. Isolation of Selected Containment Penetrations
10. Containment Hydrogen Ignitor Actuation
11. IRWST Injection Actuation
12. Containment Recirculation Actuation
13. Actuate IRWST Drain to Containment

Table 2.5.1-3
DAS Sensors and Displays

Equipment Name	Tag Number
Reactor Coolant System (RCS) Hot Leg Temperature	RCS-300A
RCS Hot Leg Temperature	RCS-300B
Steam Generator 1 Wide-range Level	SGS-044
Steam Generator 1 Wide-range Level	SGS-045
Steam Generator 2 Wide-range Level	SGS-046
Steam Generator 2 Wide-range Level	SGS-047
Pressurizer Water Level	RCS-305A
Pressurizer Water Level	RCS-305B
Containment Temperature	VCS-053A
Containment Temperature	VCS-053B
Core Exit Temperature	IIS-009
Core Exit Temperature	IIS-013
Core Exit Temperature	IIS-030
Core Exit Temperature	IIS-034

Table 2.5.1-4
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the DAS is as described in the Design Description of this Section 2.5.1.	Inspection of the as-built system will be performed.	The as-built DAS conforms with the functional arrangement as described in the Design Description of this Section 2.5.1.
2.a) The DAS provides an automatic reactor trip on low wide-range steam generator water level or on low pressurizer water level separate from the PMS.	Electrical power to the PMS equipment will be disconnected and an operational test of the as-built DAS will be performed using real or simulated test signals.	The field breakers of the control rod motor-generator sets open after the test signal reaches the specified limit.
2.b) The DAS provides automatic actuation of selected functions, as identified in Table 2.5.1-1, separate from the PMS.	Electrical power to the PMS equipment will be disconnected and an operational test of the as-built DAS will be performed using real or simulated test signals.	Appropriate DAS output signals are generated after the test signal reaches the specified limit.
2.c) The DAS provides manual initiation of reactor trip, and selected functions, as identified in Table 2.5.1-2, separate from the PMS. These manual initiation functions are implemented in a manner that bypasses the control room multiplexers, the PMS cabinets, and the signal processing equipment of the DAS.	Electrical power to the control room multiplexers and PMS equipment will be disconnected and the outputs from the DAS signal processing equipment will be disabled. While in this configuration, an operational test of the as-built system will be performed using the DAS manual actuation controls.	i) The field breakers of the control rod motor-generator sets open after reactor and turbine trip manual initiation controls are actuated. ii) DAS output signals are generated for the selected functions, as identified in Table 2.5.1-2, after manual initiation controls are actuated.
2.d) The DAS provides MCR displays of selected plant parameters, as identified in Table 2.5.1-3, separate from the PMS.	Electrical power to the PMS equipment will be disconnected and inspection will be performed for retrievability of the selected plant parameters in the MCR.	The selected plant parameters can be retrieved in the MCR.

Table 2.5.1-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3.a) The signal processing hardware of the DAS uses input modules, output modules, and microprocessor boards that are different than those used in the PMS.	Inspection of the as-built DAS and PMS signal processing hardware will be performed.	The DAS signal processing equipment uses input modules, output modules, and micro-processor boards that are different than those used in the PMS. The difference may be a different design, use of different component types, or different manufacturers.
3.b) The display hardware of the DAS uses a different display device than that used in the PMS.	Inspection of the as-built DAS and PMS display hardware will be performed.	The DAS display hardware is different than the display hardware used in the PMS. The difference may be a different design, use of different component types, or different manufacturers.
3.c) Software used in the DAS uses an operating system and a programming language that are different than those used in the PMS.	Inspection of the DAS and PMS design documentation will be performed.	The DAS operating system and programming language are different than those used in the PMS.
3.d) The DAS has electrical surge withstand capability (SWC), and can withstand the electromagnetic interference (EMI), radio frequency (RFI), and electrostatic discharge (ESD) conditions that exist where the DAS equipment is located in the plant.	Type tests, analyses, or a combination of type tests and analyses will be performed on the equipment.	A report exists and concludes that the DAS equipment can withstand the SWC, EMI, RFI and ESD conditions that exist where the DAS equipment is located in the plant.
3.e) The sensors identified on Table 2.5.1-3 are used for DAS input and are separate from those being used by the PMS and plant control system.	Inspection of the as-built system will be performed.	The sensors identified on Table 2.5.1-3 are used by DAS and are separate from those being used by the PMS and plant control system.
3.f) The DAS is powered by non-Class 1E uninterruptible power supplies that are independent and separate from the power supplies which power the PMS.	Electrical power to the PMS equipment will be disconnected. While in this configuration, a test will be performed by providing simulated test signals in the non-Class 1E uninterruptible power supplies.	A simulated test signal exists at the DAS equipment when the assigned non-Class 1E uninterruptible power supply is provided the test signal.

Table 2.5.1-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3.g) The DAS signal processing cabinets are provided with the capability for channel testing without actuating the controlled components.	Channel tests will be performed on the as built system.	The capability exists for testing individual DAS channels without propagating an actuation signal to a DAS controlled component.
3.h) The DAS equipment can withstand the room ambient temperature and humidity conditions that will exist at the plant locations in which the DAS equipment is installed at the times for which the DAS is designed to be operational.	Type tests, analyses, or a combination of type tests and analyses will be performed on the equipment.	A report exists and concludes that the DAS equipment can withstand the room ambient temperature and humidity conditions that will exist at the plant locations in which the DAS equipment is installed at the times for which the DAS is designed to be operational.
4. The DAS hardware and software is developed using a planned design process which provides for specific design documentation and reviews during the following life cycle stages: a) Design requirements phase b) System definition phase c) Hardware and software development phase d) System test phase e) Installation phase The planned design process also provides for the use of commercial off-the-shelf hardware and software.	Inspection will be performed of the process used to design the hardware and software.	A report exists and concludes that the process defines the organizational responsibilities, activities, and configuration management controls for the following: a) Establishments of plans and methodologies during the design requirements phase. b) Specification of functional requirements during the system definition phase. c) Documentation and review of hardware and software during the hardware and software development phase. d) Performance of tests and the documentation of test results during the system test phase. e) Performance of tests and inspections during the installation phase. The process also defines requirements for the use of commercial off-the-shelf hardware and software.

Table 2.5.1-5		
Component Name	**Tag No.**	**Component Location**
DAS Processor Cabinet 1	DAS-JD-001	Annex Building
DAS Processor Cabinet 2	DAS-JD-002	Annex Building

2.5.2 Protection and Safety Monitoring System

Design Description

The protection and safety monitoring system (PMS) initiates reactor trip and actuation of engineered safety features in response to plant conditions monitored by process instrumentation and provides safety-related displays. The PMS has the equipment identified in Table 2.5.2-1. The PMS has four divisions of Reactor Trip and Engineered Safety Features Actuation, and two divisions of safety-related post-accident parameter displays. The functional arrangement of the PMS is depicted in Figure 2.5.2-1 and the component locations of the PMS are as shown in Table 2.5.2-9.

1. The functional arrangement of the PMS is as described in the Design Description of this Section 2.5.2.

2. The seismic Category I equipment, identified in Table 2.5.2-1, can withstand seismic design basis loads without loss of safety function.

3. The Class 1E equipment, identified in Table 2.5.2-1, has electrical surge withstand capability (SWC), and can withstand the electromagnetic interference (EMI), radio frequency interference (RFI), and electrostatic discharge (ESD) conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.

4. The Class 1E equipment, identified in Table 2.5.2-1, can withstand the room ambient temperature, humidity, pressure, and mechanical vibration conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.

5. a) The Class 1E equipment, identified in Table 2.5.2-1, is powered from its respective Class 1E division.

   b) Separation is provided between PMS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.

6. The PMS provides the following safety-related functions:

   a) The PMS initiates an automatic reactor trip, as identified in Table 2.5.2-2, when plant process signals reach specified limits.

   b) The PMS initiates automatic actuation of engineered safety features, as identified in Table 2.5.2-3, when plant process signals reach specified limits.

   c) The PMS provides manual initiation of reactor trip and selected engineered safety features as identified in Table 2.5.2-4.

7. The PMS provides the following nonsafety-related functions:

   a) The PMS provides process signals to the plant control system (PLS) through isolation devices.

b) The PMS provides process signals to the data display and processing system (DDS) through isolation devices.

c) Data communication between safety and nonsafety systems does not inhibit the performance of the safety function.

d) The PMS ensures that the automatic safety function and the Class 1E manual controls both have priority over the non-Class 1E soft controls.

8. The PMS, in conjunction with the operator workstations, provides the following functions:

a) The PMS provides for the minimum inventory of displays, visual alerts, and fixed position controls, as identified in Table 2.5.2-5. The plant parameters listed with a "Yes" in the "Display" column and visual alerts listed with a "Yes" in the "Alert" column can be retrieved in the main control room (MCR). The fixed position controls listed with a "Yes" in the "Control" column are provided in the MCR.

b) The PMS provides for the transfer of control capability from the MCR to the remote shutdown workstation (RSW) using multiple transfer switches. Each individual transfer switch is associated with only a single safety-related group or with nonsafety-related control capability.

c) Displays of the open/closed status of the reactor trip breakers can be retrieved in the MCR.

9. a) The PMS automatically removes blocks of reactor trip and engineered safety features actuation when the plant approaches conditions for which the associated function is designed to provide protection. These blocks are identified in Table 2.5.2-6.

b) The PMS two-out-of-four initiation logic reverts to a two-out-of-three coincidence logic if one of the four channels is bypassed. All bypassed channels are alarmed in the MCR.

c) The PMS does not allow simultaneous bypass of two redundant channels.

d) The PMS provides the interlock functions identified in Table 2.5.2-7.

10. Setpoints are determined using a methodology which accounts for loop inaccuracies, response testing, and maintenance or replacement of instrumentation.

11. The PMS hardware and software is developed using a planned design process which provides for specific design documentation and reviews during the following life cycle stages:

a) Design requirements phase, may be referred to as conceptual or project definition phase

b) System definition phase

c) Hardware and software development phase, consisting of hardware and software design and implementation

d) System integration and test phase

e) Installation phase

12. The PMS software is designed, tested, installed, and maintained using a process which incorporates a graded approach according to the relative importance of the software to safety and specifies requirements for:

 a) Software management including documentation requirements, standards, review requirements, and procedures for problem reporting and corrective action.

 b) Software configuration management including historical records of software and control of software changes.

 c) Verification and validation including requirements for reviewer independence.

13. The use of commercial grade hardware and software items in the PMS is accomplished through a process that specifies requirements for:

 a) Review of supplier design control, configuration management, problem reporting, and change control.

 b) Review of product performance.

 c) Receipt acceptance of the commercial grade item.

 d) Final acceptance based on equipment qualification and software validation in the integrated system.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.5.2-8 specifies the inspections, tests, analyses, and associated acceptance criteria for the PMS.

Table 2.5.2-1
PMS Equipment Name and Classification

Equipment Name	Seismic Cat. I	Class 1E	Qual. for Harsh Envir.
PMS Cabinets, Division A	Yes	Yes	No
PMS Cabinets, Division B	Yes	Yes	No
PMS Cabinets, Division C	Yes	Yes	No
PMS Cabinets, Division D	Yes	Yes	No
Reactor Trip Switchgear, Division A	Yes	Yes	No
Reactor Trip Switchgear, Division B	Yes	Yes	No
Reactor Trip Switchgear, Division C	Yes	Yes	No
Reactor Trip Switchgear, Division D	Yes	Yes	No
MCR/RSW Transfer Panels	Yes	Yes	No
MCR Safety-related Display, Division B	Yes	Yes	No
MCR Safety-related Display, Division C	Yes	Yes	No
MCR Safety-related Controls	Yes	Yes	No

Table 2.5.2-2 PMS Automatic Reactor Trips
Source Range High Neutron Flux Reactor Trip Intermediate Range High Neutron Flux Reactor Trip Power Range High Neutron Flux (Low Setpoint) Trip Power Range High Neutron Flux (High Setpoint) Trip Power Range High Positive Flux Rate Trip Reactor Coolant Pump High Bearing Water Temperature Trip Overtemperature Delta-T Trip Overpower Delta-T Trip Pressurizer Low Pressure Trip Pressurizer High Pressure Trip Pressurizer High Water Level Trip Low Reactor Coolant Flow Trip Low Reactor Coolant Pump Speed Trip Low Steam Generator Water Level Trip High-2 Steam Generator Water Level Trip Automatic or Manual Safeguards Actuation Trip Automatic or Manual Depressurization System Actuation Trip Automatic or Manual Core Makeup Tank (CMT) Injection Trip

Table 2.5.2-3 PMS Automatically Actuated Engineered Safety Features
Safeguards Actuation Containment Isolation Automatic Depressurization System (ADS) Actuation Main Feedwater Isolation Reactor Coolant Pump Trip CMT Injection Turbine Trip (Isolated signal to nonsafety equipment) Steam Line Isolation Steam Generator Relief Isolation Steam Generator Blowdown Isolation Passive Containment Cooling Actuation Startup Feedwater Isolation Passive Residual Heat Removal (PRHR) Heat Exchanger Alignment Block of Boron Dilution Chemical and Volume Control System (CVS) Makeup Line Isolation Steam Dump Block (Isolated signal to nonsafety equipment) MCR Isolation and Air Supply Initiation Auxiliary Spray and Letdown Purification Line Isolation Containment Air Filtration System Isolation Normal Residual Heat Removal Isolation Refueling Cavity Isolation In-Containment Refueling Water Storage Tank (IRWST) Injection IRWST Containment Recirculation CVS Letdown Isolation Pressurizer Heater Block (Isolated signal to nonsafety equipment)

Table 2.5.2-4 PMS Manually Actuated Functions
Reactor Trip
Safeguards Actuation
Containment Isolation
Depressurization System Stages 1, 2, and 3 Actuation
Depressurization System Stage 4 Actuation
Feedwater Isolation
Core Makeup Tank Injection Actuation
Steam Line Isolation
Passive Containment Cooling Actuation
Passive Residual Heat Removal Heat Exchanger Alignment
IRWST Injection
Containment Recirculation Actuation
Control Room Isolation and Air Supply Initiation
Steam Generator Relief Isolation
Chemical and Volume Control System Isolation
Normal Residual Heat Removal System Isolation

Table 2.5.2-5
Minimum Inventory of Displays, Alerts, and Fixed Position Controls in the MCR

Description	Control	Display	Alert[1]
Neutron Flux	-	Yes	Yes
Neutron Flux Doubling	-	No	Yes
Startup Rate	-	Yes	Yes
Reactor Coolant System (RCS) Pressure	-	Yes	Yes
Wide-range Hot Leg Temperature	-	Yes	No
Wide-range Cold Leg Temperature	-	Yes	Yes
RCS Cooldown Rate Compared to the Limit Based on RCS Pressure	-	Yes	Yes
Wide-range Cold Leg Temperature Compared to the Limit Based on RCS Pressure	-	Yes	Yes
Change of RCS Temperature by more than 5°F in the last 10 minutes	-	No	Yes
Containment Water Level	-	Yes	Yes
Containment Pressure	-	Yes	Yes
Pressurizer Water Level	-	Yes	Yes
Pressurizer Water Level Trend	-	Yes	No
Pressurizer Reference Leg Temperature	-	Yes	No
Reactor Vessel-Hot Leg Water Level	-	Yes	Yes
Pressurizer Pressure	-	Yes	No
Core Exit Temperature	-	Yes	Yes
RCS Subcooling	-	Yes	Yes
RCS Cold Overpressure Limit	-	Yes	Yes
IRWST Water Level	-	Yes	Yes
PRHR Flow	-	Yes	Yes
PRHR Outlet Temperature	-	Yes	Yes

Note: Dash (-) indicates not applicable.

1. These parameters are used to generate visual alerts that identify challenges to the critical safety functions. For the main control room, the visual alerts are embedded in the safety-related displays as visual signals.

Table 2.5.2-5 (cont.)
Minimum Inventory of Displays, Alerts, and Fixed Position Controls in the MCR

Description	Control	Display	Alert(1)
Passive Containment Cooling System (PCS) Storage Tank Water Level	-	Yes	No
PCS Cooling Flow	-	Yes	No
IRWST to Normal Residual Heat Removal System (RNS) Suction Valve Status	-	Yes	Yes
Remotely Operated Containment Isolation Valve Status(2)	-	Yes	No
Containment Area High-range Radiation Level	-	Yes	Yes
Containment Pressure (Extended Range)	-	Yes	No
CMT Level	-	Yes	No
Manual Reactor Trip (also initiates turbine trip)	Yes	-	-
Manual Safeguards Actuation	Yes	-	-
Manual CMT Actuation	Yes	-	-
Manual MCR Emergency Habitability System Actuation	Yes	-	-
Manual ADS Stages 1, 2, and 3 Actuation	Yes	-	-
Manual ADS Stage 4 Actuation	Yes	-	-
Manual PRHR Actuation	Yes	-	-
Manual Containment Cooling Actuation	Yes	-	-
Manual IRWST Injection Actuation	Yes	-	-
Manual Containment Recirculation Actuation	Yes	-	-
Manual Containment Isolation	Yes	-	-
Manual Main Steam Line Isolation	Yes	-	-
Manual Feedwater Isolation	Yes	-	-
Manual Containment Hydrogen Igniter (Nonsafety-related)	Yes	-	-

Note: Dash (-) indicates not applicable.

2. These instruments are not required after 24 hours.

Table 2.5.2-6 PMS Blocks
Reactor Trip Functions: Source Range High Neutron Flux Reactor Trip Intermediate Range High Neutron Flux Reactor Trip Power Range High Neutron Flux (Low Setpoint) Trip Reactor Coolant Pump High Bearing Water Temperature Trip Pressurizer Low Pressure Trip Pressurizer High Water Level Trip Low Reactor Coolant Flow Trip Low Reactor Coolant Pump Speed Trip High Steam Generator Water Level Trip Engineered Safety Features: Automatic Safeguards Containment Isolation Main Feedwater Isolation Reactor Coolant Pump Trip Core Makeup Tank Injection Turbine Trip Steam Line Isolation Startup Feedwater Isolation Block of Boron Dilution Chemical and Volume Control System Isolation Steam Dump Block Auxiliary Spray and Letdown Purification Line Isolation Passive Residual Heat Removal Heat Exchanger Alignment Normal Residual Heat Removal System Isolation Plant Control System Blocks (Nonsafety-related): Automatic Rod Withdrawal

Table 2.5.2-7 PMS Interlocks
RNS Suction Valves PRHR Heat Exchanger Inlet Isolation Valve CMT Cold Leg Balance Line Isolation Valves

Table 2.5.2-8
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the PMS is as described in the Design Description of this Section 2.5.2.	Inspection of the as-built system will be performed.	The as-built PMS conforms with the functional arrangement as described in the Design Description of this Section 2.5.2.
2. The seismic Category I equipment, identified in Table 2.5.2-1, can withstand seismic design basis loads without loss of safety function.	i) Inspection will be performed to verify that the seismic Category I equipment identified in Table 2.5.2-1 is located on the Nuclear Island. ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed. iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	i) The seismic Category I equipment identified in Table 2.5.2-1 is located on the Nuclear Island. ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis loads without loss of safety function. iii) A report exists and concludes that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.
3. The Class 1E equipment, identified in Table 2.5.2-1, has electrical surge withstand capability (SWC), and can withstand the electromagnetic interference (EMI), radio frequency interference (RFI), and electrostatic discharge (ESD) conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.	Type tests, analyses, or a combination of type tests and analyses will be performed on the equipment.	A report exists and concludes that the Class 1E equipment identified in Table 2.5.2-1 can withstand the SWC, EMI, RFI, and ESD conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.

Table 2.5.2-8 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4. The Class 1E equipment, identified in Table 2.5.2-1, can withstand the room ambient temperature, humidity, pressure, and mechanical vibration conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.	Type tests, analyses, or a combination of type tests and analyses will be performed on the Class 1E equipment identified in Table 2.5.2-1.	A report exists and concludes that the Class 1E equipment identified in Table 2.5.2-1 can withstand the room ambient temperature, humidity, pressure, and mechanical vibration conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.
5.a) The Class 1E equipment, identified in Table 2.5.2-1, is powered from its respective Class 1E division.	Tests will be performed by providing a simulated test signal in each Class 1E division.	A simulated test signal exists at the Class 1E equipment identified in Table 2.5.2-1 when the assigned Class 1E division is provided the test signal.
5.b) Separation is provided between PMS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.	See Tier 1 Material, Table 3.3-6, items 7.d and 7.e.	See Tier 1 Material, Table 3.3-6, items 7.d and 7.e.
6.a) The PMS initiates an automatic reactor trip, as identified in Table 2.5.2-2, when plant process signals reach specified limits.	An operational test of the as-built PMS will be performed using real or simulated test signals.	i) The reactor trip switchgear opens after the test signal reaches the specified limit. This only needs to be verified for one automatic reactor trip function. ii) PMS output signals to the reactor trip switchgear are generated after the test signal reaches the specified limit. This needs to be verified for each automatic reactor trip function.
6.b) The PMS initiates automatic actuation of engineered safety features, as identified in Table 2.5.2-3, when plant process signals reach specified limits.	An operational test of the as-built PMS will be performed using real or simulated test signals.	Appropriate PMS output signals are generated after the test signal reaches the specified limit. These output signals remain following removal of the test signal. Tests from the actuation signal to the actuated device(s) are performed as part of the system-related inspection, test, analysis, and acceptance criteria.

Table 2.5.2-8 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6.c) The PMS provides manual initiation of reactor trip and selected engineered safety features as identified in Table 2.5.2-4.	An operational test of the as-built PMS will be performed using the PMS manual actuation controls.	i) The reactor trip switchgear opens after manual reactor trip controls are actuated. ii) PMS output signals are generated for reactor trip and selected engineered safety features as identified in Table 2.5.2-4 after the manual initiation controls are actuated.
7.a) The PMS provides process signals to the PLS through isolation devices.	Type tests, analyses, or a combination of type tests and analyses of the isolation devices will be performed.	A report exists and concludes that the isolation devices prevent credible faults from propagating into the PMS.
7.b) The PMS provides process signals to the DDS through isolation devices.	Type tests, analyses, or a combination of type tests and analyses of the isolation devices will be performed.	A report exists and concludes that the isolation devices prevent credible faults from propagating into the PMS.
7.c) Data communication between safety and nonsafety systems does not inhibit the performance of the safety function.	Type tests, analyses, or a combination of type tests and analyses of the PMS gateways will be performed.	A report exists and concludes that data communication between safety and nonsafety systems does not inhibit the performance of the safety function.
7.d) The PMS ensures that the automatic safety function and the Class 1E manual controls both have priority over the non-Class 1E soft controls.	Type tests, analyses, or a combination of type tests and analyses of the PMS manual control circuits and algorithms will be performed.	A report exists and concludes that the automatic safety function and the Class 1E manual controls both have priority over the non-Class 1E soft controls.

Table 2.5.2-8 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
8.a) The PMS provides for the minimum inventory of displays, visual alerts, and fixed position controls, as identified in Table 2.5.2-5. The plant parameters listed with a "Yes" in the "Display" column and visual alerts listed with a "Yes" in the "Alert" column can be retrieved in the MCR. The fixed position controls listed with a "Yes" in the "Control" column are provided in the MCR.	i) An inspection will be performed for retrievability of plant parameters in the MCR.	i) The plant parameters listed in Table 2.5.2-5 with a "Yes" in the "Display" column, can be retrieved in the MCR.
	ii) An inspection and test will be performed to verify that the plant parameters are used to generate visual alerts that identify challenges to critical safety functions.	ii) The plant parameters listed in Table 2.5.2-5 with a "Yes" in the "Alert" column are used to generate visual alerts that identify challenges to critical safety functions. The visual alerts actuate in accordance with their correct logic and values.
	iii) An operational test of the as-built system will be performed using each MCR fixed position control.	iii) For each test of an as-built fixed position control listed in Table 2.5.2-5 with a "Yes" in the "Control" column, an actuation signal is generated. Tests from the actuation signal to the actuated device(s) are performed as part of the system-related inspection, test, analysis and acceptance criteria.
8.b) The PMS provides for the transfer of control capability from the MCR to the RSW using multiple transfer switches. Each individual transfer switch is associated with only a single safety-related group or with nonsafety-related control capability.	i) An inspection will be performed to verify that a transfer switch exists for each safety-related division and the nonsafety-related control capability.	i) A transfer switch exists for each safety-related division and the nonsafety-related control capability.
	ii) An operational test of the as-built system will be performed to demonstrate the transfer of control capability from the MCR to the RSW.	ii) Actuation of each transfer switch results in an alarm in the MCR and RSW, the activation of operator control capability from the RSW, and the deactivation of operator control capability from the MCR for the associated safety-related division and nonsafety-related control capability.
8.c) Displays of the open/closed status of the reactor trip breakers can be retrieved in the MCR.	Inspection will be performed for retrievability of displays of the open/closed status of the reactor trip breakers in the MCR.	Displays of the open/closed status of the reactor trip breakers can be retrieved in the MCR.

Table 2.5.2-8 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9.a) The PMS automatically removes blocks of reactor trip and engineered safety features actuation when the plant approaches conditions for which the associated function is designed to provide protection. These blocks are identified in Table 2.5.2-6.	An operational test of the as-built PMS will be performed using real or simulated test signals.	The PMS blocks are automatically removed when the test signal reaches the specified limit.
9.b) The PMS two-out-of-four initiation logic reverts to a two-out-of-three coincidence logic if one of the four channels is bypassed. All bypassed channels are alarmed in the MCR.	An operational test of the as-built PMS will be performed.	The PMS two-out-of-four initiation logic reverts to a two-out-of-three coincidence logic if one of the four channels is bypassed. All bypassed channels are alarmed in the MCR.
9.c) The PMS does not allow simultaneous bypass of two redundant channels.	An operational test of the as-built PMS will be performed. With one channel in bypass, an attempt will be made to place a redundant channel in bypass.	The redundant channel cannot be placed in bypass.
9.d) The PMS provides the interlock functions identified in Table 2.5.2-7.	An operational test of the as-built PMS will be performed using real or simulated test signals.	Appropriate PMS output signals are generated as the interlock conditions are changed.
10. Setpoints are determined using a methodology which accounts for loop inaccuracies, response testing, and maintenance or replacement of instrumentation.	Inspection will be performed for a document that describes the methodology and input parameters used to determine the PMS setpoints.	A report exists and concludes that the PMS setpoints are determined using a methodology which accounts for loop inaccuracies, response testing, and maintenance or replacement of instrumentation.

Table 2.5.2-8 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
11. The PMS hardware and software is developed using a planned design process which provides for specific design documentation and reviews during the following life cycle stages: a) Design requirements phase, may be referred to as conceptual or project definition phase b) System definition phase c) Hardware and software development phase, consisting of hardware and software design and implementation d) System integration and test phase e) Installation phase	Inspection will be performed of the process used to design the hardware and software.	A report exists and concludes that the process defines the organizational responsibilities, activities, and configuration management controls for the following: a) Establishment of plans and methodologies. b) Specification of functional requirements. c) Documentation and review of hardware and software. d) Performance of system tests and the documentation of system test results. e) Performance of installation tests and inspections.

Table 2.5.2-8 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
12. The PMS software is designed, tested, installed, and maintained using a process which incorporates a graded approach according to the relative importance of the software to safety and specifies requirements for: a) Software management including documentation requirements, standards, review requirements, and procedures for problem reporting and corrective action. b) Software configuration management including historical records of software and control of software changes. c) Verification and validation including requirements for reviewer independence.	Inspection will be performed of the process used to design, test, install, and maintain the PMS software.	A report exists and concludes that the process establishes a method for classifying the PMS software elements according to their relative importance to safety and specifies requirements for software assigned to each safety classification. The report also concludes that requirements are provided for the following software development functions: a) Software management including documentation requirements, standards, review requirements, and procedures for problem reporting and corrective action. Software management requirements may be documented in the software quality assurance plan, software management plan, software development plan, software safety plan, and software operation and maintenance plan; or these requirements may be combined into a single software management plan. b) Software configuration management including historical records of software and control of software changes. Software configuration management requirements are provided in the software configuration management plan. c) Verification and validation including requirements for reviewer independence. Verification and validation requirements are provided in the verification and validation plan.

Table 2.5.2-8 (cont.) Inspections, Tests, Analyses, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
13. The use of commercial grade computer hardware and software items in the PMS is accomplished through a process that specifies requirements for: a) Review of supplier design control, configuration management, problem reporting, and change control. b) Review of product performance. c) Receipt acceptance of the commercial grade item. d) Acceptance based on equipment qualification and software validation in the integrated system.	Inspection will be performed of the process defined to use commercial grade components in the application.	A report exists and concludes that the process has requirements for: a) Review of supplier design control, configuration management, problem reporting, and change control. b) Review of product performance. c) Receipt acceptance of the commercial grade item. d) Acceptance based on equipment qualification and software validation in the integrated system.

Table 2.5.2-9	
Component Name	**Component Location**
PMS Cabinets, Division A	Auxiliary Building
PMS Cabinets, Division B	Auxiliary Building
PMS Cabinets, Division C	Auxiliary Building
PMS Cabinets, Division D	Auxiliary Building
Reactor Trip Switchgear, Division A	Auxiliary Building
Reactor Trip Switchgear, Division B	Auxiliary Building
Reactor Trip Switchgear, Division C	Auxiliary Building
Reactor Trip Switchgear, Division D	Auxiliary Building
MCR/RSW Transfer Panels	Auxiliary Building
MCR Safety-related Displays	Auxiliary Building
MCR Safety-related Controls	Auxiliary Building

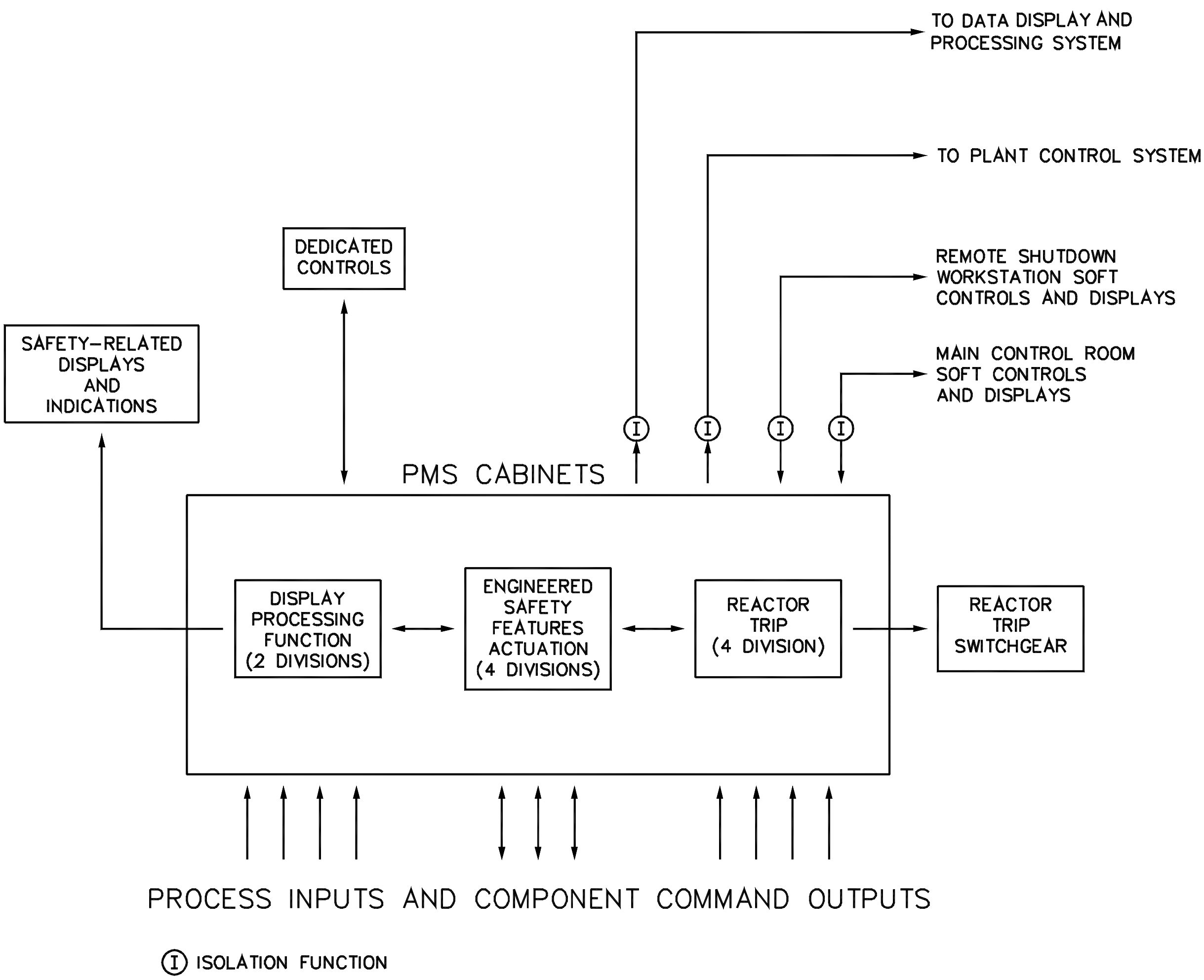


Figure 2.5.2-1
Protection and Safety Monitoring System

2.5.3 Plant Control System

Design Description

The plant control system (PLS) provides for automatic and manual control of nonsafety-related plant components during normal and emergency plant operations. The PLS has distributed controllers and operator controls interconnected by computer data links or data highways.

1. The functional arrangement of the PLS is as described in the Design Description of this Section 2.5.3.

2. The PLS provides control interfaces for the control functions listed in Table 2.5.3-1.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.5.3-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the PLS.

Table 2.5.3-1
Control Functions Supported by the PLS

1. Reactor Power
2. Reactor Rod Position
3. Pressurizer Pressure
4. Pressurizer Water Level
5. Steam Generator Feedwater
6. Steam Dump
7. Rapid Power Reduction

Table 2.5.3-2
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the PLS is as described in the Design Description of this Section 2.5.3.	Inspection of the as-built system will be performed.	The as-built PLS conforms with the functional arrangement as described in the Design Description of this Section 2.5.3.
2. The PLS provides control interfaces for the control functions listed in Table 2.5.3-1.	An operational test of the system will be performed using simulated input signals. System outputs or component operations will be monitored to determine the operability of the control functions.	The PLS provides control interfaces for the control functions listed in Table 2.5.3-1.

2.5.4 Data Display and Processing System

Design Description

The data display and processing system (DDS) provides nonsafety-related alarms and displays, analysis of plant data, plant data logging and historical storage and retrieval, and operational support for plant personnel. The DDS has distributed computer processors and video display units to support the data processing and display functions.

1. The functional arrangement of the DDS is as described in the Design Description of this Section 2.5.4.

2. The DDS, in conjunction with the operator workstations, provides the following function:

   The DDS provides for the minimum inventory of displays, visual alerts, and fixed position controls, as identified in Table 2.5.4-1. The plant parameters listed with a "Yes" in the "Display" column and visual alerts listed with a "Yes" in the "Alert" column can be retrieved at the remote shutdown workstation (RSW). The controls listed with a "Yes" in the "Control" column are provided at the RSW.

3. The DDS provides information pertinent to the status of the protection and safety monitoring system.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.5.4-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the DDS.

Table 2.5.4-1
Minimum Inventory of Controls, Displays, and Alerts at the RSW

Description	Control	Display	Alert(1)
Neutron Flux	-	Yes	Yes
Neutron Flux Doubling	-	No	Yes
Startup Rate	-	Yes	Yes
Reactor Coolant System (RCS) Pressure	-	Yes	Yes
Wide-range Hot Leg Temperature	-	Yes	No
Wide-range Cold Leg Temperature	-	Yes	Yes
RCS Cooldown Rate Compared to the Limit Based on RCS Pressure	-	Yes	Yes
Wide-range Cold Leg Temperature Compared to the Limit Based on RCS Pressure	-	Yes	Yes
Change of RCS Temperature by more than 5°F in the last 10 minutes	-	No	Yes
Containment Water Level	-	Yes	Yes
Containment Pressure	-	Yes	Yes
Pressurizer Water Level	-	Yes	Yes
Pressurizer Water Level Trend	-	Yes	No
Pressurizer Reference Leg Temperature	-	Yes	No
Reactor Vessel-Hot Leg Water Level	-	Yes	Yes
Pressurizer Pressure	-	Yes	No
Core Exit Temperature	-	Yes	Yes
RCS Subcooling	-	Yes	Yes
RCS Cold Overpressure Limit	-	Yes	Yes
In-containment Refueling Water Storage Tank (IRWST) Water Level	-	Yes	Yes
Passive Residual Heat Removal (PRHR) Flow	-	Yes	Yes

Note: Dash (-) indicates not applicable.

1. These parameters are used to generate visual alerts that identify challenges to the critical safety functions. For the RSW, the visual alerts are embedded in the nonsafety-related displays as visual signals.

Table 2.5.4-1 (cont.)
Minimum Inventory of Controls, Displays, and Alerts at the RSW

Description	Control	Display	Alert[(1)]
PRHR Outlet Temperature	-	Yes	Yes
Passive Containment Cooling System (PCS) Storage Tank Water Level	-	Yes	No
PCS Cooling Flow	-	Yes	No
IRWST to Normal Residual Heat Removal System (RNS) Suction Valve Status	-	Yes	Yes
Remotely Operated Containment Isolation Valve Status[(2)]	-	Yes	No
Containment Area High-range Radiation Level	-	Yes	Yes
Containment Pressure (Extended Range)	-	Yes	No
Core Makeup Tank (CMT) Level	-	Yes	No
Manual Reactor Trip (also initiates turbine trip)	Yes	-	-
Manual Safeguards Actuation	Yes	-	-
Manual CMT Actuation	Yes	-	-
Manual Automatic Depressurization System (ADS) Stages 1, 2, and 3 Actuation	Yes	-	-
Manual ADS Stage 4 Actuation	Yes	-	-
Manual PRHR Actuation	Yes	-	-
Manual Containment Cooling Actuation	Yes	-	-
Manual IRWST Injection Actuation	Yes	-	-
Manual Containment Recirculation Actuation	Yes	-	-
Manual Containment Isolation	Yes	-	-
Manual Main Steam Line Isolation	Yes	-	-
Manual Feedwater Isolation	Yes	-	-
Manual Containment Hydrogen Igniter (Nonsafety-related)	Yes	-	-

Note: Dash (-) indicates not applicable.

1. These parameters are used to generate visual alerts that identify challenges to the critical safety functions. For the RSW, the visual alerts are embedded in the nonsafety-related displays as visual signals.

2. These instruments are not required after 24 hours.

Table 2.5.4-2
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the DDS is as described in the Design Description of this Section 2.5.4.	Inspection of the as-built system will be performed.	The as-built DDS conforms with the functional arrangement as described in the Design Description of this Section 2.5.4.
2. The DDS provides for the minimum inventory of displays, visual alerts, and fixed position controls, as identified in Table 2.5.4-1. The plant parameters listed with a "Yes" in the "Display" column and visual alerts listed with a "Yes" in the "Alert" column can be retrieved at the RSW. The controls listed with a "Yes" in the "Control" column are provided at the RSW.	i) An inspection will be performed for retrievability of plant parameters at the RSW.	i) The plant parameters listed in Table 2.5.4-1 with a "Yes" in the "Display" column can be retrieved at the RSW.
	ii) An inspection and test will be performed to verify that the plant parameters are used to generate visual alerts that identify challenges to critical safety functions.	ii) The plant parameters listed in Table 2.5.4-1 with a "Yes" in the "Alert" column are used to generate visual alerts that identify challenges to critical safety functions. The visual alerts actuate in accordance with their logic and values.
	iii) An operational test of the as-built system will be performed using each RSW control.	iii) For each test of a control listed in Table 2.5.4-1 with a "Yes" in the "Control" column, an actuation signal is generated. Tests from the actuation signal to the actuated device(s) are performed as part of the system-related inspection, test, analysis and acceptance criteria.
3. The DDS provides information pertinent to the status of the protection and safety monitoring system.	Tests of the as-built system will be performed.	The as-built system provides displays of the bypassed and operable status of the protection and safety monitoring system.

2.5.5 In-Core Instrumentation System

Design Description

The in-core instrumentation system (IIS) provides safety-related core exit thermocouple signals to the protection and safety monitoring system (PMS). The IIS also provides nonsafety-related core exit thermocouple signals to the diverse actuation system (DAS). The core exit thermocouples are housed in the core instrument assemblies. Multiple core instrument assemblies are used to provide radial coverage of the core. At least three core instrument assemblies are provided in each core quadrant.

1. The functional arrangement of the IIS is as described in the Design Description of this Section 2.5.5.

2. The seismic Category I equipment identified in Table 2.5.5-1 can withstand seismic design basis loads without loss of safety function.

3. a) The Class 1E equipment identified in Table 2.5.5-1 as being qualified for a harsh environment can withstand environmental conditions that would exist before, during, and following a design basis accident without loss of safety function, for the time required to perform the safety function.

   b) The Class 1E cables between the Incore Thermocouple elements and the connector boxes located on the integrated head package have sheaths.

   c) For cables other than those covered by 3.b, separation is provided between IIS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.

3. Safety-related displays of the parameters identified in Table 2.5.5-1 can be retrieved in the main control room (MCR).

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.5.5-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the IIS.

Table 2.5.5-1					
Equipment Name	**Seismic Cat. I**	**ASME Code Classification**	**Class 1E**	**Qual. for Harsh Envir.**	**Safety-Related Display**
Incore Thimble Assemblies (at least three assemblies in each core quadrant)	Yes	–	Yes[(1)]	Yes[(1)]	Core Exit Temperature[(1)]

Note: Dash (-) indicates not applicable.

1. Only applies to the safety-related assemblies. There are at least two safety-related assemblies in each core quadrant.

Table 2.5.5-2
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the IIS is as described in the Design Description of this Section 2.5.5.	Inspection of the as-built system will be performed.	The as-built IIS conforms with the functional arrangement as described in the Design Description of this Section 2.5.5.
2. The seismic Category I equipment identified in Table 2.5.5-1 can withstand seismic design basis dynamic loads without loss of safety function.	i) Inspection will be performed to verify that the seismic Category I equipment identified in Table 2.5.5-1 is located on the Nuclear Island.	i) The seismic Category I equipment identified in Table 2.5.5-1 is located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis dynamic loads without loss of safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) A report exists and concludes that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.
3.a) The Class 1E equipment identified in Table 2.5.5-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function, for the time required to perform the safety function.	i) Type tests, analysis, or a combination of type tests and analysis will be performed on Class 1E equipment located in a harsh environment.	i) A report exists and concludes that the Class 1E equipment identified in Table 2.5.5-1 as being qualified for a harsh environment. This equipment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.
	ii) Inspection will be performed of the as-installed Class 1E equipment and the associated wiring, cables, and terminations located in a harsh environment.	ii) A report exists and concludes that the as-installed Class 1E equipment and the associated wiring, cables, and terminations identified in Table 2.5.5-1 as being qualified for a harsh environment are bounded by type tests, analyses, or a combination of type tests and analyses.

Table 2.5.5-2 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3.b) The Class 1E cables between the Incore Thermocouple elements and the connector boxes located on the integrated head package have sheaths.	Inspection of the as-built system will be performed.	The as-built Class 1E cables between the Incore Thermocouple elements and the connector boxes located on the integrated head package have sheaths.
3.c) For cables other than those covered by 3.b, separation is provided between IIS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.	See Tier 1 Material, Table 3.3-6, item 7.d.	See Tier 1 Material, Table 3.3-6, item 7.d.
4. Safety-related displays of the parameters identified in Table 2.5.5-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the safety-related displays in the MCR.	Safety-related displays identified in Table 2.5.5-1 can be retrieved in the MCR.

2.5.6 Special Monitoring System

Design Description

The special monitoring system (SMS) monitors the reactor coolant system (RCS) for the occurrence of impacts characteristic of metallic loose parts. Metal impact monitoring sensors are provided to monitor the RCS at the upper and lower head region of the reactor pressure vessel, and at the reactor coolant inlet region of each steam generator.

1. The functional arrangement of the SMS is as described in the Design Description of this Section 2.5.6.

2. Data obtained from the metal impact monitoring sensors can be retrieved in the main control room (MCR).

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.5.6-1 specifies the inspections, tests, analyses, and associated acceptance criteria for the SMS.

Table 2.5.6-1
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the SMS is as described in the Design Description of this Section 2.5.6.	Inspection of the as-built system will be performed.	The as-built SMS conforms with the functional arrangement as described in the Design Description of this Section 2.5.6.
2. Data obtained from the metal impact monitoring sensors can be retrieved in the MCR.	Inspection will be performed for retrievability of data from the metal impact monitoring sensors in the MCR.	Data obtained from the metal impact monitoring sensors can be retrieved in the MCR.

2.5.7 Operation and Control Centers System

Design Description

The operation and control centers system (OCS) is developed and implemented based upon a human factors engineering (HFE) program. The human system interface (HSI*)* scope includes the design of the OCS and each of the HSI resources. For the purposes of the HFE program, the OCS includes the main control room, remote shutdown workstation, the local control stations, and the associated workstations for each of these centers. Implementation of the HFE program involves the completion of the human factors engineering analyses and plans described in Tier 1 Material Section 3.2, Human Factors Engineering.

Inspections, Tests, Analyses, and Acceptance Criteria

The inspections, tests, analyses, and associated acceptance criteria for the OCS are provided in Table 3.2-1.

2.5.8 Radiation Monitoring System

No entry. Radiation monitoring function covered in Section 3.5, Radiation Monitoring.

2.5.9 Seismic Monitoring System

Design Description

The seismic monitoring system (SJS) provides for the collection of seismic data in digital format, analysis of seismic data, notification of the operator if the ground motion exceeds a threshold value, and notification of the operator (after analysis of data) that a predetermined cumulative absolute velocity (CAV) has been exceeded. The SJS has at least four triaxial acceleration sensor units and a time-history analyzer and recording system. The time-history analyzer and recording system are located in the auxiliary building.

1. The functional arrangement of the SJS is as described in the Design Description of this Section 2.5.9.

2. The SJS can compute CAV and the 5 percent of critical damping response spectrum for frequencies between 1 and 10 Hertz.

3. The SJS has a dynamic range of 0.001g to 1.0g and a frequency range of 0.2 to 50 Hertz.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.5.9-1 specifies the inspections, tests, analyses, and associated acceptance criteria for SJS.

Table 2.5.9-1
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the SJS is as described in the Design Description of this Section 2.5.9.	Inspection of the as-built system will be performed.	The as-built SJS conforms with the functional arrangement as described in the Design Description of this Section 2.5.9.
2. The SJS can compute CAV and the 5 percent of critical damping response spectrum for frequencies between 1 and 10 Hz.	Type tests using simulated input signals, analyses, or a combination of type tests and analyses, of the SJS time-history analyzer and recording system will be performed.	A report exists and concludes that the SJS time-history analyzer and recording system can record data at a sampling rate of at least 200 samples per second, that the pre-event recording time is adjustable from less than or equal to 1.2 seconds to greater than or equal to 15.0 seconds, and that the initiation value is adjustable from less than or equal to 0.002g to greater than or equal to 0.02g.
3. The SJS has a dynamic range of 0.001g to 1.0g and a frequency range of 0.2 to 50 Hertz.	Type tests, analyses, or a combination of type tests and analyses, of the SJS triaxial acceleration sensors will be performed.	A report exists and concludes that the SJS triaxial acceleration sensors have a dynamic range of at least 0.001g to 1.0g and a frequency range of at least 0.2 to 50 Hertz.

2.5.10 Main Turbine Control and Diagnostic System

No entry. Covered in Section 2.4.2, Main Turbine System.

2.6.1 Main ac Power System

Design Description

The main ac power system (ECS) provides electrical ac power to nonsafety-related loads and non-Class 1E power to the Class 1E battery chargers and regulating transformers during normal and off-normal conditions.

The ECS is as shown in Figures 2.6.1-1 and the component locations of the ECS are as shown in Table 2.6.1-5.

1. The functional arrangement of the ECS is as described in the Design Description of this Section 2.6.1.

2. The seismic Category I equipment identified in Table 2.6.1-1 can withstand seismic design basis loads without loss of safety function.

3. a) The Class 1E breaker control power for the equipment identified in Table 2.6.1-1 are powered from their respective Class 1E division.

   b) Separation is provided between ECS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.

4. The ECS provides the following nonsafety-related functions:

   a) The ECS provides the capability for distributing non-Class 1E ac power from onsite sources (ZOS) to nonsafety-related loads listed in Table 2.6.1-2.

   b) The 6900 Vac circuit breakers in switchgear ECS-ES-1 and ECS-ES-2 open after receiving a signal from the onsite standby power system.

   c) Each standby diesel generator 6900 Vac circuit breaker closes after receiving a signal from the onsite standby power system.

   d) Each ancillary diesel generator unit is sized to supply power to long-term safety-related post-accident monitoring loads and control room lighting and ventilation through a regulating transformer; and for one passive containment cooling system (PCS) recirculation pump.

   e) The ECS provides two loss-of-voltage signals to the onsite standby power system (ZOS), one for each diesel-backed 6900 Vac switchgear bus.

   f) The ECS provides a reverse-power trip of the generator circuit breaker which is blocked for at least 15 seconds following a turbine trip.

5. Controls exist in the main control room (MCR) to cause the circuit breakers identified in Table 2.6.1-3 to perform the listed functions.

6. Displays of the parameters identified in Table 2.6.1-3 can be retrieved in the MCR.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.6.1-4 specifies the inspections, tests, analyses, and associated acceptance criteria for the ECS.

Table 2.6.1-1				
Equipment Name	Tag No.	Seismic Category I	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display
Reactor Coolant Pump (RCP) Circuit Breaker	ECS-ES-31	Yes	Yes/No (Trip open only)	No
RCP Circuit Breaker	ECS-ES-32	Yes	Yes/No (Trip open only)	No
RCP Circuit Breaker	ECS-ES-41	Yes	Yes/No (Trip open only)	No
RCP Circuit Breaker	ECS-ES-42	Yes	Yes/No (Trip open only)	No
RCP Circuit Breaker	ECS-ES-51	Yes	Yes/No (Trip open only)	No
RCP Circuit Breaker	ECS-ES-52	Yes	Yes/No (Trip open only)	No
RCP Circuit Breaker	ECS-ES-61	Yes	Yes/No (Trip open only)	No
RCP Circuit Breaker	ECS-ES-62	Yes	Yes/No (Trip open only)	No

Table 2.6.1-2	
Load Description	**Power Source**
Load Center Transformers EK-11, EK-12, EK-13	ZOS-MG-02A
Diesel Oil Transfer Module Enclosure A Electric Unit Heater	ZOS-MG-02A
Diesel Oil Transfer Module Enclosure A Fan	ZOS-MG-02A
Class 1E Division A Regulating Transformer	ZOS-MG-02A
Class 1E Division C Regulating Transformer	ZOS-MG-02A
Diesel Generator Fuel Oil Transfer Pump 1A	ZOS-MG-02A
Diesel Generator Room A Building Standby Exhaust Fans 1A and 2A	ZOS-MG-02A
Diesel Generator Service Module A Air Handling Unit (AHU) 01A Fan	ZOS-MG-02A
Startup Feedwater Pump A	ZOS-MG-02A
Service Water Pump A	ZOS-MG-02A
Service Water Cooling Tower Fan A	ZOS-MG-02A
MCR/Technical Support Center (TSC) AHU A Supply and Return Fans	ZOS-MG-02A
Divisions A/C Class 1E Electrical Room AHU A Supply and Return Fans	ZOS-MG-02A
Divisions B/D Class 1E Electrical Room AHU D Supply and Return Fans	ZOS-MG-02A
Air-cooled Chiller Pump 2	ZOS-MG-02A
Component Cooling Water Pump 1A	ZOS-MG-02A
Air-cooled Chiller 2	ZOS-MG-02A
Chemical and Volume Control System (CVS) Makeup Pump 1A	ZOS-MG-02A
CVS Pump Room Unit Cooler Fan A	ZOS-MG-02A
Normal Residual Heat Removal System (RNS) Pump 1A	ZOS-MG-02A
RNS Pump Room Unit Cooler Fan A	ZOS-MG-02A
Equipment Room AHU Supply and Return Fans	ZOS-MG-02A
Switchgear Room A AHU Supply and Return Fans	ZOS-MG-02A
Non-1E Battery Charger EDS1-DC-1	ZOS-MG-02A
Non-1E Battery Room A Exhaust Fan	ZOS-MG-02A
Non-1E Battery Charger EDS3-DC-1	ZOS-MG-02A

Table 2.6.1-2 (cont.)	
Load Description	**Power Source**
Class 1E Division A Battery Charger 1 (24-hour)	ZOS-MG-02A
Class 1E Division C Battery Charger 1 (24-hour)	ZOS-MG-02A
Class 1E Division C Battery Charger 2 (72-hour)	ZOS-MG-02A
Divisions A/C Class 1E Battery Room Exhaust Fan A	ZOS-MG-02A
Supplemental Air Filtration Unit Fan A	ZOS-MG-02A
Backup Group 4A Pressurizer Heaters	ZOS-MG-02A
Spent Fuel Cooling Pump 1A	ZOS-MG-02A
Load Center Transformers EK-21, EK-22, EK-23	ZOS-MG-02B
Diesel Oil Transfer Module Enclosure B Electric Unit Heater	ZOS-MG-02B
Diesel Oil Transfer Module Enclosure B Fan	ZOS-MG-02B
Class 1E Division B Regulating Transformer	ZOS-MG-02B
Class 1E Division D Regulating Transformer	ZOS-MG-02B
Diesel Generator Fuel Oil Transfer Pump 1B	ZOS-MG-02B
Diesel Generator Room B Building Standby Exhaust Fans 1B and 2B	ZOS-MG-02B
Diesel Generator Service Module B AHU 01B Fan	ZOS-MG-02B
Startup Feedwater Pump B	ZOS-MG-02B
Service Water Pump B	ZOS-MG-02B
Service Water Cooling Tower Fan B	ZOS-MG-02B
MCR/TSC AHU B Supply and Return Fans	ZOS-MG-02B
Divisions B/D Class 1E Electrical Room AHU B Supply and Return Fans	ZOS-MG-02B
Divisions A/C Class 1E Electrical Room AHU C Supply and Return Fans	ZOS-MG-02B
Air-cooled Chiller Pump 3	ZOS-MG-02B
Component Cooling Water Pump 1B	ZOS-MG-02B
Air-cooled Chiller 3	ZOS-MG-02B
CVS Makeup Pump 1B	ZOS-MG-02B
CVS Pump Room Unit Cooler Fan B	ZOS-MG-02B
RNS Pump 1B	ZOS-MG-02B

Table 2.6.1-2 (cont.)	
Load Description	**Power Source**
RNS Pump Room Unit Cooler Fan B	ZOS-MG-02B
Equipment Room B AHU Supply and Return Fans	ZOS-MG-02B
Switchgear Room B AHU Supply and Return Fans	ZOS-MG-02B
Non-1E Battery Charger EDS2-DC-1	ZOS-MG-02B
Non-1E Battery Room B Exhaust Fan	ZOS-MG-02B
Class 1E Division B Battery Charger 1 (24-hour)	ZOS-MG-02B
Class 1E Division B Battery Charger 2 (72-hour)	ZOS-MG-02B
Class 1E Division D Battery Charger 1 (24-hour)	ZOS-MG-02B
Divisions B/D Class 1E Battery Room Exhaust Fan B	ZOS-MG-02B
Supplemental Air Filtration Unit Fan B	ZOS-MG-02B
Backup Group 4B Pressurizer Heaters	ZOS-MG-02B
Spent Fuel Cooling Pump 1B	ZOS-MG-02B

Table 2.6.1-3

Equipment	Tag No.	Display	Control Function
6900 V Switchgear Bus 1	ECS-ES-1	Yes (Bus voltage, breaker position for all breakers on bus)	Yes (Breaker open/close)
6900 V Switchgear Bus 2	ECS-ES-2	Yes (Bus voltage, breaker position for all breakers on bus)	Yes (Breaker open/close)
Unit Auxiliary Transformer A	ZAS-ET-2A	Yes (Secondary Voltage)	No
Unit Auxiliary Transformer B	ZAS-ET-2B	Yes (Secondary Voltage)	No
Reserve Auxiliary Transformer	ZAS-ET-4	Yes (Secondary Voltage)	No

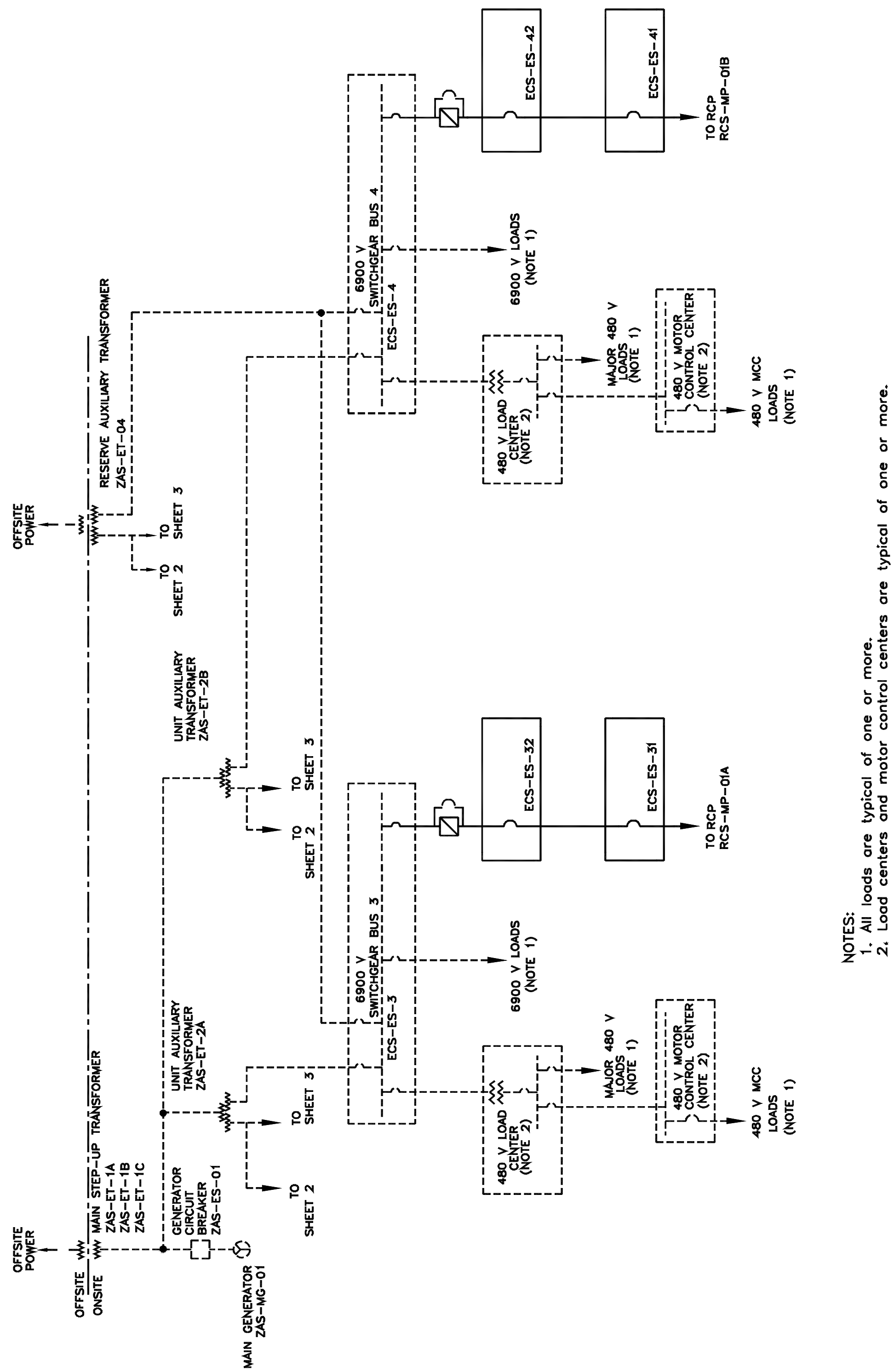
Table 2.6.1-4
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the ECS is as described in the Design Description of this Section 2.6.1.	Inspection of the as-built system will be performed.	The as-built ECS conforms with the functional arrangement as described in the Design Description of this Section 2.6.1.
2. The seismic Category I equipment identified in Table 2.6.1-1 can withstand seismic design basis loads without loss of safety function.	i) Inspection will be performed to verify that the seismic Category I equipment identified in Table 2.6.1-1 is located on the Nuclear Island.	i) The seismic Category I equipment identified in Table 2.6.1-1 is located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis loads without loss of safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) A report exists and concludes that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.
3.a) The Class 1E breaker control power for the equipment identified in Table 2.6.1-1 are powered from their respective Class 1E division.	Testing will be performed on the ECS by providing a simulated test signal in each Class 1E division.	A simulated test signal exists at the Class 1E equipment identified in Table 2.6.1-1 when the assigned Class 1E division is provided the test signal.
3.b) Separation is provided between ECS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.	See Tier 1 Material, Table 3.3-6, item 7.d.	See Tier 1 Material, Table 3.3-6, item 7.d.
4.a) The ECS provides the capability for distributing non-Class 1E ac power from onsite sources (ZOS) to nonsafety-related loads listed in Table 2.6.1-2.	Tests will be performed using a test signal to confirm that an electrical path exists for each selected load listed in Table 2.6.1-2 from an ECS-ES-1 or ECS-ES-2 bus. Each test may be a single test or a series of over-lapping tests.	A test signal exists at the terminals of each selected load.

Table 2.6.1-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4.b) The 6900 Vac circuit breakers in switchgear ECS-ES-1 and ECS-ES-2 open after receiving a signal from the onsite standby power load system.	See Tier 1 Material, Table 2.6.4-1, item 2.a.	See Tier 1 Material, Table 2.6.4-1, item 2.a.
4.c) Each standby diesel generator 6900 Vac circuit breaker closes after receiving a signal from the onsite standby power system.	Testing will be performed using real or simulated signals from the standby diesel load system.	Each standby diesel generator 6900 Vac circuit breaker closes after receiving a signal from the standby diesel system.
4.d) Each ancillary diesel generator unit is sized to supply power to long-term safety-related post-accident monitoring loads and control room lighting and ventilation through a regulating transformer; and for one PCS recirculation pump.	Each ancillary diesel generator will be operated with fuel supplied from the ancillary diesel generator fuel tank and with a load of 35 kW or greater and a power factor between 0.9 and 1.0 for a time period required to reach engine temperature equilibrium plus 2.5 hours.	Each diesel generator provides power to the load with a generator terminal voltage of 480 ± 10% volts and a frequency of 60 ± 5% Hz.
4.e) The ECS provides two loss-of-voltage signals to the onsite standby power system (ZOS), one for each diesel-backed 6900 Vac switchgear bus.	Tests on the as-built ECS system will be conducted by simulating a loss-of-voltage condition on each diesel-backed 6900 Vac switchgear bus.	A loss-of-voltage signal is generated when the loss-of-voltage condition is simulated.
4.f) The ECS provides a reverse-power trip of the generator circuit breaker which is blocked for at least 15 seconds following a turbine trip.	Tests on the as-built ECS system will be conducted by simulating a turbine trip signal followed by a simulated reverse-power condition. The generator circuit breaker trip signal will be monitored.	The generator circuit breaker trip signal does not occur until at least 15 seconds after the simulated turbine trip.
5. Controls exist in the MCR to cause the circuit breakers identified in Table 2.6.1-3 to perform the listed functions.	Tests will be performed to verify that controls in the MCR can operate the circuit breakers identified in Table 2.6.1-3.	Controls in the MCR cause the circuit breakers identified in Table 2.6.1-3 to operate.
6. Displays of the parameters identified in Table 2.6.1-3 can be retrieved in the MCR.	Inspection will be performed for retrievability of the displays identified in Table 2.6.1-3 in the MCR.	Displays identified in Table 2.6.1-3 can be retrieved in the MCR.

Table 2.6.1-5		
Component Name	**Tag No.**	**Component Location**
RCP Circuit Breaker	ECS-ES-31	Auxiliary Building
RCP Circuit Breaker	ECS-ES-32	Auxiliary Building
RCP Circuit Breaker	ECS-ES-41	Auxiliary Building
RCP Circuit Breaker	ECS-ES-42	Auxiliary Building
RCP Circuit Breaker	ECS-ES-51	Auxiliary Building
RCP Circuit Breaker	ECS-ES-52	Auxiliary Building
RCP Circuit Breaker	ECS-ES-61	Auxiliary Building
RCP Circuit Breaker	ECS-ES-62	Auxiliary Building
6900 V Switchgear Bus 1	ECS-ES-1	Annex Building
6900 V Switchgear Bus 2	ECS-ES-2	Annex Building
6900 V Switchgear Bus 3	ECS-ES-3	Turbine Building
6900 V Switchgear Bus 4	ECS-ES-4	Turbine Building
6900 V Switchgear Bus 5	ECS-ES-5	Turbine Building
6900 V Switchgear Bus 6	ECS-ES-6	Turbine Building
Main Generator	ZAS-MG-01	Turbine Building
Generator Circuit Breaker	ZAS-ES-01	Turbine Building
Main Step-up Transformer	ZAS-ET-1A	Yard
Main Step-up Transformer	ZAS-ET-1B	Yard
Main Step-up Transformer	ZAS-ET-1C	Yard
Unit Auxiliary Transformer A	ZAS-ET-2A	Yard
Unit Auxiliary Transformer B	ZAS-ET-2B	Yard
Reserve Auxiliary Transformer	ZAS-ET-4	Yard
Ancillary Diesel Generator #1	ECS-MG-01	Annex Building
Ancillary Diesel Generator #2	ECS-MG-02	Annex Building
Ancillary Diesel Generator Distribution Panel 1	ECS-ED-01	Annex Building
Ancillary Diesel Generator Distribution Panel 1	ECS-ED-02	Annex Building



NOTES:
1. All loads are typical of one or more.
2. Load centers and motor control centers are typical of one or more.

Figure 2.6.1-1 (Sheet 1 of 4)
Main ac Power System

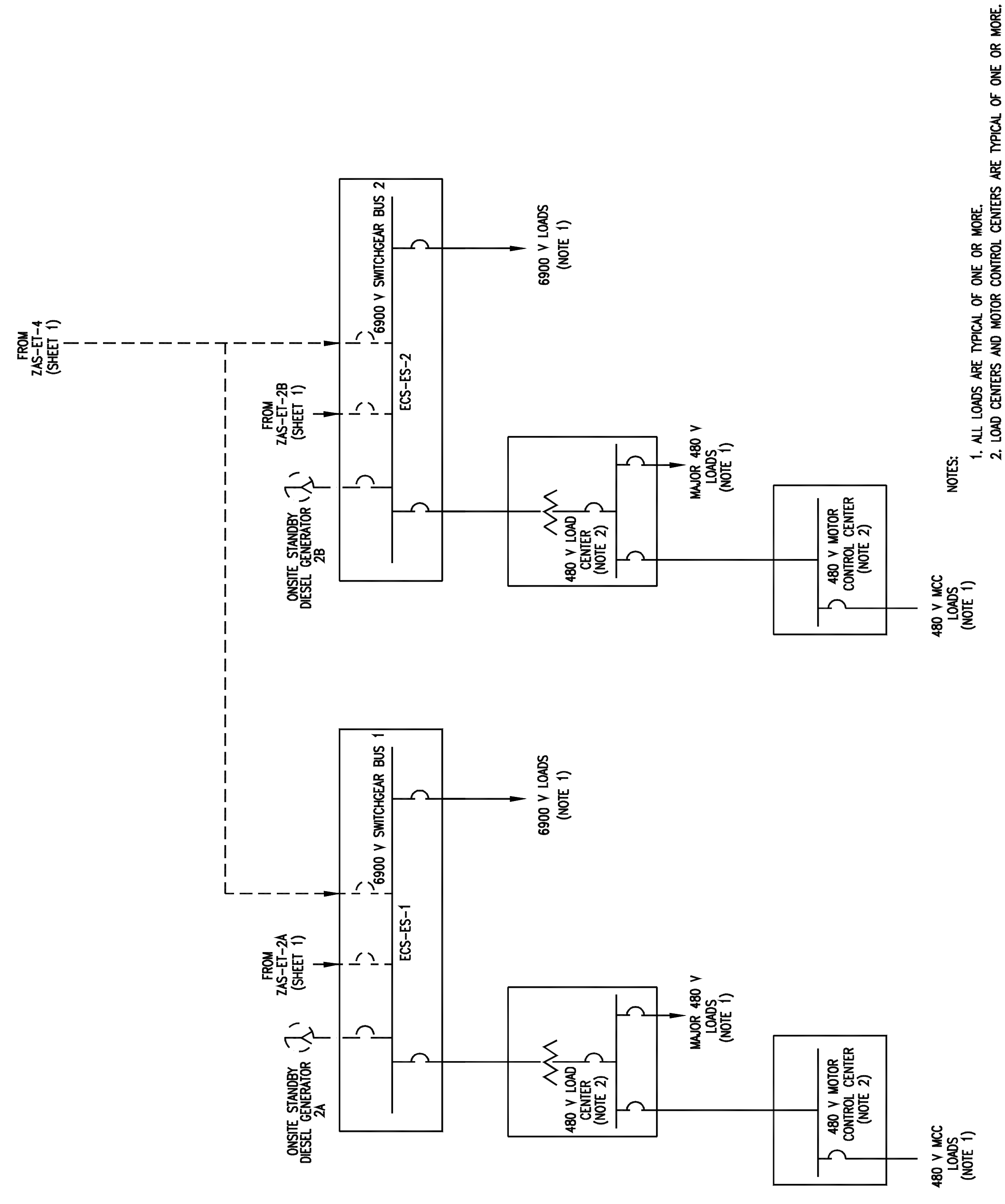


Figure 2.6.1-1 (Sheet 2 of 4)
Main ac Power System

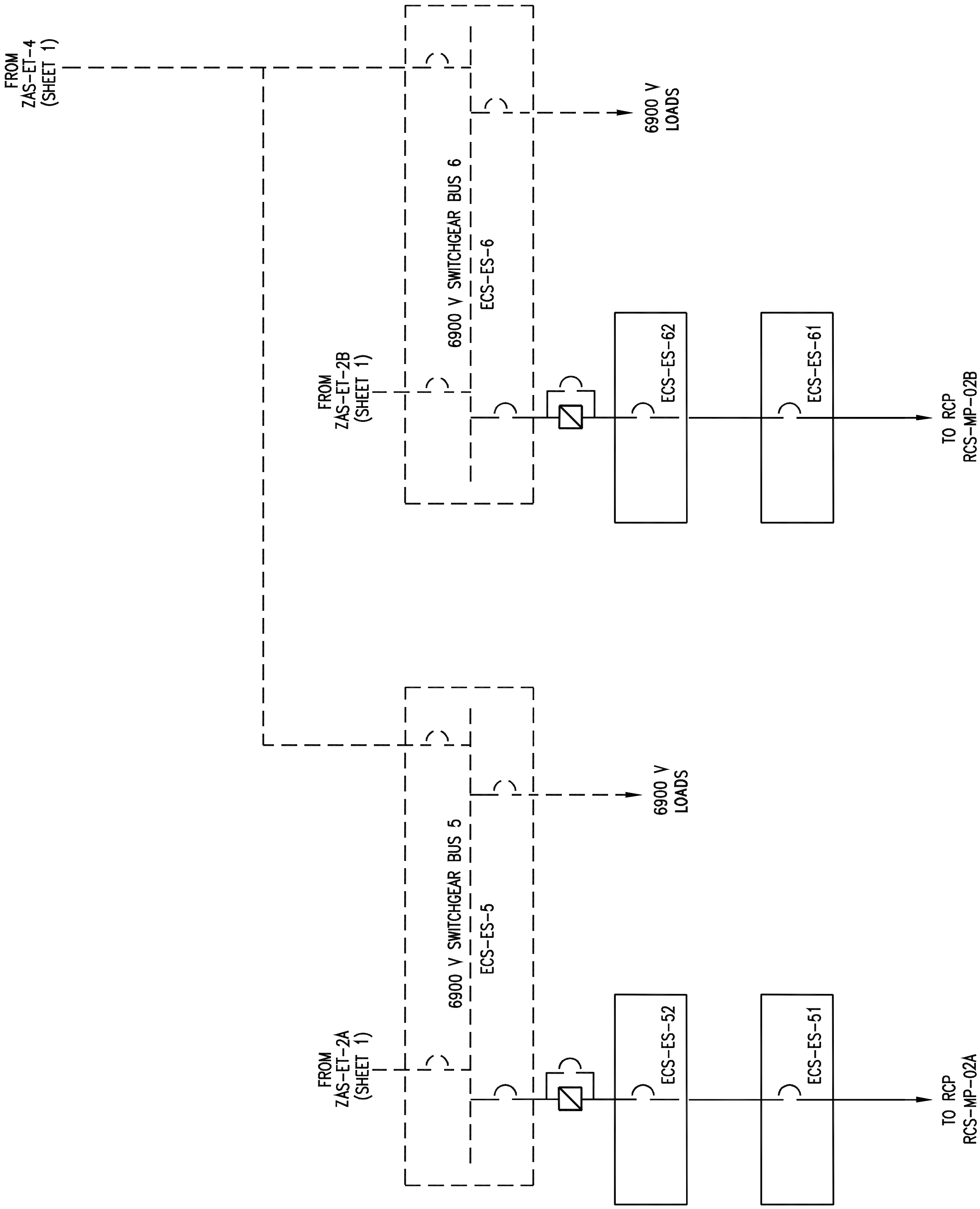


Figure 2.6.1-1 (Sheet 3 of 4)
Main ac Power System

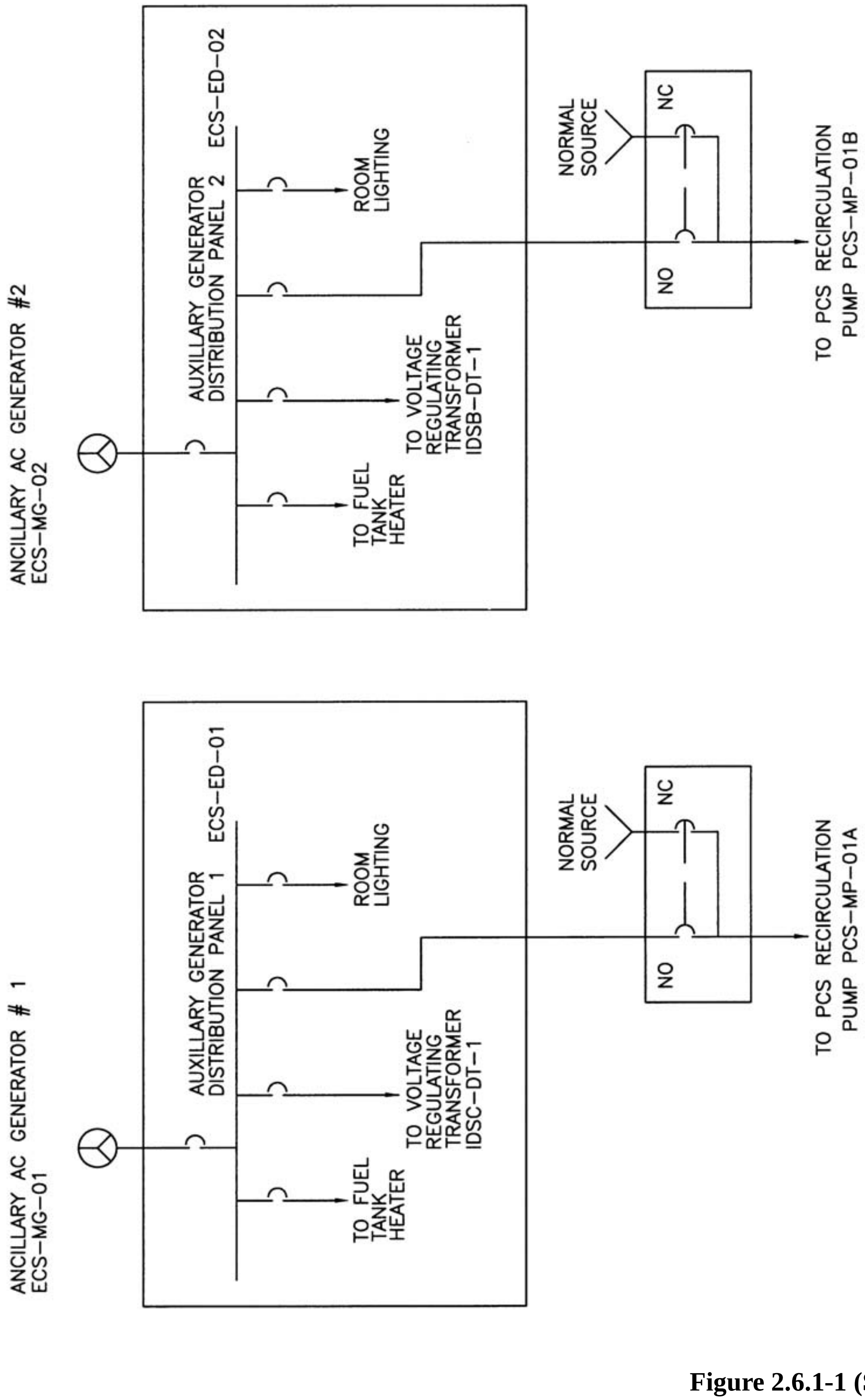


Figure 2.6.1-1 (Sheet 4 of 4)
Main ac Power System

2.6.2 Non-Class 1E dc and Uninterruptible Power Supply System

Design Description

The non-Class 1E dc and uninterruptible power supply system (EDS) provides dc and uninterruptible ac electrical power to nonsafety-related loads during normal and off-normal conditions.

The EDS is as shown in Figure 2.6.2-1 and the component locations of the EDS are as shown in Table 2.6.2-2.

1. The functional arrangement of the EDS is as described in the Design Description of this Section 2.6.2.

2. The EDS provides the following nonsafety-related functions:

   a) Each EDS load group 1, 2, and 3 battery charger supplies the corresponding dc switchboard bus load while maintaining the corresponding battery charged.

   b) Each EDS load group 1, 2, and 3 battery supplies the corresponding dc switchboard bus load for a period of 2 hours without recharging.

   c) Each EDS load group 1, 2, and 3 inverter supplies the corresponding ac load.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.6.2-1 specifies the inspections, tests, analyses, and associated acceptance criteria for the EDS.

Table 2.6.2-1
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the EDS is as described in the Design Description of this Section 2.6.2.	Inspection of the as-built system will be performed.	The as-built EDS conforms with the functional arrangement as described in the Design Description of this Section 2.6.2.
2.a) Each EDS load group 1, 2, and 3 battery charger supplies the corresponding dc switchboard bus load while maintaining the corresponding battery charged.	Testing of each as-built battery charger will be performed by applying a simulated or real load, or a combination of simulated or real loads.	Each battery charger provides an output current of at least 550 amps with an output voltage in the range 105 to 140 V.
2.b) Each EDS load group 1, 2, and 3 battery supplies the corresponding dc switchboard bus load for a period of 2 hours without recharging.	Testing of each as-built battery will be performed by applying a simulated or real load, or a combination of simulated or real loads. The test will be conducted on a battery that has been fully charged and has been connected to a battery charger maintained at 135 ± 1 V for a period of no less than 24 hours prior to the test.	The battery terminal voltage is greater than or equal to 105 V after a period of no less than 2 hours, with an equivalent load greater than 500 amps.
2.c) Each EDS load group 1, 2, and 3 inverter supplies the corresponding ac load.	Testing of each as-built inverter will be performed by applying a simulated or real load, or a combination of simulated or real loads, equivalent to a resistive load greater than 35 kW.	Each inverter provides a line-to-line output voltage of 208 ± 2% V at a frequency of 60 ± 0.5% Hz.

Table 2.6.2-2		
Component Name	**Tag No.**	**Component Location**
Load Group 1 Battery	EDS1-DB-1	Annex Building
Load Group 2 Battery	EDS2-DB-1	Annex Building
Load Group 3 Battery	EDS3-DB-1	Annex Building
Load Group 1 Battery Charger	EDS1-DC-1	Annex Building
Load Group 2 Battery Charger	EDS2-DC-1	Annex Building
Load Group 3 Battery Charger	EDS3-DC-1	Annex Building
Load Group 1 125 Vdc Switchboard	EDS1-DS-1	Annex Building
Load Group 1 125 Vdc Switchboard	EDS1-DS-11	Annex Building
Load Group 2 125 Vdc Switchboard	EDS2-DS-1	Annex Building
Load Group 2 125 Vdc Switchboard	EDS2-DS-11	Annex Building
Load Group 3 125 Vdc Switchboard	EDS3-DS-1	Annex Building
Load Group 3 125 Vdc Switchboard	EDS3-DS-11	Annex Building
Load Group 1 Inverter	EDS1-DU-1	Annex Building
Load Group 2 Inverter	EDS2-DU-1	Annex Building
Load Group 3 Inverter	EDS3-DU-1	Annex Building

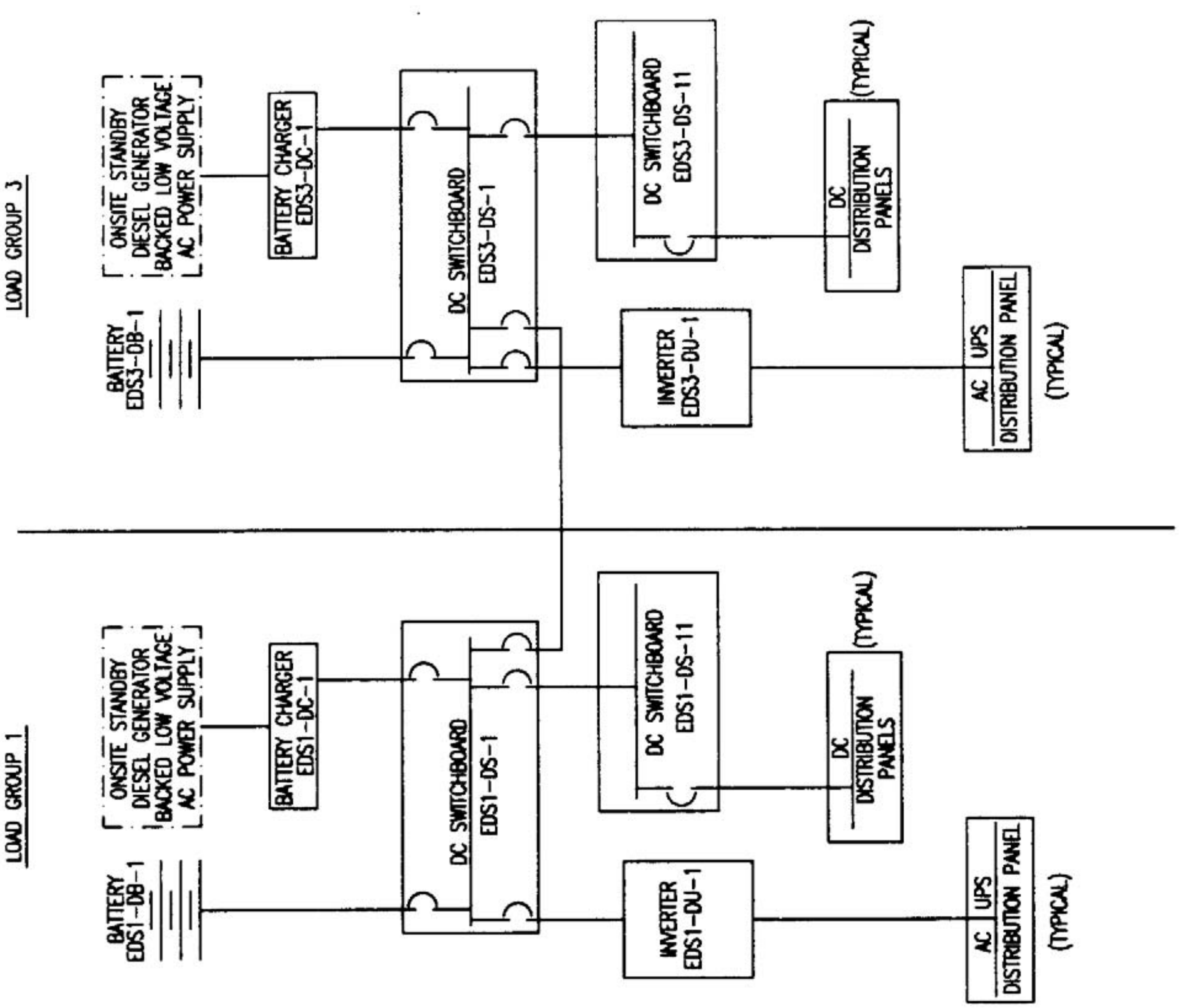


Figure 2.6.2-1 (Sheet 1 of 2)
Non-Class 1E dc and Uninterruptible Power Supply System

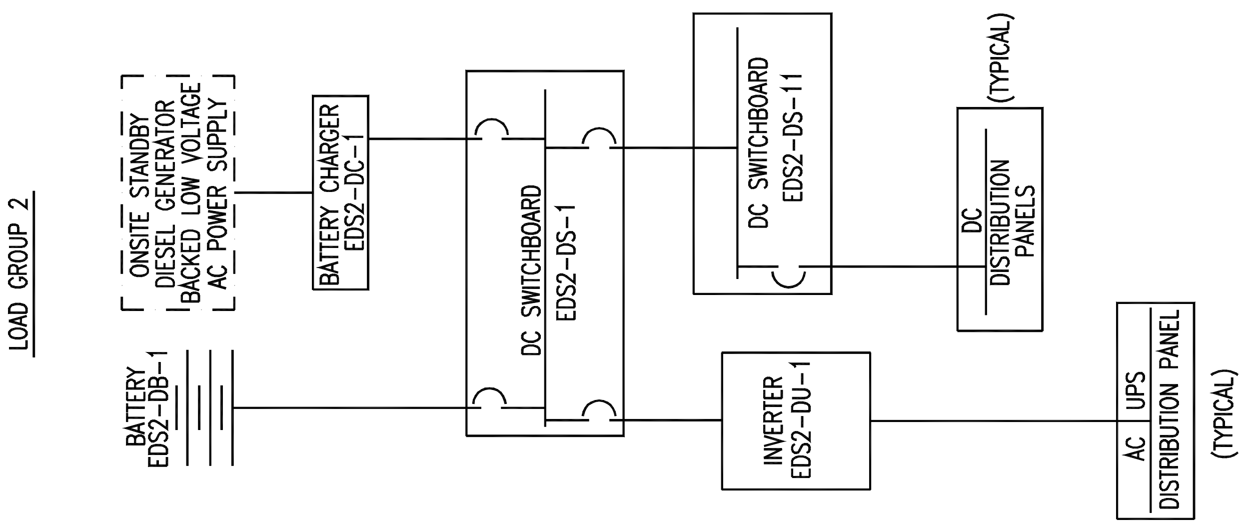


Figure 2.6.2-1 (Sheet 2 of 2)
Non-Class 1E dc and Uninterruptible Power Supply System

2.6.3 Class 1E dc and Uninterruptible Power Supply System

Design Description

The Class 1E dc and uninterruptible power supply system (IDS) provides dc and uninterruptible ac electrical power for safety-related equipment during normal and off-normal conditions.

The IDS is as shown in Figure 2.6.3-1 and the component locations of the IDS are as shown in Table 2.6.3-4.

1. The functional arrangement of the IDS is as described in the Design Description of this Section 2.6.3.

2. The seismic Category I equipment identified in Table 2.6.3-1 can withstand seismic design basis loads without loss of safety function.

3. Separation is provided between Class 1E divisions, and between Class 1E divisions and non-Class 1E cables.

4. The IDS provides the following safety-related functions:

   a) The IDS provides electrical independence between the Class 1E divisions.

   b) The IDS provides electrical isolation between the non-Class 1E ac power system and the non-Class 1E lighting in the MCR.

   c) Each IDS 24-hour battery bank supplies a dc switchboard bus load for a period of 24 hours without recharging.

   d) Each IDS 72-hour battery bank supplies a dc switchboard bus load for a period of 72 hours without recharging.

   e) The IDS spare battery bank supplies a dc load equal to or greater than the most severe switchboard bus load for the required period without recharging.

   f) Each IDS 24-hour inverter supplies its ac load.

   g) Each IDS 72-hour inverter supplies its ac load.

   h) Each IDS 24-hour battery charger provides the protection and safety monitoring system (PMS) with two loss-of-ac input voltage signals.

   i) The IDS supplies an operating voltage at the terminals of the Class 1E motor-operated valves identified in Tier 1 Material subsections 2.1.2, 2.2.1, 2.2.2, 2.2.3, 2.2.4, 2.3.2, and 2.3.6 that is greater than or equal to the minimum specified voltage.

5. The IDS provides the following nonsafety-related functions:

   a) Each IDS 24-hour battery charger supplies a dc switchboard bus load while maintaining the corresponding battery charged.

   b) Each IDS 72-hour battery charger supplies a dc switchboard bus load while maintaining the corresponding battery charged.

   c) Each IDS regulating transformer supplies an ac load when powered from the 480 V motor control center (MCC).

   d) The IDS Divisions B and C regulating transformers supply their post-72 hour ac loads when powered from an ancillary diesel generator.

6. Safety-related displays identified in Table 2.6.3-1 can be retrieved in the MCR.

7. The IDS dc battery fuses and battery charger circuit breakers, and dc distribution panels, MCCs, and their circuit breakers and fuses, are sized to supply their load requirements.

8. Circuit breakers and fuses in IDS battery, battery charger, dc distribution panel, and MCC circuits are rated to interrupt fault currents.

9. The IDS batteries, battery chargers, dc distribution panels, and MCCs are rated to withstand fault currents for the time required to clear the fault from its power source.

10. The IDS electrical distribution system cables are rated to withstand fault currents for the time required to clear the fault from its power source.

11. Displays of the parameters identified in Table 2.6.3-2 can be retrieved in the MCR.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.6.3-3 specifies the inspections, tests, analyses, and associated acceptance criteria for the IDS.

Table 2.6.3-1				
Equipment Name	Tag No.	Seismic Cat. I	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display
Division A 125 Vdc 24-Hour Battery Bank	IDSA-DB-1	Yes	Yes/No	No
Division B 125 Vdc 24-Hour Battery Bank 1	IDSB-DB-1	Yes	Yes/No	No
Division B 125 Vdc 72-Hour Battery Bank 2	IDSB-DB-2	Yes	Yes/No	No
Division C 125 Vdc 24-Hour Battery Bank 1	IDSC-DB-1	Yes	Yes/No	No
Division C 125 Vdc 72-Hour Battery Bank 2	IDSC-DB-2	Yes	Yes/No	No
Division D 125 Vdc 24-Hour Battery Bank	IDSD-DB-1	Yes	Yes/No	No
Spare 125 Vdc Battery Bank	IDSS-DB-1	Yes	Yes/No	No
Division A 24-Hour Battery Charger 1	IDSA-DC-1	Yes	Yes/No	No
Division B 24-Hour Battery Charger 1	IDSB-DC-1	Yes	Yes/No	No
Division B 72-Hour Battery Charger 2	IDSB-DC-2	Yes	Yes/No	No
Division C 24-Hour Battery Charger 1	IDSC-DC-1	Yes	Yes/No	No
Division C 72-Hour Battery Charger 2	IDSC-DC-2	Yes	Yes/No	No
Division D 24-Hour Battery Charger 1	IDSD-DC-1	Yes	Yes/No	No
Spare Battery Charger 1	IDSS-DC-1	Yes	Yes/No	No
Division A 125 Vdc Distribution Panel	IDSA-DD-1	Yes	Yes/No	No
Division B 125 Vdc Distribution Panel	IDSB-DD-1	Yes	Yes/No	No
Division C 125 Vdc Distribution Panel	IDSC-DD-1	Yes	Yes/No	No
Division D 125 Vdc Distribution Panel	IDSD-DD-1	Yes	Yes/No	No
Division A 120 Vac Distribution Panel 1	IDSA-EA-1	Yes	Yes/No	No
Division A 120 Vac Distribution Panel 2	IDSA-EA-2	Yes	Yes/No	No
Division B 120 Vac Distribution Panel 1	IDSB-EA-1	Yes	Yes/No	No
Division B 120 Vac Distribution Panel 2	IDSB-EA-2	Yes	Yes/No	No
Division B 120 Vac Distribution Panel 3	IDSB-EA-3	Yes	Yes/No	No
Division C 120 Vac Distribution Panel 1	IDSC-EA-1	Yes	Yes/No	No
Division C 120 Vac Distribution Panel 2	IDSC-EA-2	Yes	Yes/No	No
Division C 120 Vac Distribution Panel 3	IDSC-EA-3	Yes	Yes/No	No
Division D 120 Vac Distribution Panel 1	IDSD-EA-1	Yes	Yes/No	No

Table 2.6.3-1 (cont.)				
Equipment Name	**Tag No.**	**Seismic Cat. I**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**
Division D 120 Vac Distribution Panel 2	IDSD-EA-2	Yes	Yes/No	No
Division A Fuse Panel 4	IDSA-EA-4	Yes	Yes/No	No
Division B Fuse Panel 4	IDSB-EA-4	Yes	Yes/No	No
Division B Fuse Panel 5	IDSB-EA-5	Yes	Yes/No	No
Division B Fuse Panel 6	IDSB-EA-6	Yes	Yes/No	No
Division C Fuse Panel 4	IDSC-EA-4	Yes	Yes/No	No
Division C Fuse Panel 5	IDSC-EA-5	Yes	Yes/No	No
Division C Fuse Panel 6	IDSC-EA-6	Yes	Yes/No	No
Division D Fuse Panel 4	IDSD-EA-4	Yes	Yes/No	No
Division A Fused Transfer Switch Box 1	IDSA-DF-1	Yes	Yes/No	No
Division B Fused Transfer Switch Box 1	IDSB-DF-1	Yes	Yes/No	No
Division B Fused Transfer Switch Box 2	IDSB-DF-2	Yes	Yes/No	No
Division C Fused Transfer Switch Box 1	IDSC-DF-1	Yes	Yes/No	No
Division C Fused Transfer Switch Box 2	IDSC-DF-2	Yes	Yes/No	No
Division D Fused Transfer Switch Box 1	IDSD-DF-1	Yes	Yes/No	No
Spare Fused Transfer Switch Box 1	IDSS-DF-1	Yes	Yes/No	No
Division A 125 Vdc MCC	IDSA-DK-1	Yes	Yes/No	No
Division B 125 Vdc MCC	IDSB-DK-1	Yes	Yes/No	No
Division C 125 Vdc MCC	IDSC-DK-1	Yes	Yes/No	No
Division D 125 Vdc MCC	IDSD-DK-1	Yes	Yes/No	No
Division A 125 Vdc Switchboard 1	IDSA-DS-1	Yes	Yes/No	Yes (Bus Voltage)
Division B 125 Vdc Switchboard 1	IDSB-DS-1	Yes	Yes/No	Yes (Bus Voltage)
Division B 125 Vdc Switchboard 2	IDSB-DS-2	Yes	Yes/No	Yes (Bus Voltage)
Division C 125 Vdc Switchboard 1	IDSC-DS-1	Yes	Yes/No	Yes (Bus Voltage)

Table 2.6.3-1 (cont.)				
Equipment Name	**Tag No.**	**Seismic Cat. I**	**Class 1E/ Qual. for Harsh Envir.**	**Safety-Related Display**
Division C 125 Vdc Switchboard 2	IDSC-DS-2	Yes	Yes/No	Yes (Bus Voltage)
Division D 125 Vdc Switchboard 1	IDSD-DS-1	Yes	Yes/No	Yes (Bus Voltage)
Division A Regulating Transformer	IDSA-DT-1	Yes	Yes/No	No
Division B Regulating Transformer	IDSB-DT-1	Yes	Yes/No	No
Division C Regulating Transformer	IDSC-DT-1	Yes	Yes/No	No
Division D Regulating Transformer	IDSD-DT-1	Yes	Yes/No	No
Division A 24-Hour Inverter 1	IDSA-DU-1	Yes	Yes/No	No
Division B 24-Hour Inverter 1	IDSB-DU-1	Yes	Yes/No	No
Division B 72-Hour Inverter 2	IDSB-DU-2	Yes	Yes/No	No
Division C 24-Hour Inverter 1	IDSC-DU-1	Yes	Yes/No	No
Division C 72-Hour Inverter 2	IDSC-DU-2	Yes	Yes/No	No
Division D 24-Hour Inverter 1	IDSD-DU-1	Yes	Yes/No	No
Spare Termination Box 2	IDSS-DF-2	Yes	Yes/No	No
Spare Termination Box 3	IDSS-DF-3	Yes	Yes/No	No
Spare Termination Box 4	IDSS-DF-4	Yes	Yes/No	No
Spare Termination Box 5	IDSS-DF-5	Yes	Yes/No	No
Spare Termination Box 6	IDSS-DF-6	Yes	Yes/No	No

Table 2.6.3-2

Equipment	Tag No.	Display/Status Indication
Division A Battery Monitor	IDSA-DV-1	Yes (Battery Ground Detection, Battery High Discharge Rate)
Division B 24-Hour Battery Monitor	IDSB-DV-1	Yes (Battery Ground Detection, Battery High Discharge Rate)
Division B 72-Hour Battery Monitor	IDSB-DV-2	Yes (Battery Ground Detection, Battery High Discharge Rate)
Division C 24-Hour Battery Monitor	IDSC-DV-1	Yes (Battery Ground Detection, Battery High Discharge Rate)
Division C 72-Hour Battery Monitor	IDSC-DV-2	Yes (Battery Ground Detection, Battery High Discharge Rate)
Division D Battery Monitor	IDSD-DV-1	Yes (Battery Ground Detection, Battery High Discharge Rate)
Division A Fused Transfer Switch Box	IDSA-DF-1	Yes (Battery Current, Battery Disconnect Switch Position)
Division B 24-Hour Fused Transfer Switch Box	IDSB-DF-1	Yes (Battery Current, Battery Disconnect Switch Position)
Division B 72-Hour Fused Transfer Switch Box	IDSB-DF-2	Yes (Battery Current, Battery Disconnect Switch Position)
Division C 24-Hour Fused Transfer Switch Box	IDSC-DF-1	Yes (Battery Current, Battery Disconnect Switch Position)
Division C 72-Hour Fused Transfer Switch Box	IDSC-DF-2	Yes (Battery Current, Battery Disconnect Switch Position)
Division D Fused Transfer Switch Box	IDSD-DF-1	Yes (Battery Current, Battery Disconnect Switch Position)

Table 2.6.3-2 (cont.)		
Equipment	**Tag No.**	**Display/Status Indication**
Division A Battery Charger	IDSA-DC-1	Yes (Charger Output Current, Charger Trouble[1])
Division B 24-Hour Battery Charger	IDSB-DC-1	Yes (Charger Output Current, Charger Trouble[1])
Division B 72-Hour Battery Charger	IDSB-DC-2	Yes (Charger Output Current, Charger Trouble[1])
Division C 24-Hour Battery Charger	IDSC-DC-1	Yes (Charger Output Current, Charger Trouble[1])
Division C 72-Hour Battery Charger	IDSC-DC-2	Yes (Charger Output Current, Charger Trouble[1])
Division D Battery Charger	IDSD-DC-1	Yes (Charger Output Current, Charger Trouble[1])

Note: (1) Battery charger trouble includes charger dc output under/over voltage

Table 2.6.3-3
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the IDS is as described in the Design Description of this Section 2.6.3.	Inspection of the as-built system will be performed.	The as-built IDS conforms with the functional arrangement as described in the Design Description of this Section 2.6.3.
2. The seismic Category I equipment identified in Table 2.6.3-1 can withstand seismic design basis loads without loss of safety function.	i) Inspection will be performed to verify that the seismic Category I equipment identified in Table 2.6.3-1 is located on the Nuclear Island.	i) The seismic Category I equipment identified in Table 2.6.3-1 is located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis loads without loss of safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) A report exists and concludes that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.
3. Separation is provided between Class 1E divisions, and between Class 1E divisions and non-Class 1E cables.	See Tier 1 Material, Table 3.3-6, item 7.d.	See Tier 1 Material, Table 3.3-6, item 7.d.
4.a) The IDS provides electrical independence between the Class 1E divisions.	Testing will be performed on the IDS by providing a simulated test signal in each Class 1E division.	A simulated test signal exists at the Class 1E equipment identified in Table 2.6.3-1 when the assigned Class 1E division is provided the test signal.
4.b) The IDS provides electrical isolation between the non-Class 1E ac power system and the non-Class 1E lighting in the MCR.	Type tests, analyses, or a combination of type tests and analyses of the isolation devices will be performed.	A report exists and concludes that the battery chargers, regulating transformers, and isolation fuses prevent credible faults from propagating into the IDS.

Table 2.6.3-3 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4.c) Each IDS 24-hour battery bank supplies a dc switchboard bus load for a period of 24 hours without recharging.	Testing of each 24-hour as-built battery bank will be performed by applying a simulated or real load, or a combination of simulated or real loads which envelope the battery bank design duty cycle. The test will be conducted on a battery bank that has been fully charged and has been connected to a battery charger maintained at 135 ± 1 V for a period of no less than 24 hours prior to the test.	The battery terminal voltage is greater than or equal to 105 V after a period of no less than 24 hours with an equivalent load that equals or exceeds the battery bank design duty cycle capacity.
4.d) Each IDS 72-hour battery bank supplies a dc switchboard bus load for a period of 72 hours without recharging.	Testing of each 72-hour as-built battery bank will be performed by applying a simulated or real load, or a combination of simulated or real loads which envelope the battery bank design duty cycle. The test will be conducted on a battery bank that has been fully charged and has been connected to a battery charger maintained at 135 ± 1 V for a period of no less than 24 hours prior to the test.	The battery terminal voltage is greater than or equal to 105 V after a period of no less than 72 hours with an equivalent load that equals or exceeds the battery bank design duty cycle capacity.
4.e) The IDS spare battery bank supplies a dc load equal to or greater than the most severe switchboard bus load for the required period without recharging.	Testing of the as-built spare battery bank will be performed by applying a simulated or real load, or a combination of simulated or real loads which envelope the most severe of the division batteries design duty cycle. The test will be conducted on a battery bank that has been fully charged and has been connected to a battery charger maintained at 135 ± 1 V for a period of no less than 24 hours prior to the test.	The battery terminal voltage is greater than or equal to 105 V after a period with a load and duration that equals or exceeds the most severe battery bank design duty cycle capacity.

Table 2.6.3-3 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4.f) Each IDS 24-hour inverter supplies its ac load.	Testing of each 24-hour as-built inverter will be performed by applying a simulated or real load, or a combination of simulated or real loads, equivalent to a resistive load greater than 12 kW. The inverter input voltage will be no more than 105 Vdc during the test.	Each 24-hour inverter supplies a line-to-line output voltage of 208 ± 2% V at a frequency of 60 ± 0.5% Hz.
4.g) Each IDS 72-hour inverter supplies its ac load.	Testing of each 72-hour as-built inverter will be performed by applying a simulated or real load, or a combination of simulated or real loads, equivalent to a resistive load greater than 7 kW. The inverter input voltage will be no more than 105 Vdc during the test.	Each 72-hour inverter supplies a line-to-line output voltage of 208 ± 2% V at a frequency of 60 ± 0.5% Hz.
4.h) Each IDS 24-hour battery charger provides the PMS with two loss-of-ac input voltage signals.	Testing will be performed by simulating a loss of input voltage to each 24-hour battery charger.	Two PMS input signals exist from each 24-hour battery charger indicating loss of ac input voltage when the loss-of-input voltage condition is simulated.
4.i) The IDS supplies an operating voltage at the terminals of the Class 1E motor operated valves identified in Tier 1 Material subsections 2.1.2, 2.2.1, 2.2.2, 2.2.3, 2.2.4, 2.3.2, and 2.3.6 that is greater than or equal to the minimum specified voltage.	Testing will be performed by stroking each specified motor-operated valve and measuring the terminal voltage at the motor starter input terminals with the motor operating. The battery terminal voltage will be no more than 105 Vdc during the test.	The motor starter input terminal voltage is greater than or equal 100 Vdc with the motor operating.
5.a) Each IDS 24-hour battery charger supplies a dc switchboard bus load while maintaining the corresponding battery charged.	Testing of each as-built 24-hour battery charger will be performed by applying a simulated or real load, or a combination of simulated or real loads.	Each 24-hour battery charger provides an output current of at least 300 A with an output voltage in the range 105 to 140 V.
5.b) Each IDS 72-hour battery charger supplies a dc switchboard bus load while maintaining the corresponding battery charged.	Testing of each 72-hour as-built battery charger will be performed by applying a simulated or real load, or a combination of simulated or real loads.	Each 72-hour battery charger provides an output current of at least 250 A with an output voltage in the range 105 to 140 V.

Table 2.6.3-3 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5.c) Each IDS regulating transformer supplies an ac load when powered from the 480 V MCC.	Testing of each as-built regulating transformer will be performed by applying a simulated or real load, or a combination of simulated or real loads, equivalent to a resistive load greater than 30 kW when powered from the 480 V MCC.	Each regulating transformer supplies a line-to-line output voltage of 208 ± 2% V.
5.d) The IDS Divisions B and C regulating transformers supply their post-72-hour ac loads when powered from an ancillary diesel generator.	Inspection of the as-built system will be performed.	i) Ancillary diesel generator 1 is electrically connected to regulating transformer IDSC-DT-1 ii) Ancillary diesel generator 2 is electrically connected to regulating transformer IDSB-DT-1.
6. Safety-related displays identified in Table 2.6.3-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the safety-related displays in the MCR.	Safety-related displays identified in Table 2.6.3-1 can be retrieved in the MCR.
7. The IDS dc battery fuses and battery charger circuit breakers, and dc distribution panels, MCCs, and their circuit breakers and fuses, are sized to supply their load requirements.	Analyses for the as-built IDS dc electrical distribution system to determine the capacities of the battery fuses and battery charger circuit breakers, and dc distribution panels, MCCs, and their circuit breakers and fuses, will be performed.	Analyses for the as-built IDS dc electrical distribution system exist and conclude that the capacities of as-built IDS battery fuses and battery charger circuit breakers, and dc distribution panels, MCCs, and their circuit breakers and fuses, as determined by their nameplate ratings, exceed their analyzed load requirements.
8. Circuit breakers and fuses in IDS battery, battery charger, dc distribution panel, and MCC circuits are rated to interrupt fault currents.	Analyses for the as-built IDS dc electrical distribution system to determine fault currents will be performed.	Analyses for the as-built IDS dc electrical distribution system exist and conclude that the analyzed fault currents do not exceed the interrupt capacity of circuit breakers and fuses in the battery, battery charger, dc distribution panel, and MCC circuits, as determined by their nameplate ratings.

Table 2.6.3-3 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9. The IDS batteries, battery chargers, dc distribution panels, and MCCs are rated to withstand fault currents for the time required to clear the fault from its power source.	Analyses for the as-built IDS dc electrical distribution system to determine fault currents will be performed.	Analyses for the as-built IDS dc electrical distribution system exist and conclude that the fault current capacities of as-built IDS batteries, battery chargers, dc distribution panels, and MCCs, as determined by manufacturer's ratings, exceed their analyzed fault currents for the time required to clear the fault from its power source as determined by the circuit interrupting device coordination analyses.
10. The IDS electrical distribution system cables are rated to withstand fault currents for the time required to clear the fault from its power source.	Analyses for the as-built IDS dc electrical distribution system to determine fault currents will be performed.	Analyses for the as-built IDS dc electrical distribution system exist and conclude that the IDS dc electrical distribution system cables will withstand the analyzed fault currents, as determined by manufacturer's ratings, for the time required to clear the fault from its power source as determined by the circuit interrupting device coordination analyses.
11. Displays of the parameters identified in Table 2.6.3-2 can be retrieved in the MCR.	Inspection will be performed for retrievability of the displays identified in Table 2.6.3-2 in the MCR.	Displays identified in Table 2.6.3-2 can be retrieved in the MCR.

Table 2.6.3-4		
Component Name	**Tag No.**	**Component Location**
Division A 125 Vdc 24-Hour Battery Bank	IDSA-DB-1	Auxiliary Building
Division B 125 Vdc 24-Hour Battery Bank 1	IDSB-DB-1	Auxiliary Building
Division B 125 Vdc 72-Hour Battery Bank 2	IDSB-DB-2	Auxiliary Building
Division C 125 Vdc 24-Hour Battery Bank 1	IDSC-DB-1	Auxiliary Building
Division C 125 Vdc 72-Hour Battery Bank 2	IDSC-DB-2	Auxiliary Building
Division D 125 Vdc 24-Hour Battery Bank	IDSD-DB-1	Auxiliary Building
Spare 125 Vdc Battery Bank	IDSS-DB-1	Auxiliary Building
Division A 24-Hour Battery Charger 1	IDSA-DC-1	Auxiliary Building
Division B 24-Hour Battery Charger 1	IDSB-DC-1	Auxiliary Building
Division B 72-Hour Battery Charger 2	IDSB-DC-2	Auxiliary Building
Division C 24-Hour Battery Charger 1	IDSC-DC-1	Auxiliary Building
Division C 72-Hour Battery Charger 2	IDSC-DC-2	Auxiliary Building
Division D 24-Hour Battery Charger 1	IDSD-DC-1	Auxiliary Building
Spare Battery Charger 1	IDSS-DD-1	Auxiliary Building
Division A 125 Vdc Distribution Panel	IDSA-DD-1	Auxiliary Building
Division B 125 Vdc Distribution Panel	IDSB-DD-1	Auxiliary Building
Division C 125 Vdc Distribution Panel	IDSC-DD-2	Auxiliary Building
Division D 125 Vdc Distribution Panel	IDSD-DD-1	Auxiliary Building
Division A 120 Vac Distribution Panel 1	IDSA-EA-1	Auxiliary Building
Division A 120 Vac Distribution Panel 2	IDSA-EA-2	Auxiliary Building
Division B 120 Vac Distribution Panel 1	IDSB-EA-1	Auxiliary Building
Division B 120 Vac Distribution Panel 2	IDSB-EA-2	Auxiliary Building
Division B 120 Vac Distribution Panel 3	IDSB-EA-3	Auxiliary Building
Division C 120 Vac Distribution Panel 1	IDSC-EA-1	Auxiliary Building
Division C 120 Vac Distribution Panel 2	IDSC-EA-2	Auxiliary Building
Division C 120 Vac Distribution Panel 3	IDSC-EA-3	Auxiliary Building
Division D 120 Vac Distribution Panel 1	IDSD-EA-1	Auxiliary Building
Division D 120 Vac Distribution Panel 2	IDSD-EA-2	Auxiliary Building

Table 2.6.3-4 (cont.)		
Component Name	**Tag No.**	**Component Location**
Division A Fuse Panel 4	IDSA-EA-4	Auxiliary Building
Division B Fuse Panel 4	IDSB-EA-4	Auxiliary Building
Division B Fuse Panel 5	IDSB-EA-5	Auxiliary Building
Division B Fuse Panel 6	IDSB-EA-6	Auxiliary Building
Division C Fuse Panel 4	IDSC-EA-4	Auxiliary Building
Division C Fuse Panel 5	IDSC-EA-5	Auxiliary Building
Division C Fuse Panel 6	IDSC-EA-6	Auxiliary Building
Division D Fuse Panel 4	IDSD-EA-4	Auxiliary Building
Division A Fused Transfer Switch Box 1	IDSA-DF-1	Auxiliary Building
Division B Fused Transfer Switch Box 1	IDSB-DF-1	Auxiliary Building
Division B Fused Transfer Switch Box 2	IDSB-DF-2	Auxiliary Building
Division C Fused Transfer Switch Box 1	IDSC-DF-1	Auxiliary Building
Division C Fused Transfer Switch Box 2	IDSC-DF-2	Auxiliary Building
Division D Fused Transfer Switch Box 1	IDSD-DF-1	Auxiliary Building
Spare Fused Transfer Switch Box 1	IDSS-DF-1	Auxiliary Building
Division A 125 Vdc MCC	IDSA-DK-1	Auxiliary Building
Division B 125 Vdc MCC	IDSB-DK-1	Auxiliary Building
Division C 125 Vdc MCC	IDSC-DK-1	Auxiliary Building
Division D 125 Vdc MCC	IDSD-DK-1	Auxiliary Building
Division A 125 Vdc Switchboard 1	IDSA-DS-1	Auxiliary Building
Division B 125 Vdc Switchboard 1	IDSB-DS-1	Auxiliary Building
Division B 125 Vdc Switchboard 2	IDSB-DS-2	Auxiliary Building
Division C 125 Vdc Switchboard 1	IDSC-DS-1	Auxiliary Building
Division C 125 Vdc Switchboard 2	IDSC-DS-2	Auxiliary Building
Division D 125 Vdc Switchboard 1	IDSD-DS-1	Auxiliary Building
Division A Regulating Transformer	IDSA-DT-1	Auxiliary Building
Division B Regulating Transformer	IDSB-DT-1	Auxiliary Building
Division C Regulating Transformer	IDSC-DT-1	Auxiliary Building

Table 2.6.3-4 (cont.)		
Component Name	**Tag No.**	**Component Location**
Division D Regulating Transformer	IDSD-DT-1	Auxiliary Building
Division A 24-Hour Inverter 1	IDSA-DU-1	Auxiliary Building
Division B 24-Hour Inverter 1	IDSB-DU-1	Auxiliary Building
Division B 72-Hour Inverter 2	IDSB-DU-2	Auxiliary Building
Division C 24-Hour Inverter 1	IDSC-DU-1	Auxiliary Building
Division C 72-Hour Inverter 2	IDSC-DU-2	Auxiliary Building
Division D 24-Hour Inverter 1	IDSD-DU-1	Auxiliary Building
Spare Termination Box 2	IDSS-DF-2	Auxiliary Building
Spare Termination Box 3	IDSS-DF-3	Auxiliary Building
Spare Termination Box 4	IDSS-DF-4	Auxiliary Building
Spare Termination Box 5	IDSS-DF-5	Auxiliary Building
Spare Termination Box 6	IDSS-DF-6	Auxiliary Building

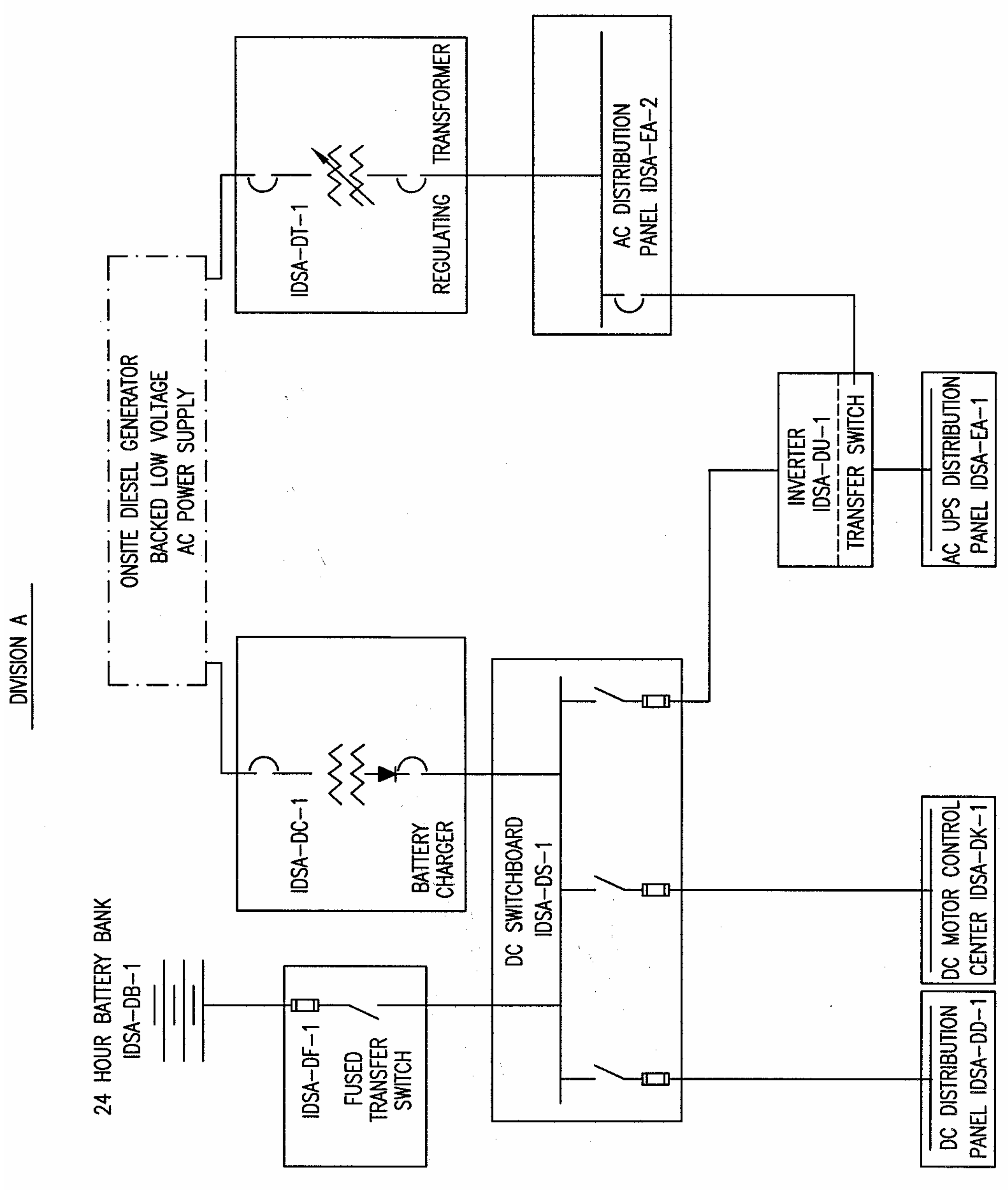


Figure 2.6.3-1 (Sheet 1 of 4)
Class 1E dc and Uninterruptible Power Supply System (Division A)

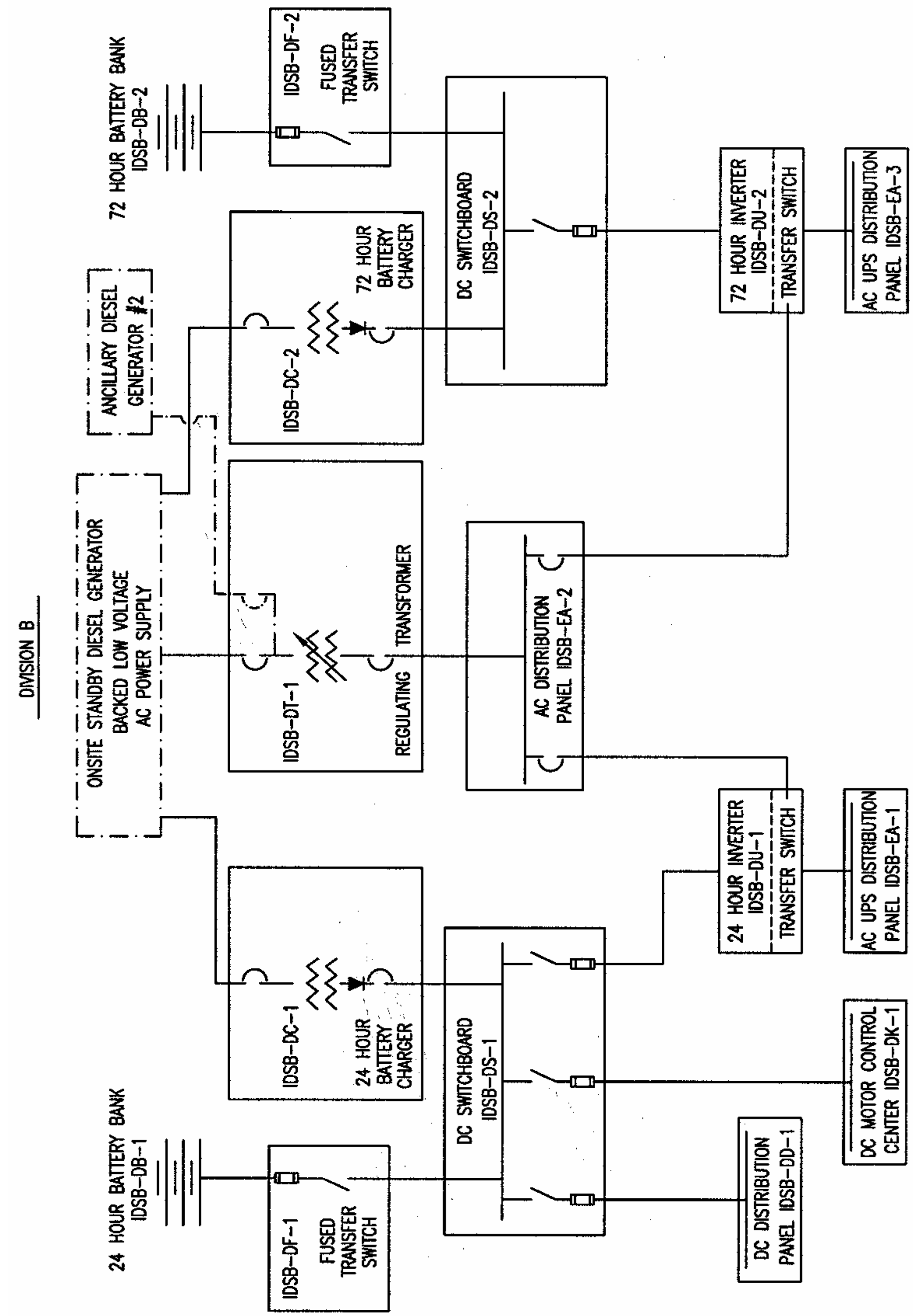


Figure 2.6.3-1 (Sheet 2 of 4)
Class 1E dc and Uninterruptible Power Supply System (Division B)

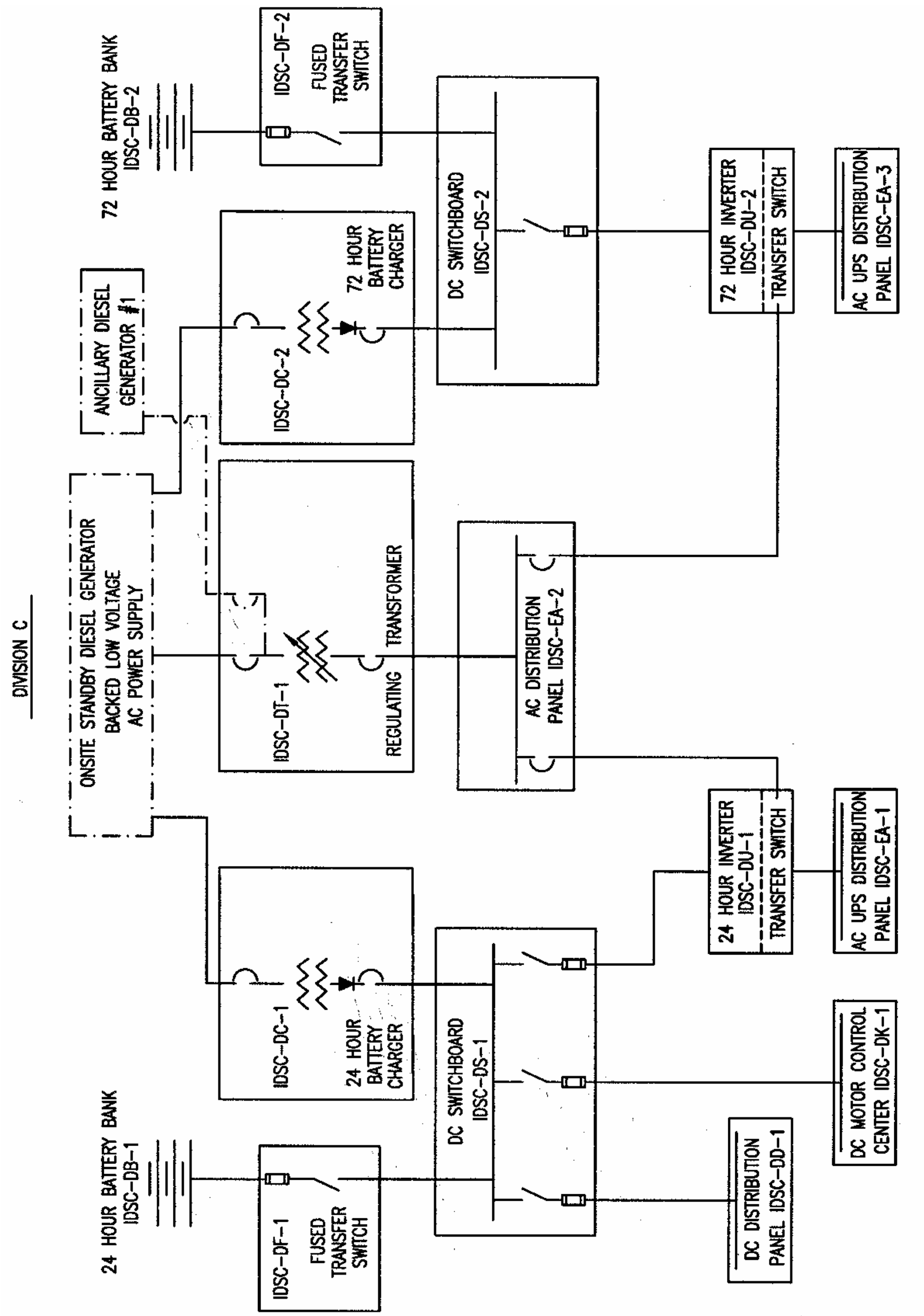


Figure 2.6.3-1 (Sheet 3 of 4)
Class 1E dc and Uninterruptible Power Supply System (Division C)

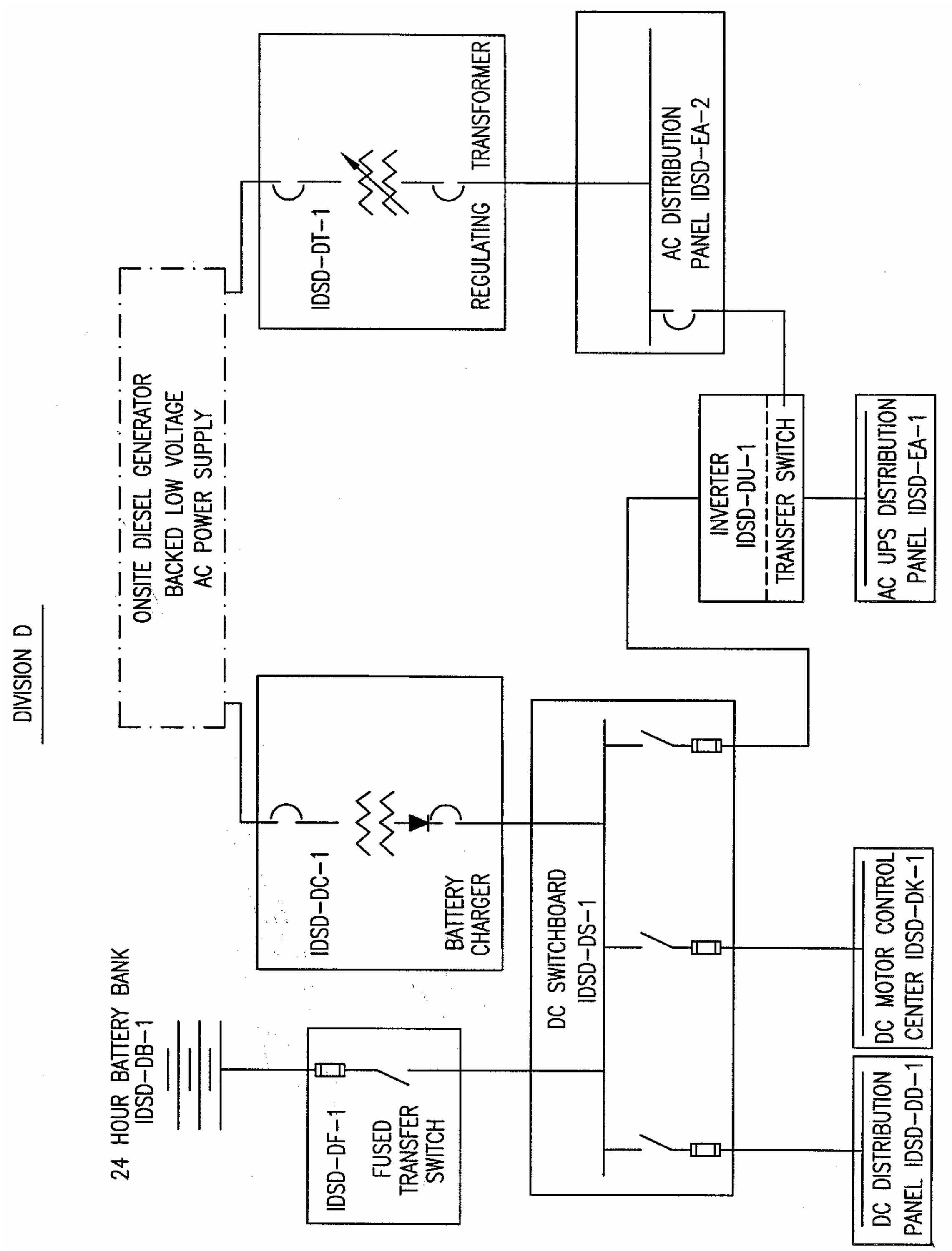


Figure 2.6.3-1 (Sheet 4 of 4)
Class 1E dc and Uninterruptible Power Supply System (Division D)

2.6.4 Onsite Standby Power System

Design Description

The onsite standby power system (ZOS) provides backup ac electrical power for nonsafety-related loads during normal and off-normal conditions.

The ZOS has two standby diesel generator units and the component locations of the ZOS are as shown in Table 2.6.4-2. The centerline of the diesel engine exhaust gas discharge is located more than twenty (20) feet higher than that of the combustion air intake.

1. The functional arrangement of the ZOS is as described in the Design Description of this Section 2.6.4.

2. The ZOS provides the following nonsafety-related functions:

   a) On loss of power to a 6900 volt diesel-backed bus, the associated diesel generator automatically starts and produces ac power at rated voltage and frequency. The source circuit breakers and bus load circuit breakers are opened, and the generator is connected to the bus.

   b) Each diesel generator unit is sized to supply power to the selected nonsafety-related electrical components.

   c) Automatic-sequence loads are sequentially loaded on the associated buses.

3. Displays of diesel generator status (running/not running) and electrical output power (watts) can be retrieved in the main control room (MCR).

4. Controls exist in the MCR to start and stop each diesel generator.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.6.4-1 specifies the inspections, tests, analyses, and associated acceptance criteria for the ZOS.

Table 2.6.4-1
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the ZOS is as described in the Design Description of this Section 2.6.4.	Inspection of the as-built system will be performed.	The as-built ZOS conforms with the functional arrangement as described in the Design Description of this Section 2.6.4.
2.a) On loss of power to a 6900 volt diesel-backed bus, the associated diesel generator automatically starts and produces ac power at rated voltage and frequency. The source circuit breakers and bus load circuit breakers are opened, and the generator is connected to the bus.	Tests on the as-built ZOS system will be conducted by providing a simulated loss-of-voltage signal. The starting air supply receiver will not be replenished during the test.	Each as-built diesel generator automatically starts on receiving a simulated loss-of-voltage signal and attains a voltage of 6900 ± 10% V and frequency 60 ± 5% Hz after the start signal is initiated and opens ac power system breakers on the associated 6900 V bus.
2.b) Each diesel generator unit is sized to supply power to the selected nonsafety-related electrical components.	Each diesel generator will be operated with a load of 4000 kW or greater and a power factor between 0.9 and 1.0 for a time period required to reach engine temperature equilibrium plus 2.5 hours.	Each diesel generator provides power to the load with a generator terminal voltage of 6900 ± 10% V and a frequency of 60 ± 5% Hz.
2.c) Automatic-sequence loads are sequentially loaded on the associated buses.	An actual or simulated signal is initiated to start the load sequencer operation. Output signals will be monitored to determine the operability of the load sequencer. Time measurements are taken to determine the load stepping intervals.	The load sequencer initiates a closure signal within ±5 seconds of the set intervals to connect the loads.
3. Displays of diesel generator status (running/not running) and electrical output power (watts) can be retrieved in the MCR.	Inspection will be performed for retrievability of the displays in the MCR.	Displays of diesel generator status and electrical output power can be retrieved in the MCR.
4. Controls exist in the MCR to start and stop each diesel generator.	A test will be performed to verify that controls in the MCR can start and stop each diesel generator.	Controls in the MCR operate to start and stop each diesel generator.

Table 2.6.4-2		
Component Name	**Tag No.**	**Component Location**
Onsite Diesel Generator A Package	ZOS-MS-05A	Diesel Generator Building
Onsite Diesel Generator B Package	ZOS-MS-05B	Diesel Generator Building

2.6.5 Lighting System

Design Description

The lighting system (ELS) provides the normal and emergency lighting in the main control room (MCR) and at the remote shutdown workstation (RSW).

1. The functional arrangement of the ELS is as described in the Design Description of this Section 2.6.5.

2. The ELS has six groups of emergency lighting fixtures located in the MCR and at the RSW. Each group is powered by one of the Class 1E inverters. The ELS has four groups of panel lighting fixtures located on or near safety panels in the MCR. Each group is powered by one of the Class 1E inverters in Divisions B and C (one 24-hour and one 72-hour inverter in each Division).

3. The lighting fixtures located in the MCR utilize seismic supports.

4. The panel lighting circuits are classified as associated and treated as Class 1E. These lighting circuits are routed with the Divisions B and C Class 1E circuits. Separation is provided between ELS associated divisions and between associated divisions and non-Class 1E cable.

5. The normal lighting can provide 50 foot candles at the safety panel and at the workstations in the MCR and at the RSW.

6. The emergency lighting can provide 10 foot candles at the safety panel and at the workstations in the MCR and at the RSW.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.6.5-1 specifies the inspections, tests, analyses, and associated acceptance criteria for the ELS.

Table 2.6.5-1
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the ELS is as described in the Design Description of this Section 2.6.5.	Inspection of the as-built system will be performed.	The as-built ELS conforms with the functional arrangement as described in the Design Description of this Section 2.6.5.
2. The ELS has six groups of emergency lighting fixtures located in the MCR and at the RSW. Each group is powered by one of the Class 1E inverters. The ELS has four groups of panel lighting fixtures located on or near safety panels in the MCR. Each group is powered by one of the Class 1E inverters in Divisions B and C (one 24-hour and one 72-hour inverter in each Division).	i) Inspection of the as-built system will be performed. ii) Testing of the as-built system will be performed using one Class 1E inverter at a time.	i) The as-built ELS has six groups of emergency lighting fixtures located in the MCR and at the RSW. The ELS has four groups of panel lighting fixtures located on or near safety panels in the MCR. ii) Each of the six as-built emergency lighting groups is supplied power from its respective Class 1E inverter and each of the four as-built panel lighting groups is supplied power from its respective Class 1E inverter.
3. The lighting fixtures located in the MCR utilize seismic supports.	i) Inspection will be performed to verify that the lighting fixtures located in the MCR are located on the Nuclear Island. ii) Analysis of seismic supports will be performed.	i) The lighting fixtures located in the MCR are located on the Nuclear Island. ii) A report exists and concludes that the seismic supports can withstand seismic design basis loads.
4. The panel lighting circuits are classified as associated and treated as Class 1E. These lighting circuits are routed with the Divisions B and C Class 1E circuits. Separation is provided between ELS associated divisions and between associated divisions and non-Class 1E cable.	See Tier 1 Material, Table 3.3-6, item 7.d.	See Tier 1 Material, Table 3.3-6, item 7.d.

Table 2.6.5-1 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. The normal lighting can provide 50 foot candles at the safety panel and at the workstations in the MCR and at the RSW.	i) Testing of the as-built normal lighting in the MCR will be performed.	i) When adjusted for maximum illumination and powered by the main ac power system, the normal lighting in the MCR provides at least 50 foot candles at the safety panel and at the workstations.
	ii) Testing of the as-built normal lighting at the RSW will be performed.	ii) When adjusted for maximum illumination and powered by the main ac power system, the normal lighting in the MCR provides at least 50 foot candles at the safety panel and at the workstations.
6. The emergency lighting can provide 10 foot candles at the safety panel and at the workstations in the MCR and at the RSW.	i) Testing of the as-built emergency lighting in the MCR will be performed.	i) When adjusted for maximum illumination and powered by the six Class 1E inverters, the emergency lighting in the MCR provides at least 10 foot candles at the safety panel and at the workstations.
	ii) Testing of the as-built emergency lighting at the RSW will be performed.	ii) When adjusted for maximum illumination and powered by the six Class 1E inverters, the emergency lighting provides at least 10 foot candles at the RSW.

2.6.6 Grounding and Lightning Protection System

Design Description

The grounding and lightning protection system (EGS) provides electrical grounding for instrumentation grounding, equipment grounding, and lightning protection during normal and off-normal conditions.

1. The EGS provides an electrical grounding system for: (1) instrument/computer grounding; (2) electrical system grounding of the neutral points of the main generator, main step-up transformers, auxiliary transformers, load center transformers, and onsite standby diesel generators; and (3) equipment grounding of equipment enclosures, metal structures, metallic tanks, ground bus of switchgear assemblies, load centers, motor control centers, and control cabinets. Lightning protection is provided for exposed structures and buildings housing safety-related and fire protection equipment. Each grounding system and lightning protection system is grounded to the station grounding grid.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.6.6-1 specifies the inspections, tests, analyses, and associated acceptance criteria for the EGS.

Table 2.6.6-1
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The EGS provides an electrical grounding system for: (1) instrument/computer grounding; (2) electrical system grounding of the neutral points of the main generator, main step-up transformers, auxiliary transformers, load center transformers, auxiliary and onsite standby diesel generators; and (3) equipment grounding of equipment enclosures, metal structures, metallic tanks, ground bus of switchgear assemblies, load centers, motor control centers, and control cabinets. Lightning protection is provided for exposed structures and buildings housing safety-related and fire protection equipment. Each grounding system and lighting protection system is grounded to the station grounding grid.	i) An inspection for the instrument/computer grounding system connection to the station grounding grid will be performed. ii) An inspection for the electrical system grounding connection to the station grounding grid will be performed. iii) An inspection for the equipment grounding system connection to the station grounding grid will be performed. iv) An inspection for the lightning protection system connection to the station grounding grid will be performed.	i) A connection exists between the instrument/computer grounding system and the station grounding grid. ii) A connection exists between the electrical system grounding and the station grounding grid. iii) A connection exists between the equipment grounding system and the station grounding grid. iv) A connection exists between the lighting protection system and the station grounding grid.

2.6.7 Special Process Heat Tracing System

No entry for this system.

2.6.8 Cathodic Protection System

No entry.

2.6.9 Plant Security System

No entry.

2.6.10 Main Generation System

No entry. Covered in Section 2.6.1, Main ac Power System.

2.6.11 Excitation and Voltage Regulation System

No entry for this system.

2.7.1 Nuclear Island Nonradioactive Ventilation System

Design Description

The nuclear island nonradioactive ventilation system (VBS) serves the main control room (MCR), technical support center (TSC), Class 1E dc equipment rooms, Class 1E instrumentation and control (I&C) rooms, Class 1E electrical penetration rooms, Class 1E battery rooms, remote shutdown room (RSR), reactor coolant pump trip switchgear rooms, adjacent corridors, and passive containment cooling system (PCS) valve room during normal plant operation. The VBS consists of the following independent subsystems: the main control room/technical support center HVAC subsystem, the class 1E electrical room HVAC subsystem, and the passive containment cooling system valve room heating and ventilation subsystem. The VBS provides heating, ventilation, and cooling to the areas served when ac power is available. The system provides breathable air to the control room and maintains the main control room and technical support center areas at a slightly positive pressure with respect to the adjacent rooms and outside environment during normal operations. The VBS monitors the main control room supply air for radioactive particulate and iodine concentrations and provides filtration of main control room/technical support center air during conditions of abnormal (high) airborne radioactivity. In addition, the VBS isolates the HVAC penetrations in the main control room boundary on "high-high" particulate or iodine radioactivity in the main control room supply air duct or on a loss of ac power for more than 10 minutes. This action supports operation of the main control room emergency habitability system (VES).

The VBS is as shown in Figure 2.7.1-1 and the component locations of the VBS are as shown in Table 2.7.1-5.

1. The functional arrangement of the VBS is as described in the Design Description of this subsection 2.7.1.

2. a) The components identified in Table 2.7.1-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.

   b) The piping identified in Table 2.7.1-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.

3. a) Pressure boundary welds in components identified in Table 2.7.1-1 as ASME Code Section III meet ASME Code Section III requirements.

   b) Pressure boundary welds in piping identified in Table 2.7.1-2 as ASME Code Section III meet ASME Code Section III requirements.

4. a) The components identified in Table 2.7.1-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.

   b) The piping identified in Table 2.7.1-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.

5. The seismic Category I equipment identified in Table 2.7.1-1 can withstand seismic design basis loads without loss of safety function.

6. a) The Class 1E components identified in Table 2.7.1-1 are powered from their respective Class 1E division.

   b) Separation is provided between VBS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.

7. The VBS provides the safety-related function to isolate the pipes that penetrate the MCR pressure boundary.

8. The VBS provides the following nonsafety-related functions:

   a) The VBS provides cooling to the MCR, TSC, RSR, and Class 1E electrical rooms.

   b) The VBS provides ventilation cooling to the Class 1E battery rooms.

   c) The VBS maintains MCR and TSC habitability when radioactivity is detected.

   d) The VBS provides ventilation cooling via the ancillary equipment in Table 2.7.1-3 to the MCR and the division B&C Class 1E I&C rooms.

9. Safety-related displays identified in Table 2.7.1-1 can be retrieved in the MCR.

10. a) Controls exist in the MCR to cause the remotely operated valves identified in Table 2.7.1-1 to perform their active functions.

    b) The valves identified in Table 2.7.1-1 as having protection and safety monitoring system (PMS) control perform their active safety function after receiving a signal from the PMS.

11. After loss of motive power, the valves identified in Table 2.7.1-1 assume the indicated loss of motive power position.

12. Controls exist in the MCR to cause the components identified in Table 2.7.1-3 to perform the listed function.

13. Displays of the parameters identified in Table 2.7.1-3 can be retrieved in the MCR.

14. The background noise level in the MCR and RSR does not exceed 65 dB(A) when the VBS is operating.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.7.1-4 specifies the inspections, tests, analyses, and associated acceptance criteria for the VBS.

Table 2.7.1-1

Equipment Name	Tag No.	ASME Code Section III	Seismic Cat. I	Remotely Operated Valve	Class 1E/ Qual. for Harsh Envir.	Safety-Related Display	Control PMS/DAS[1]	Active Function	Loss of Motive Power Position
MCR Supply Air Isolation Valve	VBS-PL-V186	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Closed	Closed
MCR Supply Air Isolation Valve	VBS-PL-V187	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Closed	Closed
MCR Return Air Isolation Valve	VBS-PL-V188	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Closed	Closed
MCR Return Air Isolation Valve	VBS-PL-V189	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Closed	Closed
MCR Exhaust Air Isolation Valve	VBS-PL-V190	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Closed	Closed
MCR Exhaust Air Isolation Valve	VBS-PL-V191	Yes	Yes	Yes	Yes/No	Yes (Valve Position)	Yes/No	Transfer Closed	Closed

1. DAS = diverse actuation system

Table 2.7.1-2				
Line Name	**Line Number**	**ASME Code Section III**	**Leak Before Break**	**Functional Capability Required**
Main Control Room Supply	VBS-L311	Yes	No	No
Main Control Room Exhaust	VBS-L312	Yes	No	No
Main Control Room Toilet Exhaust	VBS-L313	Yes	No	No

Table 2.7.1-3			
Equipment	**Tag No.**	**Display**	**Control Function**
Supplemental Air Filtration Unit Fan A	VBS-MA-03A	Yes (Run Status)	Start
Supplemental Air Filtration Unit Fan B	VBS-MA-03B	Yes (Run Status)	Start
MCR/TSC Supply Air Handling Units (AHU) A Fans	VBS-MA-01A VBS-MA-02A	Yes (Run Status)	Start
MCR/TSC Supply AHU B Fans	VBS-MA-01B VBS-MA-02B	Yes (Run Status)	Start
Division "A" and "C" Class 1E Electrical Room AHU A Fans	VBS-MA-05A VBS-MA-06A	Yes (Run Status)	Start
Division "A" and "C" Class 1E Electrical Room AHU C Fans	VBS-MA-05C VBS-MA-06C	Yes (Run Status)	Start
Division "B" and "D" Class 1E Electrical Room AHU B Fans	VBS-MA-05B VBS-MA-06B	Yes (Run Status)	Start
Division "B" and "D" Class 1E Electrical Room AHU D Fans	VBS-MA-05D VBS-MA-06D	Yes (Run Status)	Start
Division "A" and "C" Class 1E Battery Room Exhaust Fans	VBS-MA-07A VBS-MA-07C	Yes (Run Status)	Start
Division "B" and "D" Class 1E Battery Room Exhaust Fans	VBS-MA-07B VBS-MA-07D	Yes (Run Status)	Start
MCR Ancillary Fans	VBS-MA-10A VBS-MA-10B	No	Run
Division B Room Ancillary Fan	VBS-MA-11	No	Run
Division C Room Ancillary Fan	VBS-MA-12	No	Run

Table 2.7.1-4
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the VBS is as described in the Design Description of this subsection 2.7.1	Inspection of the as-built system will be performed.	The as-built VBS conforms with the functional arrangement described in the Design Description of this subsection 2.7.1.
2.a) The components identified in Table 2.7.1-1 as ASME Code Section III are designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built components as documented in the ASME design reports.	The ASME Code Section III design reports exist for the as-built components identified in Table 2.7.1-1 as ASME Code Section III.
2.b) The piping identified in Table 2.7.1-2 as ASME Code Section III is designed and constructed in accordance with ASME Code Section III requirements.	Inspection will be conducted of the as-built components as documented in the ASME design reports.	The ASME code Section III design reports exist for the as-built piping identified in Table 2.7.1-2 as ASME Code Section III.
3.a) Pressure boundary welds in components identified in Table 2.7.1-1 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for nondestructive examination of pressure boundary welds.
3.b) Pressure boundary welds in piping identified in Table 2.7.1-2 as ASME Code Section III meet ASME Code Section III requirements.	Inspection of the as-built pressure boundary welds will be performed in accordance with the ASME Code Section III.	A report exists and concludes that the ASME Code Section III requirements are met for nondestructive examination of pressure boundary welds.
4.a) The components identified in Table 2.7.1-1 as ASME Code Section III retain their pressure boundary integrity at their design pressure.	A hydrostatic test will be performed on the components required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the pressure test of the components identified in Table 2.7.1-1 as ASME Code Section III conform with the requirements of the ASME Code Section III.
4.b) The piping identified in Table 2.7.1-2 as ASME Code Section III retains its pressure boundary integrity at its design pressure.	A hydrostatic test will be performed on the piping required by the ASME Code Section III to be hydrostatically tested.	A report exists and concludes that the results of the pressure test of the piping identified in Table 2.7.1-2 as ASME Code Section III conform with the requirements of the ASME Code Section III.

Table 2.7.1-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. The seismic Category I equipment identified in Table 2.7.1-1 can withstand seismic design basis loads without loss of safety function.	i) Inspection will be performed to verify that the seismic Category I equipment identified in Table 2.7.1-1 is located on the Nuclear Island.	i) The seismic Category I equipment identified in Table 2.7.1-1 is located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis loads without loss of safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) A report exists and concludes that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.
6.a) The Class 1E components identified in Table 2.7.1-1 are powered from their respective Class 1E division.	Testing will be performed on the VBS by providing a simulated test signal in each Class 1E division.	A simulated test signal exists at the Class 1E equipment identified in Table 2.7.1-1 when the assigned Class 1E division is provided the test signal.
6.b) Separation is provided between VBS Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.	See Tier 1 Material, Table 3.3-6, item 7.d.	See Tier 1 Material, Table 3.3-6, item 7.d.
7. The VBS provides the safety-related function to isolate the pipe that penetrates the MCR pressure boundary.	See item 10.b in this table.	See item 10.b in this table.
8.a) The VBS provides cooling to the MCR, TSC, RSR, and Class 1E electrical rooms.	See item 12 in this table.	See item 12 in this table.
8.b) The VBS provides ventilation cooling to the Class 1E battery rooms.	See item 12 in this table.	See item 12 in this table.

Table 2.7.1-4 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
8.c) The VBS maintains MCR and TSC habitability when radioactivity is detected.	See item 12 in this table.	See item 12 in this table.
8.d) The VBS provides ventilation cooling via the ancillary equipment in Table 2.7.1-3 to the MCR and the division B&C Class 1E I&C rooms.	Testing will be performed on the components in Table 2.7.1-3.	The fans start and run.
9. Safety-related displays identified in Table 2.7.1-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the safety-related displays in the MCR.	Safety-related displays identified in Table 2.7.1-1 can be retrieved in the MCR.
10.a) Controls exist in the MCR to cause the remotely operated valves identified in Table 2.7.1-1 to perform their active functions.	Stroke testing will be performed on the remotely operated valves identified in Table 2.7.1-1 using the controls in the MCR.	Controls in the MCR operate to cause the remotely operated valves identified in Table 2.7.1-1 to perform their active functions.
10.b) The valves identified in Table 2.7.1-1 as having PMS control perform their active safety function after receiving a signal from the PMS.	Testing will be performed using real or simulated signals into the PMS.	The valves identified in Table 2.7.1-1 as having PMS control perform their active safety function after receiving a signal from PMS.
11. After loss of motive power, the valves identified in Table 2.7.1-1 assume the indicated loss of motive power position.	Testing of the installed valves will be performed under the conditions of loss of motive power.	Upon loss of motive power, each remotely operated valves identified in Table 2.7.1-1 assumes the indicated loss of motive power position.
12. Controls exist in the MCR to cause the components identified in Table 2.7.1-3 to perform the listed function.	Testing will be performed on the components in Table 2.7.1-3 using controls in the MCR.	Controls in the MCR operate to cause the components listed in Table 2.7.1-3 to perform the listed functions.
13. Displays of the parameters identified in Table 2.7.1-3 can be retrieved in the MCR.	Inspection will be performed for retrievability of the parameters in the MCR.	The displays identified in Table 2.7.1-3 can be retrieved in the MCR.
14. The background noise level in the MCR and RSR does not exceed 65 dB(A) when the VBS is operating.	The as-built VBS will be operated, and background noise levels in the MCR and RSR will be measured.	The background noise level in the MCR and RSR does not exceed 65 dB(A) when the VBS is operating.

Table 2.7.1-5		
Component Name	**Tag No.**	**Component Location**
Supplemental Air Filtration Unit A	VBS-MS-01A	Auxiliary Building
Supplemental Air Filtration Unit B	VBS-MS-01B	Auxiliary Building
MCR/TSC Supply Air Handling Unit A	VBS-MS-02A	Auxiliary Building
MCR/TSC Supply Air Handling Unit B	VBS-MS-02B	Annex Building
Division "A" and "C" Class 1E Electrical Room AHU A	VBS-MS-03A	Auxiliary Building
Division "A" and "C" Class 1E Electrical Room AHU C	VBS-MS-03C	Auxiliary Building
Division "B" and "D" Class 1E Electrical Room AHU B	VBS-MS-03B	Auxiliary Building
Division "B" and "D" Class 1E Electrical Room AHU D	VBS-MS-03D	Auxiliary Building
MCR Toilet Exhaust Fan	VBS-MA-04	Auxiliary Building
Division "A&C" Class 1E Battery Room Exhaust Fan	VBS-MA-07A	Auxiliary Building
Division "A&C" Class 1E Battery Room Exhaust Fan	VBS-MA-07C	Auxiliary Building
Division "B&D" Class 1E Battery Room Exhaust Fan	VBS-MA-07B	Auxiliary Building
Division "B&D" Class 1E Battery Room Exhaust Fan	VBS-MA-07D	Auxiliary Building
PCS Valve Room Vent Fan	VBS-MA-08	Auxiliary Building
TSC Toilet Exhaust Fan	VBS-MA-09	Annex Building
MCR Ancillary Fan A	VBS-MA-10A	Auxiliary Building
MCR Ancillary Fan B	VBS-MA-10B	Auxiliary Building
Division B Ancillary Fan	VBS-MA-11	Auxiliary Building
Division C Ancillary Fan	VBS-MA-12	Auxiliary Building

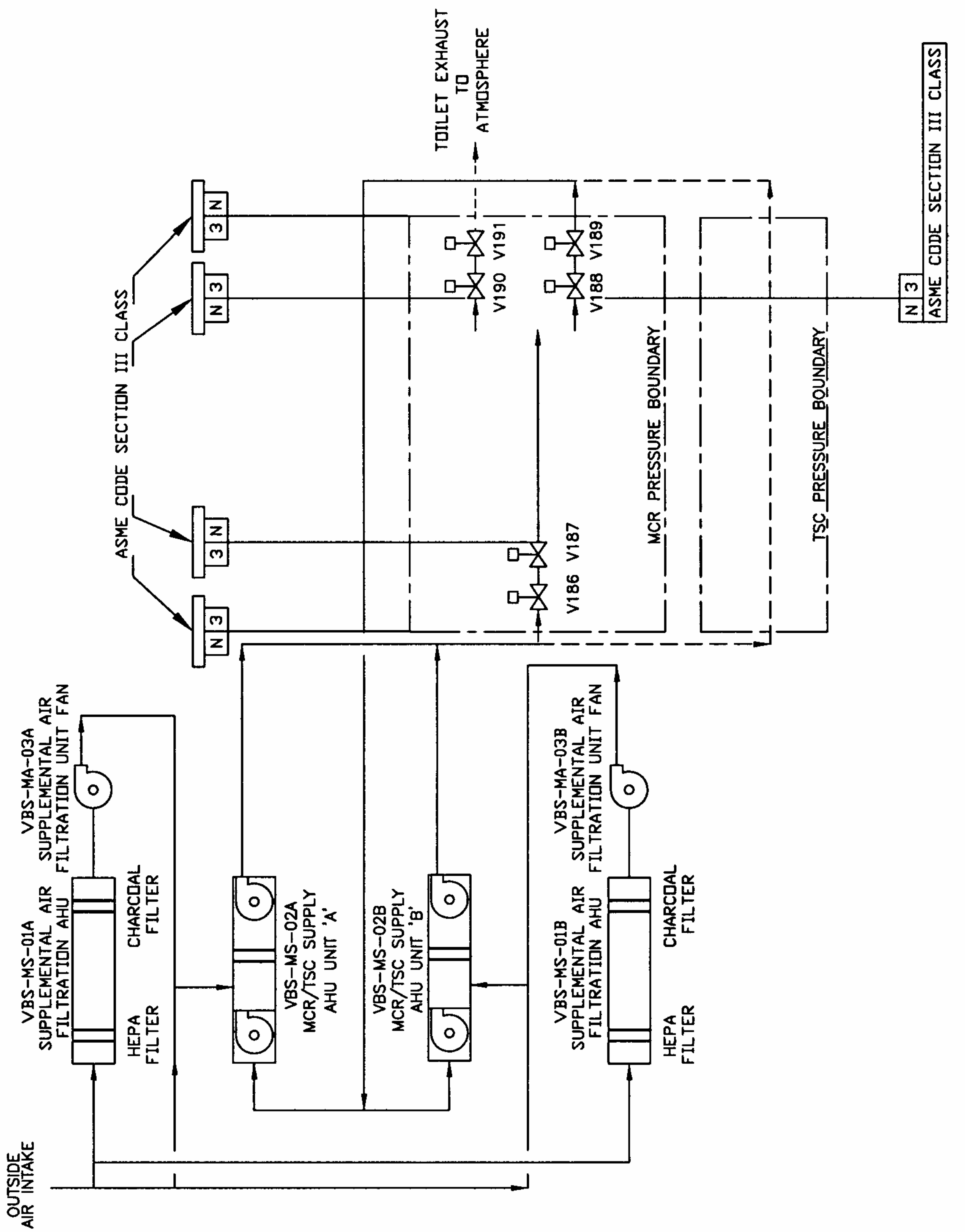


Figure 2.7.1-1 (Sheet 1 of 2)
Nuclear Island Nonradioactive Ventilation System

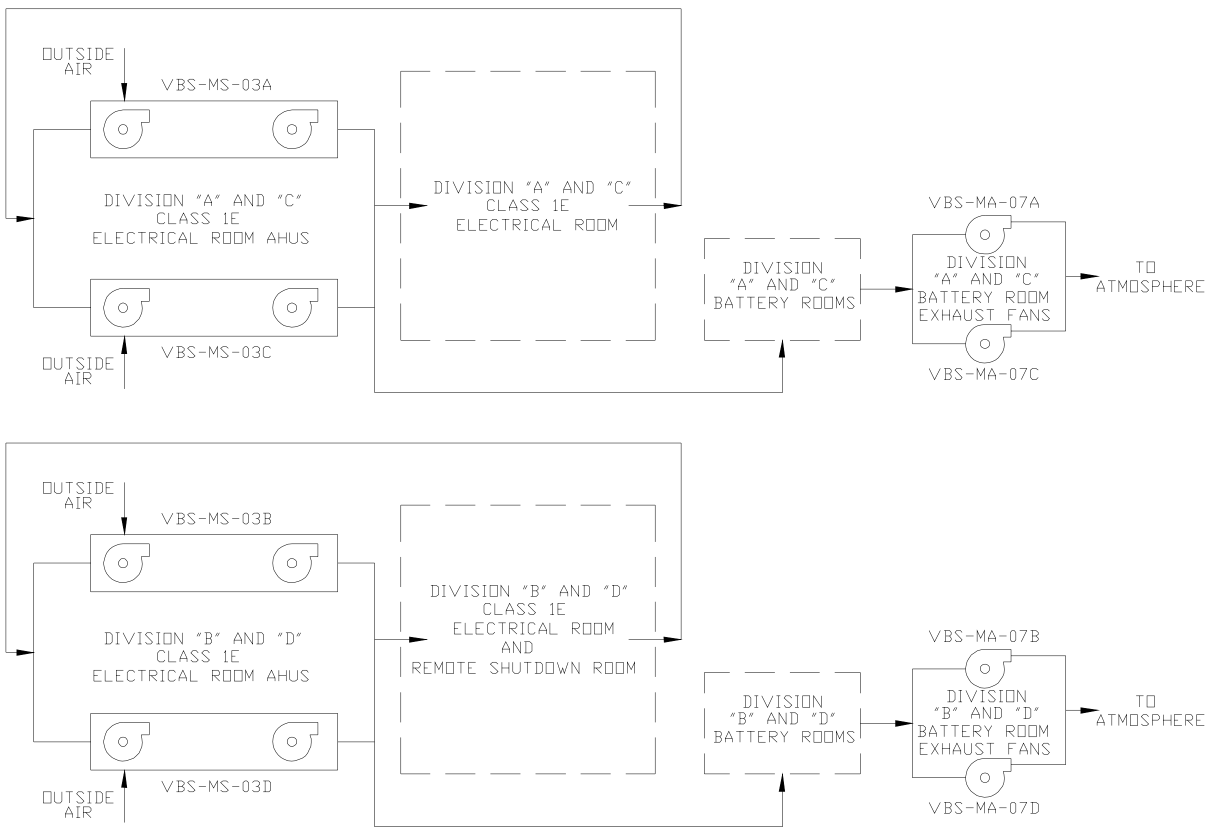


Figure 2.7.1-1 (Sheet 2 of 2)
Nuclear Island Nonradioactive Ventilation System

2.7.2 Central Chilled Water System

Design Description

The plant heating, ventilation, and air conditioning (HVAC) systems require chilled water as a cooling medium to satisfy the ambient air temperature requirements for the plant. The central chilled water system (VWS) supplies chilled water to the HVAC systems and is functional during reactor full-power and shutdown operation. The VWS also provides chilled water to selected process systems.

The VWS is as shown in Figure 2.7.2-1 and the component locations of the VWS are as shown Table 2.7.2-3.

1. The functional arrangement of the VWS is as described in the Design Description of this Section 2.7.2.

2. The VWS provides the safety-related function of preserving containment integrity by isolation of the VWS lines penetrating the containment.

3. The VWS provides the following nonsafety-related functions:

   a) The VWS provides chilled water to the supply air handling units serving the MCR, the Class 1E electrical rooms, and the unit coolers serving the RNS and CVS pump rooms.

   b) The VWS air-cooled chillers transfer heat from the VWS to the surrounding atmosphere.

4. Controls exist in the MCR to cause the components identified in Table 2.7.2-1 to perform the listed function.

5. Displays of the parameters identified in Table 2.7.2-1 can be retrieved in the MCR.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.7.2-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the VWS.

Table 2.7.2-1			
Equipment Name	**Tag No.**	**Display**	**Control Function**
Air-cooled Chiller	VWS-MS-02	Yes (Run Status)	Start
Air-cooled Chiller	VWS-MS-03	Yes (Run Status)	Start
Air-cooled Chiller Pump	VWS-MP-02	Yes (Run Status)	Start
Air-cooled Chiller Pump	VWS-MP-03	Yes (Run Status)	Start
CVS Pump Room Unit Cooler Fan A	VAS-MA-07A	Yes (Run Status)	Start
CVS Pump Room Unit Cooler Fan B	VAS-MA-07B	Yes (Run Status)	Start
RNS Pump Room Unit Cooler Fan A	VAS-MA-08A	Yes (Run Status)	Start
RNS Pump Room Unit Cooler Fan B	VAS-MA-08B	Yes (Run Status)	Start
Air-cooled Chiller Water Valve	VWS-PL-V210	Yes (Position Status)	Open
Air-cooled Chiller Water Valve	VWS-PL-V253	Yes (Position Status)	Open

Table 2.7.2-2
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the VWS is as described in the Design Description of this Section 2.7.2.	Inspection of the as-built system will be performed.	The as-built VWS conforms with the functional arrangement as described in the Design Description of this Section 2.7.2.
2. The applicable portions of the VWS provide the safety-related function of preserving containment integrity by isolation of the VWS lines penetrating the containment.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.
3.a) The VWS provides chilled water to the supply air handling units serving the MCR, the Class 1E electrical rooms, and the unit coolers serving the RNS and CVS pump rooms.	Testing will be performed by measuring the flow rates to the chilled water cooling coils.	The water flow to each cooling coil equals or exceeds the following: Coil — Flow (gpm) VBS MY C01A/B 138 VBS MY C02A/C 108 VBS MY C02B/D 84 VAS MY C07A/B 24 VAS MY C12A/B 15 VAS MY C06A/B 15
3.b) The VWS air-cooled chillers transfer heat from the VWS to the surrounding atmosphere.	Inspection will be performed for the existence of a report that determines the heat transfer capability of each air-cooled chiller.	A report exists and concludes that the heat transfer rate of each air-cooled chiller is greater than or equal to 230 tons.
4. Controls exist in the MCR to cause the components identified in Table 2.7.2-1 to perform the listed function.	Testing will be performed on the components in Table 2.7.2-1 using controls in the MCR.	Controls in the MCR operate to cause the components listed in Table 2.7.2-1 to perform the listed functions.
5. Displays of the parameters identified in Table 2.7.2-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of parameters in the MCR.	The displays identified in Table 2.7.2-1 can be retrieved in the MCR.

Table 2.7.2-3		
Component Name	**Tag No.**	**Component Location**
Water Chiller Pump A	VWS-MP-01A	Turbine Building
Water Chiller Pump B	VWS-MP-01B	Turbine Building
Air Cooled Chiller Pump 2	VWS-MP-02	Auxiliary Building
Air Cooled Chiller Pump 3	VWS-MP-03	Auxiliary Building
Water Chiller A	VWS-MS-01A	Turbine Building
Water Chiller B	VWS-MS-01B	Turbine Building
Air Cooled Chiller 2	VWS-MS-02	Auxiliary Building
Air Cooled Chiller 3	VWS-MS-03	Auxiliary Building

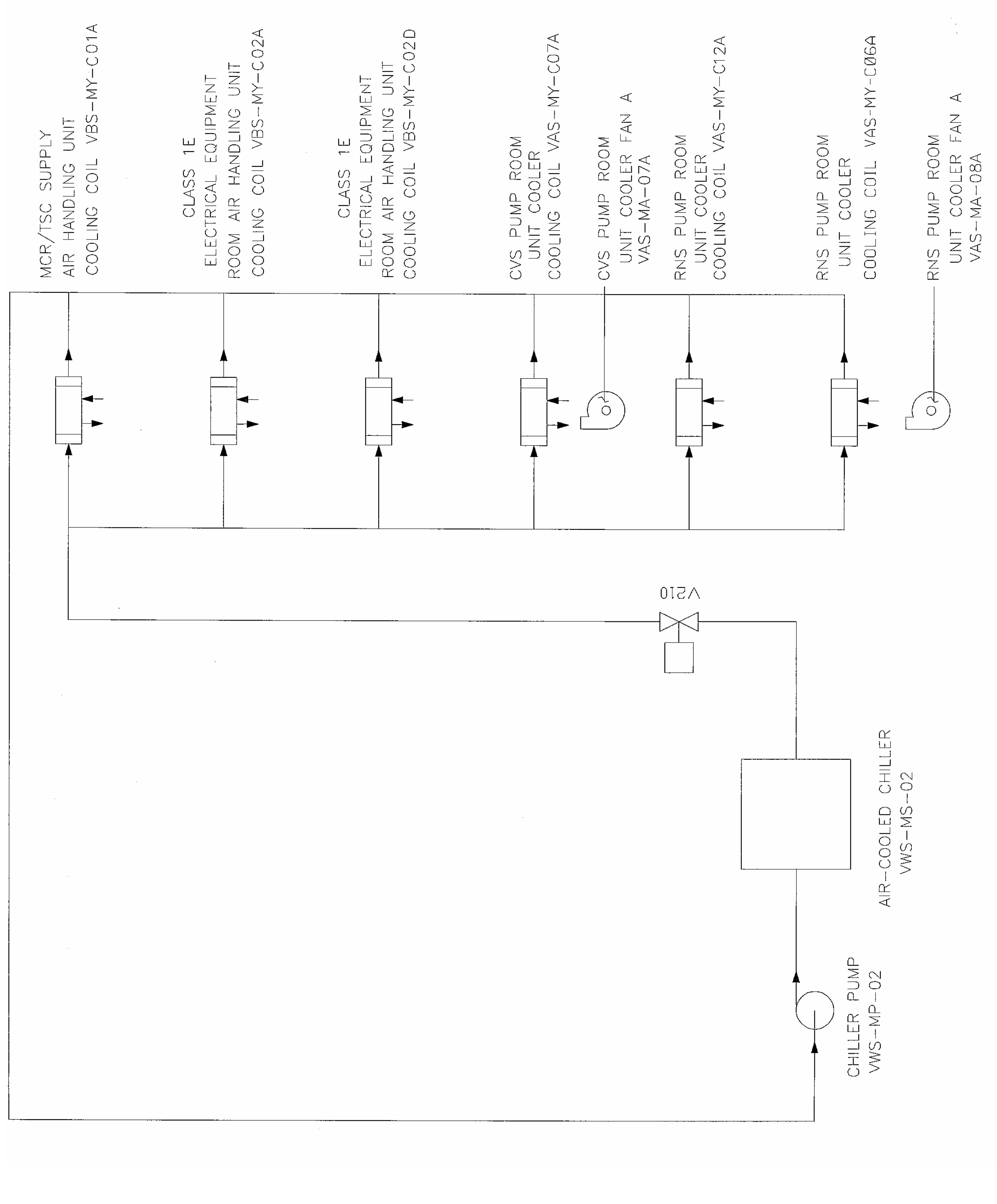


Figure 2.7.2-1 (Sheet 1 of 2)
Central Chilled Water System

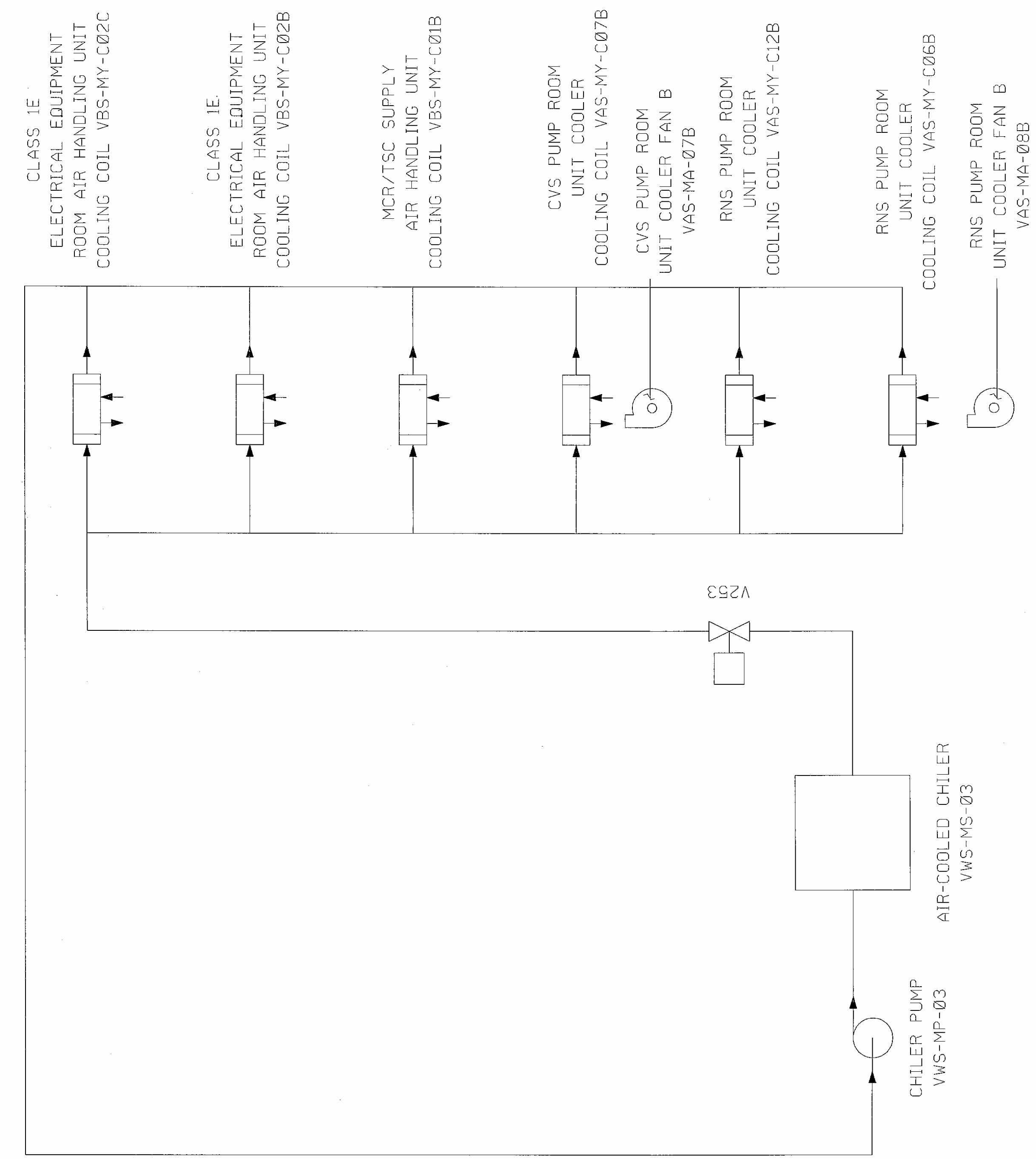


Figure 2.7.2-1 (Sheet 2 of 2)
Central Chilled Water System

2.7.3 Annex/Auxiliary Building Nonradioactive Ventilation System

Design Description

The annex/auxiliary buildings nonradioactive HVAC system (VXS) serves the nonradioactive personnel and equipment areas, electrical equipment rooms, clean corridors, the ancillary diesel generator room and demineralized water deoxygenating room in the annex building, and the main steam isolation valve compartments, reactor trip switchgear rooms, and piping and electrical penetration areas in the auxiliary building. The VXS consists of the following independent subsystems: the general area HVAC subsystem, the switchgear room HVAC subsystem, the equipment room HVAC subsystem, the MSIV compartment HVAC subsystem, the mechanical equipment areas HVAC subsystem and the valve/piping penetration room HVAC subsystem.

The VXS is as shown in Figure 2.7.3-1 and the component locations of the VXS are as shown in Table 2.7.3-3.

1. The functional arrangement of the VXS is as described in the Design Description of this Section 2.7.3.

2. The VXS provides the following nonsafety-related functions:

   a) The VXS provides cooling to the electrical switchgear, the battery charger, and the annex building nonradioactive air handling equipment rooms.

   b) The VXS provides ventilation cooling to the electrical switchgear, the battery charger, and the annex building nonradioactive air handling equipment rooms when the ZOS operates during a loss of offsite power coincident with loss of chilled water.

3. Controls exist in the main control room (MCR) to cause the components identified in Table 2.7.3-1 to perform the listed function.

4. Displays of the parameters identified in Table 2.7.3-1 can be retrieved in the MCR.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.7.3-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the VXS.

Table 2.7.3-1

Equipment Name	Tag No.	Display	Control Function
Switchgear Room Air Handling Units (AHU) A Fans	VXS-MA-05A VXS-MA-06A	Yes (Run Status)	Start
Switchgear Room AHU B Fans	VXS-MA-05B VXS-MA-06B	Yes (Run Status)	Start
Equipment Room AHU A Fans	VXS-MA-01A VXS-MA-02A	Yes (Run Status)	Start
Equipment Room AHU B Fans	VXS-MA-01B VXS-MA-02B	Yes (Run Status)	Start

Table 2.7.3-2
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the VXS is as described in the Design Description of this Section 2.7.3.	Inspection of the as-built system will be performed.	The as-built VXS conforms with the functional arrangement described in the Design Description of this Section 2.7.3.
2.a) The VXS provides cooling to the electrical switchgear, the battery charger, and the annex building nonradioactive air handling equipment rooms when the ZOS operates and chilled water is available.	See item 3 in this table.	See item 3 in this table.
2.b) The VXS provides ventilation cooling to the electrical switchgear, the battery charger, and the annex building nonradioactive air handling equipment rooms when the ZOS operates during a loss of offsite power coincident with loss of chilled water.	See item 3 in this table.	See item 3 in this table.
3. Controls exist in the MCR to cause the components identified in Table 2.7.3-1 to perform the listed function.	Testing will be performed on the components in Table 2.7.3-1 using controls in the MCR.	Controls in the MCR operate to cause the components listed in Table 2.7.3-1 to perform the listed functions.
4. Displays of the parameters identified in Table 2.7.3-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the parameters in the MCR.	The displays identified in Table 2.7.3-1 can be retrieved in the MCR.

Table 2.7.3-3		
Component Name	**Tag No.**	**Component Location**
Annex Building General Area AHU A	VXS-MS-01A	Annex Building
Annex Building General Area AHU B	VXS-MS-01B	Annex Building
Annex Building Equipment Room AHU A	VXS-MS-02A	Annex Building
Annex Building Equipment Room AHU B	VXS-MS-02B	Annex Building
MSIV Compartment A AHU-A	VXS-MS-04A	Auxiliary Building
MSIV Compartment B AHU-B	VXS-MS-04B	Auxiliary Building
MSIV Compartment B AHU-C	VXS-MS-04C	Auxiliary Building
MSIV Compartment A AHU-D	VXS-MS-04D	Auxiliary Building
Switchgear Room AHU A	VXS-MS-05A	Annex Building
Switchgear Room AHU B	VXS-MS-05B	Annex Building
Mechanical Equipment Area AHU Unit A	VXS-MS-07A	Annex Building
Mechanical Equipment Area AHU Unit B	VXS-MS-07B	Annex Building
Valve/Piping Penetration Room AHU A	VXS-MS-08A	Auxiliary Building
Valve/Piping Penetration Room AHU B	VXS-MS-08B	Auxiliary Building
Battery Room #1 Exhaust Fan	VXS-MA-09A	Annex Building
Battery Room #2 Exhaust Fan	VXS-MA-09B	Annex Building
Toilet Exhaust Fan	VXS-MA-13	Annex Building
Annex Building Nonradioactive Air Handling Equipment Room Unit Heater A	VXS-MY-W01A	Annex Building
Annex Building Nonradioactive Air Handling Equipment Room Unit Heater B	VXS-MY-W01B	Annex Building
Annex Building Nonradioactive Air Handling Equipment Room Unit Heater C	VXS-MY-W01C	Annex Building

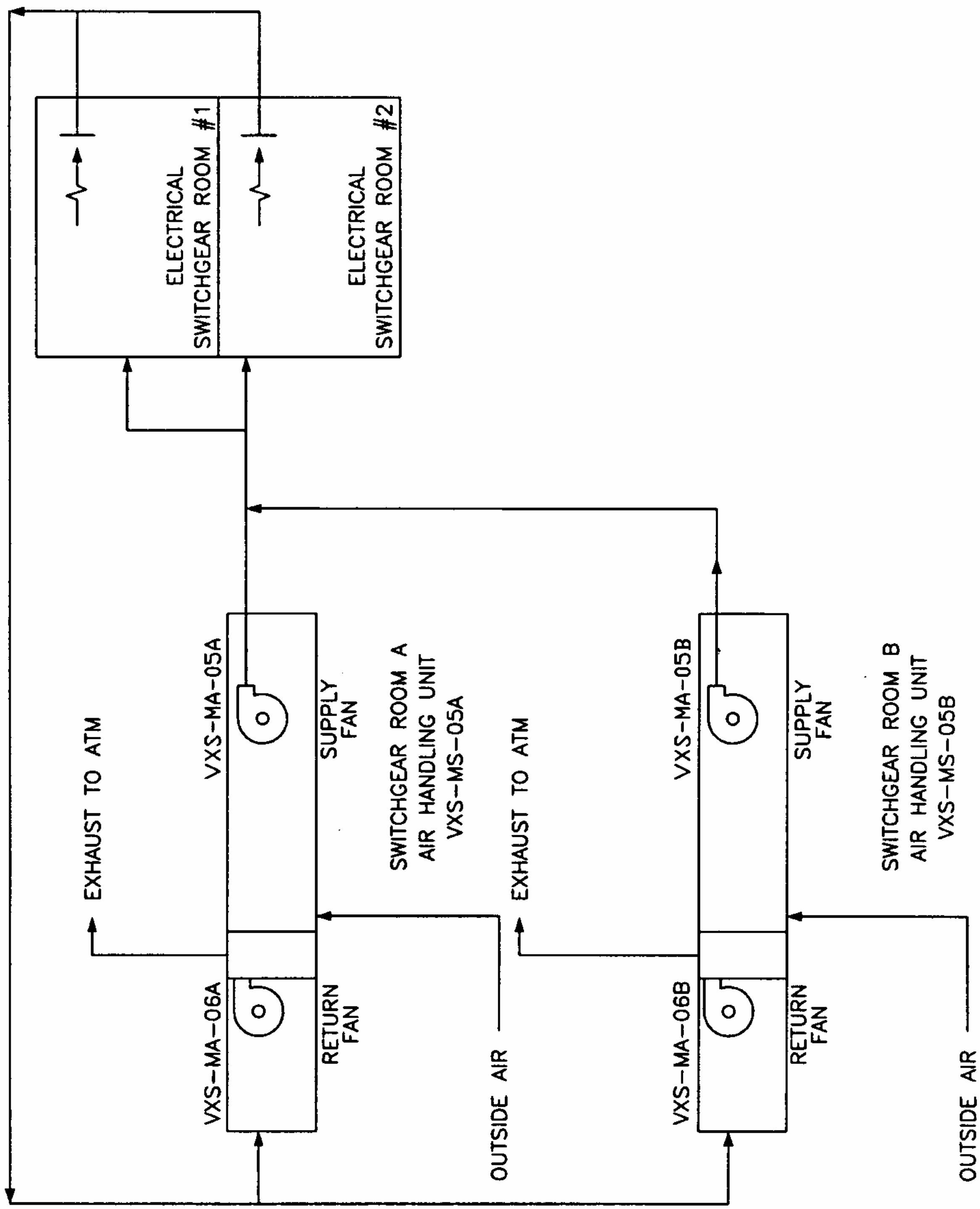


Figure 2.7.3-1 (Sheet 1 of 2)
Annex/Auxiliary Building Nonradioactive Ventilation System

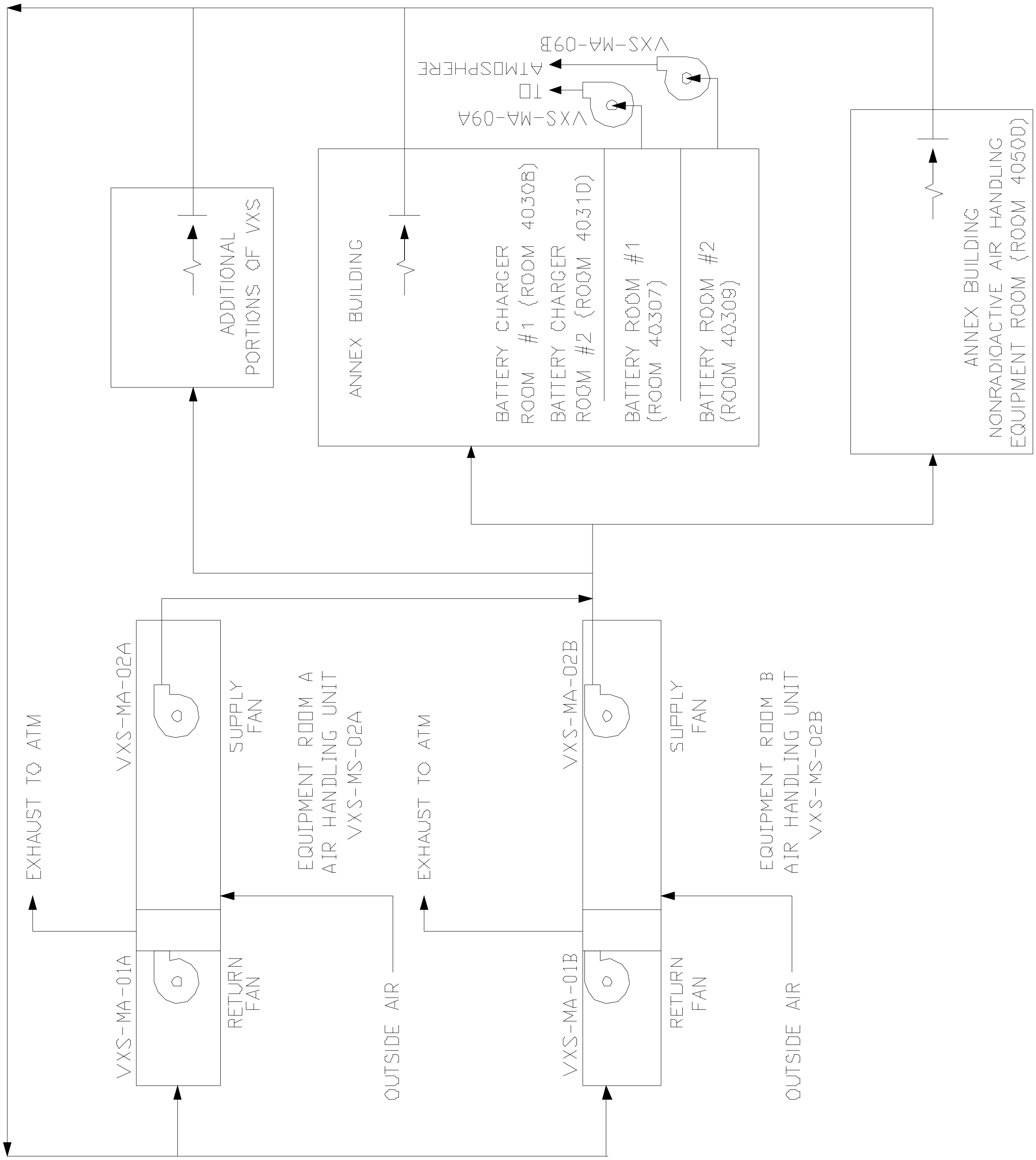


Figure 2.7.3-1 (Sheet 2 of 2)
Annex/Auxiliary Building Nonradioactive Ventilation System

2.7.4 Diesel Generator Building Ventilation System

Design Description

The diesel generator building ventilation system (VZS) provides ventilation cooling of the diesel generator building for the onsite standby power system. The VZS also provides heating and ventilation within the diesel oil transfer module enclosure. The VZS consists of the following subsystems: the normal diesel building heating and ventilation subsystem, the standby diesel building exhaust ventilation subsystem, the fuel oil day tank vault exhaust subsystem and the diesel oil transfer module enclosures ventilation and heating subsystem.

The VZS is as shown in Figure 2.7.4-1 and the component locations of the VZS are as shown in Table 2.7.4-3.

1. The functional arrangement of the VZS is as described in the Design Description of this Section 2.7.4.

2. The VZS provides the following nonsafety-related functions:

   a) The VZS provides ventilation cooling to the diesel generator rooms when the diesel generators are operating.

   b) The VZS provides ventilation cooling to the electrical equipment service modules when the diesel generators are operating.

   c) The VZS provides normal heating and ventilation to the diesel oil transfer module enclosure.

3. Controls exist in the main control room (MCR) to cause the components identified in Table 2.7.4-1 to perform the listed functions.

4. Displays of the parameters identified in Table 2.7.4-1 can be retrieved in the MCR.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.7.4-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the VZS.

Table 2.7.4-1			
Equipment Name	**Tag No.**	**Display**	**Control Function**
Diesel Generator Room A Standby Exhaust Fans	VZS-MY-V01A VZS-MY-V02A	Yes (Run Status)	Start
Diesel Generator Room B Standby Exhaust Fans	VZS-MY-V01B VZS-MY-V02B	Yes (Run Status)	Start
Service Module A Air Handling Units (AHU) Supply Fan	VZS-MA-01A	Yes (Run Status)	Start
Service Module B AHU Supply Fan	VZS-MA-01B	Yes (Run Status)	Start
Diesel Oil Transfer Module Enclosure A Exhaust Fan	VZS-MY-V03A	Yes (Run Status)	Start
Diesel Oil Transfer Module Enclosure A Electric Unit Heater	VZS-MY-U03A	Yes (Run Status)	Energize
Diesel Oil Transfer Module Enclosure B Exhaust Fan	VZS-MY-V03B	Yes (Run Status)	Start
Diesel Oil Transfer Module Enclosure B Electric Unit Heater	VZS-MY-U03B	Yes (Run Status)	Energize

Table 2.7.4-2
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the VZS is as described in the Design Description of this Section 2.7.4.	Inspection of the as-built system will be performed.	The as-built VZS conforms with the functional arrangement described in the Design Description of this Section 2.7.4.
2.a) The VZS provides ventilation cooling to the diesel generator rooms when the diesel generators are operating.	See item 3 in this table.	See item 3 in this table.
2.b) The VZS provides ventilation cooling to the electrical equipment service modules when the diesel generators are operating.	See item 3 in this table.	See item 3 in this table.
2.c) The VZS provides normal heating and ventilation to the diesel oil transfer module enclosure.	See item 3 in this table.	See item 3 in this table.
3. Controls exist in the MCR to cause the components identified in Table 2.7.4-1 to perform the listed function.	Testing will be performed on the components in Table 2.7.4-1 using controls in the MCR.	Controls in the MCR operate to cause the components listed in Table 2.7.4-1 to perform the listed functions.
4. Displays of the parameters identified in Table 2.7.4-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the parameters in the MCR.	The displays identified in Table 2.7.4-1 can be retrieved in the MCR.

Table 2.7.4-3		
Component Name	**Tag No.**	**Component Location**
Service Module AHU A	VZS-MS-01A	Diesel-Generator Building
Service Module AHU B	VZS-MS-01B	Diesel-Generator Building
Diesel Oil Transfer Module Enclosure A Unit Heater	VZS-MY-U03A	Yard
Diesel Oil Transfer Module Enclosure B Unit Heater	VZS-MY-U03B	Yard
D/G Building Standby Exhaust Fan 1A	VZS-MY-V01A	Diesel-Generator Building
D/G Building Standby Exhaust Fan 1B	VZS-MY-V01B	Diesel-Generator Building
D/G Building Standby Exhaust Fan 2A	VZS-MY-V02A	Diesel-Generator Building
D/G Building Standby Exhaust Fan 2B	VZS-MY-V02B	Diesel-Generator Building
Diesel Oil Transfer Module Enclosure A Exhaust Fan	VZS-MY-V03A	Yard
Diesel Oil Transfer Module Enclosure B Exhaust Fan	VZS-MY-V03B	Yard
Fuel Oil Day Tank Vault Exhaust Fan	VZS-MA-02A	Diesel-Generator Building
Fuel Oil Day Tank Vault Exhaust Fan	VZS-MA-02B	Diesel-Generator Building

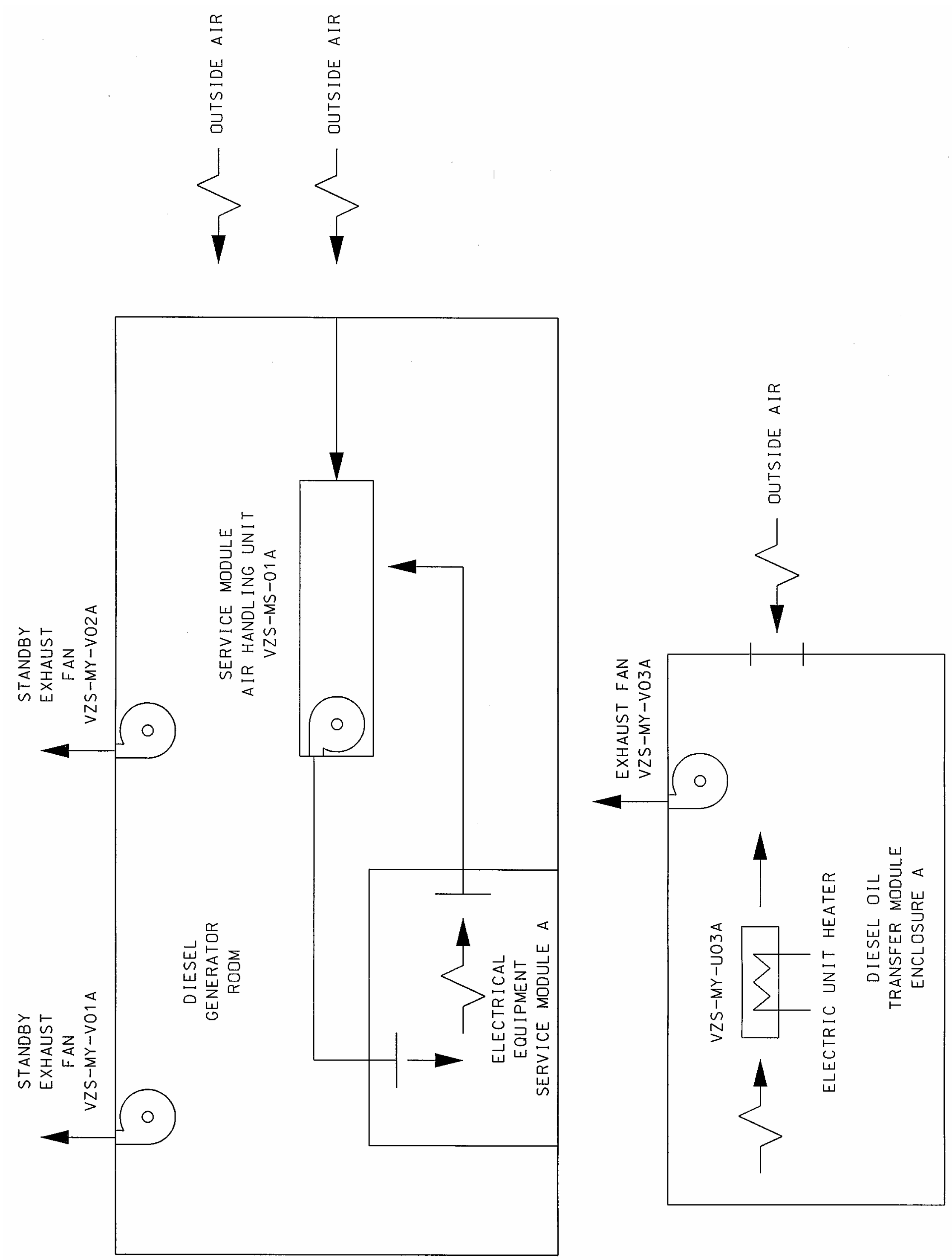


Figure 2.7.4-1 (Sheet 1 of 2)
Diesel Generator Building Ventilation System

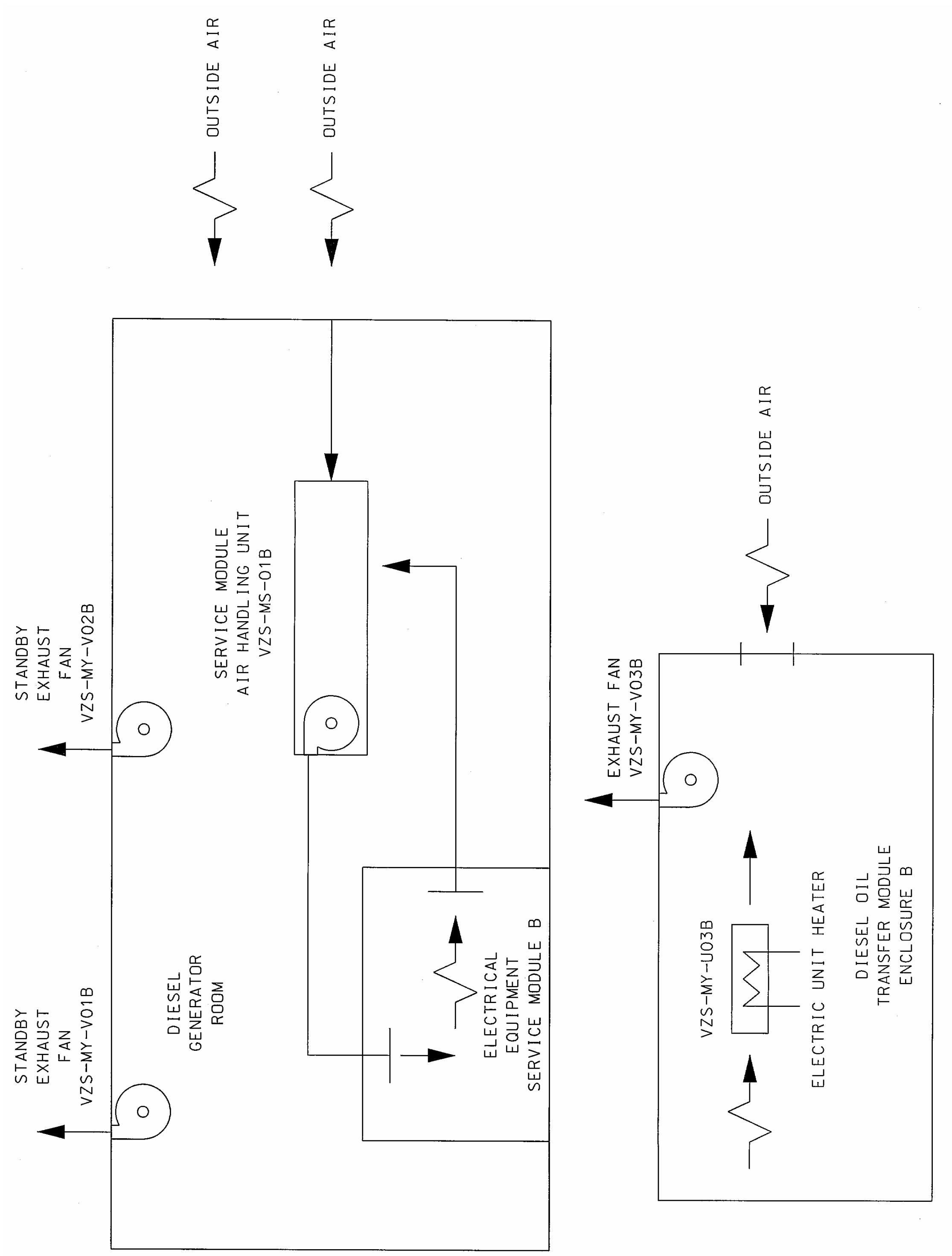


Figure 2.7.4-1 (Sheet 2 of 2)
Diesel Generator Building Ventilation System

2.7.5 Radiologically Controlled Area Ventilation System

Design Description

The radiologically controlled area ventilation system (VAS) serves the fuel handling area of the auxiliary building, and the radiologically controlled portions of the auxiliary and annex buildings, except for the health physics and hot machine shop areas, which are provided with a separate ventilation system (VHS). The VAS consists of two subsystems: the auxiliary/annex building ventilation subsystem and the fuel handling area ventilation subsystem. The subsystems provide ventilation to maintain occupied areas, and access and equipment areas within their design temperature range. They provide outside air for plant personnel and prevent the unmonitored release of airborne radioactivity to the atmosphere or adjacent plant areas. The VAS automatically isolates selected building areas by closing the supply and exhaust duct isolation dampers and starts the containment air filtration system (VFS) when high airborne radioactivity in the exhaust air duct or high ambient pressure differential is detected.

The component locations of the VAS are as shown in Table 2.7.5-3.

1. The functional arrangement of the VAS is as described in the Design Description of this Section 2.7.5.

2. The VAS maintains each building area at a slightly negative pressure relative to the atmosphere or adjacent clean plant areas.

3. Displays of the parameters identified in Table 2.7.5-1 can be retrieved in the main control room (MCR).

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.7.5-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the VAS.

Table 2.7.5-1

Equipment	Tag No.	Display	Control Function
Annex Building Pressure Differential Indicator	VAS-032	Yes	-
Auxiliary Building Pressure Differential Indicator	VAS-033	Yes	-
Fuel Handling Area Pressure Differential Indicator	VAS-030	Yes	-

Note: Dash (-) indicates not applicable.

Table 2.7.5-2
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the VAS is as described in the Design Description of this Section 2.7.5.	Inspection of the as-built system will be performed.	The as-built VAS conforms with the functional arrangement described in the Design Description of this Section 2.7.5.
2. The VAS maintains each building area at a slightly negative pressure relative to the atmosphere or adjacent clean plant areas.	i) Testing will be performed to confirm that the VAS maintains each building at a slightly negative pressure when operating all VAS supply AHUs and all VAS exhaust fans.	i) The time average pressure differential in the served areas of the annex, fuel handling and radiologically controlled auxiliary buildings as measured by each of the instruments identified in Table 2.7.5-1 is negative.
	ii) Testing will be performed to confirm the ventilation flow rate through the auxiliary building fuel handling area when operating all VAS supply AHUs and all VAS exhaust fans.	ii) A report exists and concludes that the calculated exhaust flow rate based on the measured flow rates is greater than or equal to 15,300 cfm.
	iii) Testing will be performed to confirm the auxiliary building radiologically controlled area ventilation flow rate when operating all VAS supply AHUs and all VAS exhaust fans.	iii) A report exists and concludes that the calculated exhaust flow rate based on the measured flow rates is greater than or equal to 22,500 cfm.
3. Displays of the parameters identified in Table 2.7.5-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the parameters in the MCR.	The displays identified in Table 2.7.5-1 can be retrieved in the MCR.

Table 2.7.5-3		
Component Name	**Tag No.**	**Component Location**
Auxiliary/Annex Building Supply AHU A	VAS-MS-01A	Annex Building
Auxiliary/Annex Building Supply AHU B	VAS-MS-01B	Annex Building
Fuel Handling Area Supply AHU A	VAS-MS-02A	Annex Building
Fuel Handling Area Supply AHU B	VAS-MS-02B	Annex Building
CVS Pump Room Unit Cooler A	VAS-MS-05A	Auxiliary Building
CVS Pump Room Unit Cooler B	VAS-MS-05B	Auxiliary Building
RNS Pump Room Unit Cooler A	VAS-MS-06A	Auxiliary Building
RNS Pump Room Unit Cooler B	VAS-MS-06B	Auxiliary Building
Auxiliary/Annex Building Exhaust Fan A	VAS-MA-02A	Auxiliary Building
Auxiliary/Annex Building Exhaust Fan B	VAS-MA-02B	Auxiliary Building
Fuel Handling Area Exhaust Fan A	VAS-MA-06A	Auxiliary Building
Fuel Handling Area Exhaust Fan B	VAS-MA-06B	Auxiliary Building

2.7.6 Containment Air Filtration System

Design Description

The containment air filtration system (VFS) provides intermittent flow of outdoor air to purge and filter the containment atmosphere of airborne radioactivity during normal plant operation, and continuous flow during hot or cold plant shutdown conditions to reduce airborne radioactivity levels for personnel access. The VFS can also provide filtered exhaust for the radiologically controlled area ventilation system (VAS) during abnormal conditions.

The VFS is as shown in Figure 2.7.6-1 and the component locations of the VFS are as shown in Table 2.7.6-3.

1. The functional arrangement of the VFS is as described in the Design Description of this Section 2.7.6.

2. The VFS provides the safety-related function of preserving containment integrity by isolation of the VFS lines penetrating containment.

3. The VFS provides the intermittent flow of outdoor air to purge the containment atmosphere during normal plant operation, and continuous flow during hot or cold plant shutdown conditions.

4. Controls exist in the main control room (MCR) to cause the components identified in Table 2.7.6-1 to perform the listed function.

5. Displays of the parameters in Table 2.7.6-1 can be retrieved in the MCR.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.7.6-2 specifies the inspections, tests, analyses, and associated criteria for the VFS.

Table 2.7.6-1

Equipment	Tag No.	Display	Control Function
Containment Air Handling Units (AHU) Supply Fan A	VFS-MA-01A	Yes (Run Status)	Start
Containment AHU Supply Fan B	VFS-MA-01B	Yes (Run Status)	Start
Containment AHU Supply Fan A Flow Sensor	VFS-012A	Yes	-
Containment AHU Supply Fan B Flow Sensor	VFS-012B	Yes	-
Containment Exhaust Fan A	VFS-MA-02A	Yes (Run Status)	Start
Containment Exhaust Fan B	VFS-MA-02B	Yes (Run Status)	Start
Containment Exhaust Fan A Flow Sensor	VFS-011A	Yes	-
Containment Exhaust Fan B Flow Sensor	VFS-011B	Yes	-

Table 2.7.6-2

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The functional arrangement of the VFS is as described in the Design Description of this Section 2.7.6.	Inspection of the as-built system will be performed.	The as-built VFS conforms with the functional arrangement described in the Design Description of this Section 2.7.6.
2. The VFS provides the safety-related function of preserving containment integrity by isolation of the VFS lines penetrating containment.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.	See Tier 1 Material, Table 2.2.1-3, items 1 and 7.
3. The VFS provides the intermittent flow of outdoor air to purge the containment atmosphere during normal plant operation, and continuous flow during hot or cold plant shutdown conditions.	i) Testing will be performed to confirm that containment supply AHU fan A when operated with containment exhaust fan A provides a flow of outdoor air.	i) The flow rate measured at each fan is greater than or equal to 3,600 scfm.
	ii) Testing will be performed to confirm that containment supply AHU fan B when operated with containment exhaust fan B provides a flow of outdoor air.	ii) The flow rate measured at each fan is greater than or equal to 3,600 scfm.
	iii) Inspection will be conducted of the containment purge discharge line (VFS-L204) penetrating the containment.	iii) The <u>nominal</u> line size is ≥ 36 in.
4. Controls exist in the MCR to cause the components identified in Table 2.7.6-1 to perform the listed function.	Testing will be performed on the components in Table 2.7.6-1 using controls in the MCR.	Controls in the MCR operate to cause the components listed in Table 2.7.6-1 to perform the listed functions.
5. Displays of the parameters identified in Table 2.7.6-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the parameters in the MCR.	The displays identified in Table 2.7.6-1 can be retrieved in the MCR.

Table 2.7.6-3		
Component Name	**Tag No.**	**Component Location**
Containment Air Filtration Supply AHU A	VFS-MS-01A	Annex Building
Containment Air Filtration Supply AHU B	VFS-MS-01B	Annex Building
Containment Air Filtration Exhaust Unit A	VFS-MS-02A	Annex Building
Containment Air Filtration Exhaust Unit B	VFS-MS-02B	Annex Building

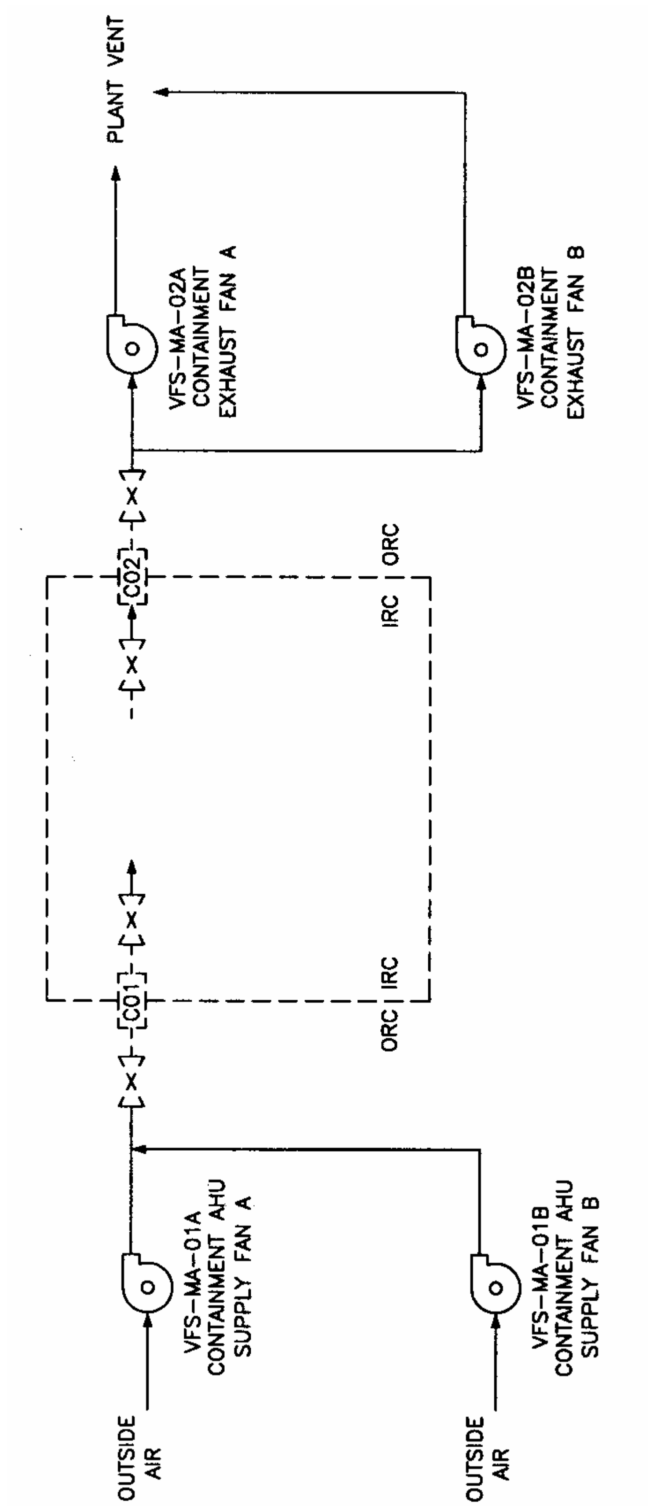


Figure 2.7.6-1
Containment Air Filtration System

2.7.7 Containment Recirculation Cooling System

Design Description

The containment recirculation cooling system (VCS) controls the containment air temperature and humidity during normal operation, refueling and shutdown.

The locations of the VCS are as shown in Table 2.7.7-3.

1. The functional arrangement of the VCS is as described in the Design Description of this Section 2.7.7.

2. Displays of the parameters identified in Table 2.7.7-1 can be retrieved in the main control room (MCR).

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.7.7-2 specifies the inspections, tests, analyses, and associated acceptance criteria for the VCS.

Table 2.7.7-1

Equipment Name	Tag No.	Display
Containment Temperature Channel	VCS-061	Yes
Containment Fan Cooler Fan	VCS-MA-01A VCS-MA-01C VCS-MA-01B VCS-MA-01D	Yes (Run Status) Yes (Run Status) Yes (Run Status) Yes (Run Status)

Note: Dash (-) indicates not applicable.

Table 2.7.7-2 Inspections, Tests, Analyses, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The functional arrangement of the VCS is as described in the Design Description of this Section 2.7.7.	Inspection of the as-built system will be performed.	The as-built VCS conforms with the functional arrangement described in the Design Description of this Section 2.7.7.
2. Displays of the parameters identified in Table 2.7.7-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the parameters in the MCR.	The displays identified in Table 2.7.7-1 are retrieved in the MCR.

Table 2.7.7-3		
Component Name	**Tag No.**	**Component Location**
Reactor Containment Recirculation Fan Coil Unit Assembly A	VCS-MS-01A	Containment
Reactor Containment Recirculation Fan Coil Unit Assembly B	VCS-MS-01B	Containment

2.7.8 Radwaste Building HVAC System

The radwaste building HVAC system (VRS) serves the radwaste building and provides radiation monitoring of exhaust prior to release to the environment.

2.7.9 Turbine Island Building Ventilation System

No entry for this system.

2.7.10 Health Physics and Hot Machine Shop HVAC System

The health physics and hot machine shop system (VHS) serves the health physics and hot machine shop area of the annex building and provides radiation monitoring of exhaust prior to release to the environment.

2.7.11 Hot Water Heating System

No entry for this system.

3.1 Emergency Response Facilities

Design Description

The technical support center (TSC) is a facility from which management and technical support is provided to main control room (MCR) personnel during emergency conditions. The operations support center (OSC) provides an assembly area where operations support personnel report in an emergency.

1. The TSC has floor space of at least 75 ft^2 per person for a minimum of 25 persons.

2. The TSC has voice communication equipment for communication with the MCR, emergency operations facility, OSC, and the U.S. Nuclear Regulatory Commission (NRC).

3. The plant parameters listed in Table 2.5.4-1, minimum inventory table, in subsection 2.5.4, Data Display and Processing System (DDS), with a "Yes" in the "Display" column, can be retrieved in the TSC.

4. The OSC has voice communication equipment for communication with the MCR and TSC.

5. The TSC and OSC are in different locations in the annex building. The TSC is adjacent to the passage from the annex building to the nuclear island control room.

6. The TSC provides a habitable workspace environment.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 3.1-1 specifies the inspections, tests, analyses, and associated acceptance criteria for the emergency response facilities.

Table 3.1-1
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The TSC has floor space of at least 75 ft^2 per person for a minimum of 25 persons.	An inspection will be performed of the TSC floor space.	The TSC has at least 1875 ft^2 of floor space.
2. The TSC has voice communication equipment for communication with the MCR, emergency operations facility, OSC, and the NRC.	An inspection and test will be performed of the TSC voice communication equipment.	Communications equipment is installed, and voice transmission and reception are accomplished.
3. The plant parameters listed in Table 2.5.4-1, minimum inventory table, in subsection 2.5.4, DDS, with a "Yes" in the "Display" column, can be retrieved in the TSC.	An inspection will be performed for retrievability of the plant parameters in the TSC.	The plant parameters listed in Table 2.5.4-1, minimum inventory table, in subsection 2.5.4, DDS, with a "Yes" in the "Display" column, can be retrieved in the TSC.
4. The OSC has voice communication equipment for communication with the MCR and TSC.	Inspection will be performed of the OSC voice communication equipment.	Communications equipment is installed, and voice transmission and reception are accomplished.
5. The TSC and OSC are in different locations in the annex building. The TSC is adjacent to the passage from the annex building to the nuclear island control room.	An inspection will be performed of the location of the TSC and OSC.	The TSC and OSC are in different locations in the annex building. The TSC is adjacent to the passage from the annex building to the nuclear island control room.
6. The TSC provides a habitable workspace environment.	See Tier 1 Material, Table 2.7.1-4, items 1, 8a), 8c), 12, and 13, Nuclear Island Nonradioactive Ventilation System.	See Tier 1 Material, Table 2.7.1-4, items 1, 8a), 8c), 12, and 13, Nuclear Island Nonradioactive Ventilation System.

3.2 Human Factors Engineering

Design Description

The AP1000 human-system interface (HSI) will be developed and implemented based upon a human factors engineering (HFE) program. Figure 3.2-1 illustrates the HFE program elements. The HSI scope includes the design of the operation and control centers system (OCS) and each of the HSI resources. For the purposes of the HFE program, the OCS includes the main control room (MCR), the remote shutdown workstation (RSW), the local control stations, and the associated workstations for each of these centers. The HSI resources include the wall panel information system, alarm system, plant information system (nonsafety-related displays), qualified data processing system (safety-related displays), and soft and dedicated controls. Minimum inventories of controls, displays, and visual alerts are specified as part of the HSI for the MCR and the RSW.

The MCR provides a facility and resources for the safe control and operation of the plant. The MCR includes a minimum inventory of displays, visual alerts and fixed-position controls. Refer to item 8.a and Table 2.5.2-5 of subsection 2.5.2 for this minimum inventory.

The remote shutdown room (RSR) provides a facility and resources to establish and maintain safe shutdown conditions for the plant from a location outside of the MCR. The RSW includes a minimum inventory of displays, controls, and visual alerts. Refer to item 2 and Table 2.5.4-1 of subsection 2.5.4 for this minimum inventory. As stated in item 8.b of subsection 2.5.2, the protection and safety monitoring system (PMS) provides for the transfer of control capability from the MCR to the RSW.

The mission of local control stations is to provide the resources, outside of the MCR, for operations personnel to perform monitoring and control activities.

Implementation of the HFE program includes activities 1 through 5 listed below. The MCR includes design features specified by items 6 through 8 below. The RSW includes the design features specified by items 9 through 12 below. Local control stations include the design feature of item 13.

1. The integration of human reliability analysis with HFE design is performed in accordance with the implementation plan. Critical human actions (if any) and risk-important tasks are identified and used as an input to the task analysis activities.

2. Task analysis is performed in accordance with the task analysis implementation plan. Task analysis identifies the information and control requirements for the operators to execute the tasks allocated to them.

3. The HSI design is performed for the OCS in accordance with the HSI design implementation plan. The HSI design includes the functional design of the operation and control centers and the HSI resources, the specification of design guidelines, and the HSI resource design specifications.

4. An HFE program verification and validation implementation plan is developed in accordance with the programmatic level description of the AP1000 human factors verification and validation plan. The implementation plan establishes methods for conducting evaluations of the HSI design.

5. The HFE verification and validation program is performed in accordance with the HFE verification and validation implementation plan and includes the following activities:

   a) HSI Task support verification
   b) HFE design verification
   c) Integrated system validation
   d) Issue resolution verification
   e) Plant HFE/HSI (as designed at the time of plant startup) verification

6. The MCR includes reactor operator workstations, supervisor workstation(s), safety-related displays, and safety-related controls.

7. The MCR provides a suitable workspace environment for use by MCR operators.

8. The HSI resources available to the MCR operators include the alarm system, plant information system (nonsafety-related displays), wall panel information system, and nonsafety-related controls (soft and dedicated).

9. The RSW includes reactor operator workstation(s) from which licensed operators perform remote shutdown operations.

10. The RSR provides a suitable workspace environment, separate from the MCR, for use by the RSW operators.

11. The HSI resources available at the RSW include the alarm system displays, the plant information system, and the controls.

12. The RSW and the available HSI permit execution of tasks by licensed operators to establish and maintain safe shutdown.

13. The capability to access displays and controls is provided (controls as assigned by the MCR operators) for local control and monitoring from selected locations throughout the plant.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 3.2-1 specifies the inspections, tests, analyses, and associated acceptance criteria for the HFE program, MCR, RSW, and local control stations.

Table 3.2-1
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The integration of human reliability analysis with HFE design is performed in accordance with the implementation plan.	An evaluation of the implementation for the integration of human reliability analysis with HFE design will be performed.	A report exists and concludes that critical human actions (if any) and risk important tasks were identified and examined by task analysis, and used as input to the HSI design, procedure development, staffing, and training.
2. Task analysis is performed in accordance with the task analysis implementation plan.	An evaluation of the implementation of the task analysis will be performed.	– A report exists and concludes that function-based task analyses were conducted in conformance with the task analysis implementation plan and include the following functions: – Control reactivity – Control reactor coolant system (RCS) boron concentration – Control fuel and cladding temperature – Control RCS coolant temperature, pressure, and inventory – Provide RCS flow – Control main steam pressure – Control steam generator inventory – Control containment pressure and temperature Provide control of main turbineA report exists and concludes that operational sequence analyses (OSAs) were conducted in conformance with the task analysis implementation plan. OSAs performed include the following: – Plant heatup and startup from post-refueling to 100% power – Reactor trip, turbine trip, and safety injection

Table 3.2-1 Inspections, Tests, Analyses, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
		– Natural circulation cooldown (startup feedwater with steam generator) – Loss of reactor or secondary coolant – Post-loss-of-coolant accident (LOCA) cooldown and depressurization – Loss of RCS inventory during shutdown – Loss of the normal residual heat removal system (RNS) during shutdown – Manual automatic depressurization system (ADS) actuation – Manual reactor trip via PMS, via diverse actuation system (DAS) – ADS valve testing during mode 1

Table 3.2-1 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3. The HSI design is performed for the OCS in accordance with the HSI design implementation plan.	An evaluation of the implementation of the HSI design will be performed.	A report exists and concludes that the HSI design for the OCS was conducted in conformance with the implementation plan and includes the following documents: – Operation and Control Centers System Specification Document – Functional requirements and design basis documents for the alarm system, plant information system, wall panel information system, controls (soft and dedicated), and the qualified data processing subsystems – Design guideline documents (based on accepted HFE guidelines, standards, and principles) for the alarm system, displays, controls, and anthropometrics – Design specifications for the alarm system, plant information system, wall panel information system, controls (soft and dedicated), and the qualified data processing subsystems. – Engineering test report document summarizing outcomes of each man-in-the-loop engineering test iteration performed to support HSI design.

Table 3.2-1 (cont.) Inspections, Tests, Analyses, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
4. An HFE program verification and validation implementation plan is developed in accordance with the programmatic level description of the AP1000 human factors verification and validation plan.	An inspection of the HFE verification and validation implementation plan will be performed.	A report exists and concludes that the HFE verification and validation implementation plan was developed in accordance with the programmatic level description of the AP1000 human factors verification and validation plan and includes the following activities: – HSI task support verification – HFE design verification – Integrated system validation – Issue resolution verification – Plant HFE/HSI (as designed at the time of plant startup) verification
5. The HFE verification and validation program is performed in accordance with the HFE verification and validation implementation plan and includes the following activities:		
a) HSI Task support verification	a) An evaluation of the implementation of the HSI task support verification will be performed.	a) A report exists and concludes that: Task support verification was conducted in conformance with the implementation plan and includes verification that the information and controls provided by the HSI match the display and control requirements generated by the function-based task analyses and the operational sequence analyses.
b) HFE design verification	b) An evaluation of the implementation of the HFE design verification will be performed.	b) A report exists and concludes that: HFE design verification was conducted in conformance with the implementation plan and includes verification that the HSI design is consistent with the AP1000 specific design guidelines (compiled as specified in the third acceptance criteria of design commitment 3) developed for each HSI resource.

Table 3.2-1 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
c) Integrated system validation	c) (i) An evaluation of the implementation of the integrated system validation will be performed.	c) (i) A report exists and concludes that: The test scenarios listed in the implementation plan for integrated system validation were executed in conformance with the plan and noted human deficiencies were addressed.
	c) (ii) Tests and analyses of the following plant evolutions and transients, using a facility that physically represents the MCR configuration and dynamically represents the MCR HSI and the operating characteristics and responses of the AP1000 design, will be performed: – Normal plant heatup and startup to 100% power – Normal plant shutdown and cooldown to cold shutdown – Transients: reactor trip and turbine trip – Accidents: - Small-break LOCA - Large-break LOCA - Steam line break - Feedwater line break - Steam generator tube rupture	c) (ii) A report exists and concludes that: The test and analysis results demonstrate that the MCR operators can perform the following: – Heat up and start up the plant to 100% power – Shut down and cool down the plant to cold shutdown – Bring the plant to safe shutdown following the specified transients – Bring the plant to a safe, stable state following the specified accidents
d) Issue resolution verification	d) An evaluation of the implementation of the HFE design issue resolution verification will be performed.	d) A report exists and concludes that: HFE design issue resolution verification was conducted in conformance with the implementation plan and includes verification that human factors issues documented in the design issues tracking system have been addressed in the final design.

Table 3.2-1 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
e) Plant HFE/HSI (as designed at the time of plant startup) verification	e) An evaluation of the implementation of the plant HFE/HSI (as designed at the time of plant startup) verification will be performed.	e) A report exists and concludes that: The plant HFE/HSI, as designed at the time of plant startup, is consistent with the HFE/HSI verified in 5.a) through 5.d).
6. The MCR includes reactor operator workstations, supervisor workstation(s), safety-related displays, and safety-related controls.	An inspection of the MCR workstations and control panels will be performed.	The MCR includes reactor operator workstations, supervisor workstation(s), safety-related displays, and safety-related controls.
7. The MCR provides a suitable workspace environment for use by the MCR operators.	i) See Tier 1 Material, subsection 2.7.1, Nuclear Island Nonradioactive Ventilation System. ii) See Tier 1 Material, subsection 2.2.5, MCR Emergency Habitability System. iii) See Tier 1 Material, subsection 2.6.3, Class 1E dc and UPS System. iv) See Tier 1 Material, subsection 2.6.5, Lighting System. v) See Tier 1 Material, subsection 2.3.19, Communication System.	i) See Tier 1 Material, subsection 2.7.1, Nuclear Island Nonradioactive Ventilation System. ii) See Tier 1 Material, subsection 2.2.5, MCR Emergency Habitability System. iii) See Tier 1 Material, subsection 2.6.3, Class 1E dc and UPS system. iv) See Tier 1 Material, subsection 2.6.5, Lighting System. v) See Tier 1 Material, subsection 2.3.19, Communication System.
8. The HSI resources available to the MCR operators include the alarm system, plant information system (nonsafety-related displays), wall panel information system, and nonsafety-related controls (soft and dedicated).	An inspection of the HSI resources available in the MCR for the MCR operators will be performed.	The HSI (at the time of plant startup) includes an alarm system, plant information system (nonsafety-related displays), wall panel information system, and nonsafety-related controls (soft and dedicated).
9. The RSW includes reactor operator workstation(s) from which licensed operators perform remote shutdown operations.	An inspection of the RSW will be performed.	The RSW includes reactor operator workstation(s).

Table 3.2-1 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
10. The RSR provides a suitable workspace environment, separate from the MCR, for use by the RSW operators.	i) See Tier 1 Material, subsection 2.7.1, Nuclear Island Nonradioactive Ventilation System. ii) See Tier 1 Material, subsection 2.6.5, Lighting System. iii) See Tier 1 Material, subsection 2.3.19, Communication System.	i) See Tier 1 Material, subsection 2.7.1, Nuclear Island Nonradioactive Ventilation System. ii) See Tier 1 Material, subsection 2.6.5, Lighting System. iii) See Tier 1 Material, subsection 2.3.19, Communication System.
11. The HSI resources available at the RSW include the alarm system displays, the plant information system, and the controls.	An inspection of the HSI resources available at the RSW will be performed.	The as-built HSI at the RSW includes the alarm system displays, the plant information system, and the controls.
12. The RSW and the available HSI permit execution of tasks by licensed operators to establish and maintain safe shutdown.	Test and analysis, using a workstation that physically represents the RSW and dynamically represents the RSW HSI and the operating characteristics and responses of the AP1000, will be performed.	A report exists and concludes that the test and analysis results demonstrate that licensed operators can achieve and maintain safe shutdown conditions from the RSW.
13. The capability to access displays and controls is provided (controls as assigned by the MCR operators) for local control and monitoring from selected locations throughout the plant.	An inspection of the local control and monitoring capability is provided.	The capability for local control and monitoring from selected locations throughout the plant exists.

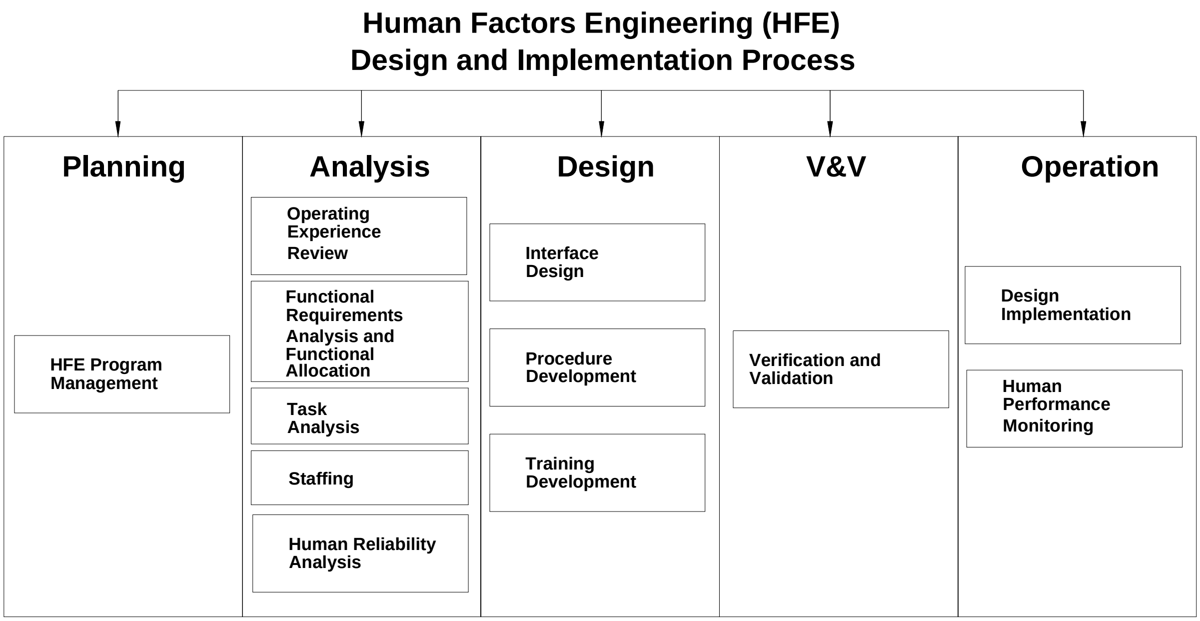


Figure 3.2-1
Human Factors Engineering (HFE)
Design and Implementation Process

3.3 Buildings

Design Description

The nuclear island structures include the containment (the steel containment vessel and the containment internal structure) and the shield and auxiliary buildings. The containment, shield and auxiliary buildings are structurally integrated on a common basemat which is embedded below the finished plant grade level. The containment vessel is a cylindrical welded steel vessel with elliptical upper and lower heads, supported by embedding a lower segment between the containment internal structures concrete and the basemat concrete. The containment internal structure is reinforced concrete with structural modules used for some walls and floors. The shield building is reinforced concrete and, in conjunction with the internal structures of the containment building, provides shielding for the reactor coolant system and the other radioactive systems and components housed in the containment. The shield building roof is a reinforced concrete structure containing an integral, steel lined passive containment cooling water storage tank. The auxiliary building is reinforced concrete and houses the safety-related mechanical and electrical equipment located outside the containment and shield buildings.

The portion of the annex building adjacent to the nuclear island is a structural steel and reinforced concrete seismic Category II structure and houses the technical support center, non-1E electrical equipment, and hot machine shop.

The radwaste building is a steel framed structure and houses the low level waste processing and storage.

The turbine building is a non-safety related structure that houses the main turbine generator and the power conversion cycle equipment and auxiliaries. There is no safety-related equipment in the turbine building. The turbine building is located on a separate foundation. The turbine building structure is adjacent to the nuclear island structures.

The diesel generator building is a non-safety related structure that houses the two standby diesel engine powered generators and the power conversion cycle equipment and auxiliaries. There is no safety-related equipment in the diesel generator building. The diesel generator building is located on a separate foundation at a distance from the nuclear island structures.

The plant gas system (PGS) provides hydrogen, carbon dioxide, and nitrogen gases to the plant systems as required. The component locations of the PGS are located either in the turbine building or the yard areas.

1. The physical arrangement of the nuclear island structures and the annex building is as described in the Design Description of this Section 3.3, and as shown on Figures 3.3-1 through 3.3-14. The physical arrangement of the radwaste building, the turbine building, and the diesel generator building is as described in the Design Description of this Section 3.3.

2. a) The nuclear island structures, including the critical sections listed in Table 3.3-7, are seismic Category I and are designed and constructed to withstand design basis loads, as specified in the Design Description, without loss of structural integrity and the safety-related functions. The design bases loads are those loads associated with:

   - Normal plant operation (including dead loads, live loads, lateral earth pressure loads, and equipment loads, including hydrodynamic loads, temperature and equipment vibration);

- External events (including rain, snow, flood, tornado, tornado generated missiles and earthquake); and

- Internal events (including flood, pipe rupture, equipment failure, and equipment failure generated missiles).

b) Site grade level is located relative to floor elevation 100′-0″ per Table 3.3-5. Floor elevation 100′-0″ is defined as the elevation of the floor at design plant grade.

c) The containment and its penetrations are designed and constructed to ASME Code Section III, Class MC.[(1)]

d) The containment and its penetrations retain their pressure boundary integrity associated with the design pressure.

e) The containment and its penetrations maintain the containment leakage rate less than the maximum allowable leakage rate associated with the peak containment pressure for the design basis accident.

f) The key dimensions of the nuclear island structures are as defined on Table 3.3-5.

g) The containment vessel greater than 7 feet above the operating deck provides a heat transfer surface. A free volume exists inside the containment shell above the operating deck.

h) The containment free volume below elevation 108′ provides containment floodup during a postulated loss-of-coolant accident.

3. Walls and floors of the nuclear island structures as defined on Table 3.3-1, except for designed openings and penetrations, provide shielding during normal operations.

4. a) Walls and floors of the annex building as defined on Table 3.3-1, except for designed openings and penetrations, provide shielding during normal operations.

   b) The walls on the outside of the waste accumulation room in the radwaste building provide shielding from accumulated waste.

   c) The walls on the outside of the packaged waste storage room in the radwaste building provide shielding from stored waste.

5. a) Exterior walls and the basemat of the nuclear island have a water barrier up to site grade.

   b) The boundaries between mechanical equipment rooms and the electrical and instrumentation and control (I&C) equipment rooms of the auxiliary building as identified in Table 3.3-2 are designed to prevent flooding of rooms that contain safety-related equipment up to the maximum flood level for each room defined in Table 3.3-2.

1. Containment isolation devices are addressed in subsection 2.2.1, Containment System.

c) The boundaries between the following rooms, which contain safety-related equipment – passive core cooling system (PXS) valve/accumulator room A (11205), PXS valve/accumulator room B (11207), and chemical and volume system (CVS) room (11209) – are designed to prevent flooding between these rooms.

6. a) The radiologically controlled area of the auxiliary building between floor elevations 66′-6″ and 82′-6″ contains adequate volume to contain the liquid volume of faulted liquid radwaste system (WLS) storage tanks. The available room volumes of the radiologically controlled area of the auxiliary building between floor elevations 66′-6″ and 82′-6″ exceeds the volume of the liquid radwaste storage tanks (WLS-MT-05A, MT-05B, MT-06A, MT-06B, MT-07A, MT-07B, MT-07C, MT-11).

   b) The radwaste building packaged waste storage room has a volume greater than or equal to 1293 cubic feet.

7. a) Class 1E electrical cables, fiber optic cables associated with only one division, and raceways are identified according to applicable color-coded Class 1E divisions.

   b) Class 1E divisional electrical cables and communication cables associated with only one division are routed in their respective divisional raceways.

   c) Separation is maintained between Class 1E divisions in accordance with the fire areas as identified in Table 3.3-3.

   d) Physical separation is maintained between Class 1E divisions and between Class 1E divisions and non-Class 1E cables.

   e) Class 1E communication cables which interconnect two divisions are routed and separated such that the Protection and Safety Monitoring System voting logic is not defeated by the loss of any single raceway or fire area.

8. Equipment labeled as essential targets in Table 3.3-4 and located in rooms identified in Table 3.3-4 are protected from the dynamic effects of postulated pipe breaks.

9. The reactor cavity sump has a minimum concrete thickness as shown on Table 3.3-5 between the bottom of the sump and the steel containment.

10. The shield building roof and the passive containment cooling system (PCS) storage tank support and retain the PCS water. The passive containment cooling system tank has a stainless steel liner which provides a barrier on the inside surfaces of the tank. Leak chase channels are provided over the tank boundary liner welds.

11. Deleted

12. The extended turbine generator axis intersects the shield building.

13. Separation is provided between the structural elements of the turbine, annex, and radwaste buildings and the nuclear island structure. This separation permits horizontal motion of the buildings in a safe shutdown earthquake without impact between structural elements of the buildings.

14. The walls, doors, ceiling, and floors in the main control room, central alarm station, and secondary alarm station are bullet-resistant to a level 4 round.

15. Central alarm station and main control room are vital areas.

16. Security power supply system for alarm annunciator equipment and non-portable communications equipment is located within a vital area.

17. Vital areas are locked and alarmed with active intrusion detection systems that annunciate in the central and secondary alarm stations upon intrusion into a vital area.

18. The locks used for the protection of the vital areas are manipulative-resistant.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 3.3-6 specifies the inspections, tests, analyses, and associated acceptance criteria for the buildings.

Table 3.3-1
Definition of Wall Thicknesses for Nuclear Island Buildings and Annex Building[1]

Wall or Section Description	Column Lines	Floor Elevation or Elevation Range	Concrete Thickness(2)(3)(4)(5)	Applicable Radiation Shielding Wall (Yes/No)
Containment Building Internal Structure				
Shield Wall between Reactor Vessel Cavity and RCDT Room	E-W wall parallel with column line 7	From 71'-6" to 83'-0"	3'-0"	Yes
West Reactor Vessel Cavity Wall	N-S wall parallel with column line N	From 83'-0" to 98'-0"	7'-6"	Yes
North Reactor Vessel Cavity Wall	E-W wall parallel with column line 7	From 83'-0" to 98'-0"	9'-0"	Yes
East Reactor Vessel Cavity Wall	N-S wall parallel with column line N	From 83'-0" to 98'-0"	7'-6"	Yes
West Refueling Cavity Wall	N-S wall parallel with column line N	From 98'-0" to 135'-3"	4'-0"	Yes
North Refueling Cavity Wall	E-W wall parallel with column line 7	From 98'-0" to 135'-3"	4'-0"	Yes
East Refueling Cavity Wall	N-S wall parallel with column line N	From 98'-0" to 135'-3"	4'-0"	Yes
South Refueling Cavity Wall	E-W wall parallel with column line 7	From 98'-0" to 135'-3"	4'-0"	Yes
South wall of west steam generator compartment	Not Applicable	From 103'-0" to 153'-0"	2'-6"	Yes
West wall of west steam generator compartment	Not Applicable	From 103'-0" to 153'-0"	2'-6"	Yes
North wall of west steam generator compartment/south wall of pressurizer compartment	Not Applicable	From 103'-0" to 153'-0"	2'-6"	Yes
West wall of pressurizer compartment	Not Applicable	From 107'-2" to 169'-0"	2'-6"	Yes
North wall of pressurizer compartment	Not Applicable	From 107'-2" to 169'-0"	2'-6"	Yes
East wall of pressurizer compartment	Not Applicable	From 118'-6" to 169'-0"	2'-6"	Yes
North-east wall of in-containment refueling water storage tank	Parallel to column line N	From 103'-0" to 135'-3"	2'-6"	No
West wall of in-containment refueling water storage tank	Not applicable	From 103'-0" to 135'-3"	5/8" steel plate with stiffeners	No
South wall of east steam generator compartment	Not Applicable	From 87'-6" to 153'-0"	2'-6"	Yes

1. The column lines and floor elevations are identified and included on Figures 3.3-1 through 3.3-13.
2. These wall (and floor) thicknesses have a construction tolerance of ± 1 inch, except for exterior walls below grade where the tolerance is +12 inches, - 1 inch.
3. For walls that are part of structural modules, the concrete thickness also includes the steel face plates.
4. For floors with steel surface plates, the concrete thickness also includes the plate thickness.
5. Where a wall (or a floor) has openings, the concrete thickness does not apply at the opening.

Table 3.3-1 (cont.)
Definition of Wall Thicknesses for Nuclear Island Buildings and Annex Building(1)

Wall or Section Description	Column Lines	Floor Elevation or Elevation Range	Concrete Thickness(2)(3)	Applicable Radiation Shielding Wall (Yes/No)
East wall of east steam generator compartment	Not Applicable	From 94'-0" to 153'-0"	2'-6"	Yes
North wall of east steam generator compartment	Not Applicable	From 87'-6" to 153'-0"	2'-6"	Yes
Shield Building				
Shield Building Cylinder	Not Applicable	From 100'-0" to 265’-0″	3'-0"	Yes
Columns between air inlets	Not Applicable	From 265’-0″ to 271’-6″	3'-0"	Yes
Tension Ring	Not Applicable	From 271’-6″ to 275’-10″	3'-0"	Yes
Conical Roof	Not Applicable	From 275’-10″ to 289'-0"	1'-6" cast-in-place concrete over 6" pre-cast concrete ribbed conical sections	Yes
PCS Tank External Cylindrical Wall	Not Applicable	From 298’-9″ to 333’-9″	2'-0"	Yes
PCS Tank Internal Cylindrical Wall	Not Applicable	From 314’-4″ to 334’-0″	1'-6"	Yes
PCS Tank Roof	Not Applicable	334’-0″	1'-3"	No
Auxiliary Building Walls/Floors				
Column Line 1 wall	From I to N	From 66'-6" to 100'-0"	3'-0"	No
Column Line 1 wall	From I to 5'-6" east of L-2	From 100'-0" to 180'-0"	2'-3"	Yes
Column Line 1 wall	From 5'-6" east of L-2 to N	From 100'-0" to 125'-0"	3'-0"	Yes
Column Line 1 wall	From 5'-6" east of L-2 to N	From 125'-0" to 180'-0"	2'-3"	Yes
Column Line 2 wall	From I to K-2	From 66'-6" to 135'-3"	2'-6"	Yes
Column Line 2 wall	From K-2 to L-2	From 66'-6" to 135'-3"	5'-0"	Yes
Column Line 2 wall	From L-2 to N	From 98'-1" to 135'-3"	2'-6"	Yes
Column Line 2 wall	From I to J-1	From 135'-3" to 153'-0"	2'-0"	Yes
Column Line 3 wall	From J-1 to J-2	From 66'-6" to 82'-6"	2'-6"	Yes
Column Line 3 wall	From J-1 to J-2	From 100'-0" to 135'-3"	2'-6"	Yes
Column Line 3 wall	From J-2 to K-2	From 66'-6" to 135'-3"	2'-6"	Yes

Table 3.3-1 (cont.)
Definition of Wall Thicknesses for Nuclear Island Buildings and Annex Building(1)

Wall or Section Description	Column Lines	Floor Elevation or Elevation Range	Concrete Thickness(2)(3)	Applicable Radiation Shielding Wall (Yes/No)
Column Line 3 wall	From K-2 to L-2	From 66'-6" to 92'-8 1/2"	2'-6"	Yes
Column Line 4 wall	From I to J-1	From 66'-6" to 153'-0"	2'-6"	Yes
Column Line 4 wall	From J-1 to J-2	From 66'-6" to 92'-6"	2'-6"	Yes
Column Line 4 wall	From J-1 to J-2	From 107'-2" to 135'-3"	2'-6"	Yes
Column Line 4 wall	From J-2 to K-2	From 66'-6" to 135'-3"	2'-6"	Yes
Column Line 4 wall	From I to intersection with shield building wall	From 135'-3" to 180'-0"	2'-0"	Yes
Column Line 5 wall	From I to shield building; with opening east of J-1 (below 107'-2" floor).	From 66'-6" to 160'-6"	2'-0"	Yes
Column Line 7.1 wall	From I to 8' east of J-1	From 66'-6" to 82'-6"	2'-0"	Yes
Column Line 7.2 wall	From I to 5'-6"east of J-1	From 66'-6" to 100'-0"	2'-0"	Yes
Column Line 7.3 wall	From I to shield building	From 66'-6" to 100'-0"	3'-0"	Yes
Column Line 7.3 wall	From I to shield building	From 100'-0" to 160'-6"	2'-0"	No
Column Line 11 wall	From I to Q	From 66'-6" to 100'-0"	3'-0"	No
Column Line 11 wall	From I to Q	From 100'-0" to 117'-6"	2'-0"	Yes
Column Line 11 wall	From I to L	From 117'-6" to 153'-0"	2'-0"	Yes
Column Line 11 wall	From L to M	From 117'-6" to 135'-3"	4'-0"	Yes
Column Line 11 wall	From M to P	From 117'-6" to 135'-3"	2'-0"	Yes
Column Line 11 wall	From P to Q	From 117'-6" to 135'-3"	4'-0"	Yes
Column Line 11 wall	From L to Q	From 135'-3" to 153'-0"	2'-0"	Yes
Column Line I wall	From 1 to 11	From 66'-6" to 100'-0"	3'-0"	No
Column Line I wall	From 1 to 4	From 100'-0" to 180'-0"	2'-0"	Yes
Column Line I wall	From 4 to 7.3	From 100'-0" to 160'-6"	2'-0"	No
Column Line I wall	From 7.3 to 11	From 100'-0" to 153'-0"	2'-0"	No
Column Line J-1 wall	From 1 to 2	From 82'-6" to 100'-0"	2'-0"	Yes
Column Line J-1 wall	From 2 to 4	From 66'-6" to 135'-3"	2'-6"	Yes

Table 3.3-1 (cont.)
Definition of Wall Thicknesses for Nuclear Island Buildings and Annex Building[1]

Wall or Section Description	Column Lines	Floor Elevation or Elevation Range	Concrete Thickness[2][3]	Applicable Radiation Shielding Wall (Yes/No)
Column Line J-1 wall	From 2 to 4	From 135'-3" to 153'-0"	2'-0"	Yes
Column Line J-1 wall	From 4 to shield building	From 66'-6" to 107'-2"	2'-0"	Yes
Column Line J-2 wall	From 2 to 4	From 66'-6" to 135'-3"	2'-6"	Yes
Column Line J-2 wall	From 4 to intersection with shield building wall	From 66'-6" to 135'-3"	2'-0"	Yes
Column Line K-2 wall	From 2 to 4	From 66'-6" to 135'-3"	4'-9"	Yes
Column Line L-2 wall	From 2 to 4	From 66'-6" to 135'-3"	4'-0"	Yes
Column Line N wall	From 1 to 2	From 66'-6" to 100'-0"	3'-0"	No
Column Line N wall	From 1 to 12'-9" north of 1	From 100'-0" to 125'-0"	3'-9"	No
Column Line N wall	From 1 to 12'-9" north of 1	From 125'-0" to 135'-0"	2'-0"	No
Column Line N wall	From 12'-9" north of 1 to 2	From 100'-0" to 118'-2 1/2"	3'-0"	No
Column Line N wall	From 12'-9" north of 1 to 2	From 118'-2 1/2" to 135'-3"	2'-0"	No
Column Line N wall	From 1 to 2	From 118'-2 1/2" to 135'-3"	2'-0"	Yes
Column Line N wall	From 2 to 4	From 66'-6" to 98'-1"	3'-0"	No
Column Line N wall	From 2 to 4	From 98'-1" to 135'-3"	5'-6"	Yes
Column Line N wall	From 1 to 4	From 135'-3" to 180'-0"	2'-0"	Yes
Column Line J wall	From 7.3 to 11	From 66'-6" to 117'-6"	2'-0"	No
Column Line K wall	From 7.3 to 11	From 60'-6" to 135'-3"	2'-0"	Yes
Column Line L wall	From shield building wall to 11	From 60'-6" to 153'-0"	2'-0"	Yes
Column Line M wall	From shield building wall to 11	From 66'-6" to 153'-0"	2'-0"	Yes
Column Line P wall	From shield building wall to 11	From 66'-6" to 153'-0"	2'-0"	Yes
Column Line Q wall	From shield building wall to 11	From 66'-6" to 100'-0"	3'-0"	No
Column Line Q wall	From shield building wall to 11	From 100'-0" to 153'-0"	2'-0"	Yes
Labyrinth Wall between Col. Line 3 and 4 and J-1 to 7'-3" from J-2	Not Applicable	From 82'-6" to 92'-6"	2'-6"	Yes
N-S Shield Wall (low wall)	Between K-2 and L-2 extending from column line 1 north	From 100'-0" to 107'-2"	2'-6"	Yes

Table 3.3-1 (cont.)
Definition of Wall Thicknesses for Nuclear Island Buildings and Annex Building(1)

Wall or Section Description	Column Lines	Floor Elevation or Elevation Range	Concrete Thickness(2)(3)	Applicable Radiation Shielding Wall (Yes/No)
N-S Shield Wall	Between K-2 and L-2 extending from column line 1 north	From 100'-0" to 125'-0"	2'-3"	Yes
E-W Shield Wall	Between 1 and 2 extending from column line N east	From 100'-0" to 125'-0"	2'-9"	Yes
Column Line 9.2 wall	From I to J and K to L	From 117'-6" to 135'-3"	2'-0"	Yes
Labyrinth Wall between Column Line 7.3 and 9.2 and J to K	J to K	From 117'-6" to 135'-3"	2'-0"	Yes
Auxiliary Area Basemat	From 1-11 and I-Q, excluding shield building	From 60'-6" to 66'-6"	6'-0"	No
Nuclear Island Basemat	Below shield building	From 60'-6" to containment vessel or 82'-6"	6'-0" to 22'-0" (varies)	No
Floor	From 1 to 2 and I to N	82'-6"	2'-0"	Yes
Floor	From 2 to 4 and J-1 to J-2	82'-6"	2'-0"	Yes
Floor	From 4 to 5 and J-1 to J-2	82'-6"	0'-9"	Yes
Pipe Chase Floor	From 2 to 5 and J-1 to J-2	92'-6"	2'-0"	Yes
Floor	From 2 to 3 and J-2 to K-2	90'-3"	3'-0"	Yes
Floor	From 3 to 4 and J-2 to K-2	92'-6"	2'-0"	Yes
Floor	From 4 to 7.3 and I to J-1	82'-6"	2'-0"	Yes
Floor	From 1 to 2 and I to N	100'-0"	3'-0"	Yes
Floor	From 2 to 4 and K-2 to L-2	92'-8 1/2"	3'-2 1/2"	Yes
Floor	From I to J-2 and 4 to intersecting vertical wall before column line 5	107'-2"	2'-0"	Yes
Floor	From I to shield building wall and from intersecting vertical wall before column line 5 to column line 5	105'-0"	0'-9"	Yes
Floor	From 5 to 7.3 and I to shield building wall	100'-0"	2'-0"	Yes
Floor	From K to L and shield building wall to column line 10	100'-0"	0'-9"	Yes

Table 3.3-1 (cont.)
Definition of Wall Thicknesses for Nuclear Island Buildings and Annex Building(1)

Wall or Section Description	Column Lines	Floor Elevation or Elevation Range	Concrete Thickness(2)(3)	Applicable Radiation Shielding Wall (Yes/No)
Floor	From 1 to 10'-0" north of 1 and L-2 to N	125'-0"	3'-0"	Yes
Floor	From 10'-0" north of 1 to 2 and L-2 to N	118'-2 1/2"	2'-0"	Yes
Main Control Room Floor	From 9.2 to 11 and I to L	117'-6"	2'-0"	Yes
Floor	Bounded by shield bldg, 7.3, J, 9.2 and L	117'-6"	2'-0"	Yes
Floor	From 9.2 to 11 and L to Q	117'-6"	2'-0"	Yes
Floor	From 3 to 4 and J-2 to K-2	117'-6"	2'-0"	Yes
Floor	From 2 to 4 and I to J-1	153'-0"	1'-1 1/2"	Yes
Floor	From 1 to 4 and I to N	180'-0"	1'-3"	Yes
Floor	From 4 to short of column line 5 and from I to intersection with shield building wall	135'-5"	0'-9"	Yes
Floor	From short of column line 5 to column line 5 and from I to intersection with shield building wall	133'-0"	0'-9"	Yes
Floor	From 5 to 7.3 and from I to intersection with shield building wall	135'-3"	0'-9"	Yes
Annex Building				
Column line 2 wall	From E to H	From 107'-2" to 135'-3"	19 3/4"	Yes
Column line 4 wall	From E to H	From 107'-2" to 162'-6" & 166'-0"	2'-0"	Yes
N-S Shield Wall between E and F	From 2 to 4	From 107'-2" to 135'-3"	1'-0"	Yes
Column line 4.1 wall	From E to H	From 107'-2" to 135'-3"	2'-0"	Yes
E-W Labyrinth Wall between column line 7.1 and 7.8 and G to H	Not Applicable	From 100'-0" to 112'-0"	2'-0"	
N-S Labyrinth Wall between column line 7.8 and 9 and G to H	Not Applicable	From 100'-0" to 112'-0"	2'-0"	

Table 3.3-1 (cont.)
Definition of Wall Thicknesses for Nuclear Island Buildings and Annex Building(1)

Wall or Section Description	Column Lines	Floor Elevation or Elevation Range	Concrete Thickness(2)(3)	Applicable Radiation Shielding Wall (Yes/No)
E-W Labyrinth Wall between column line 7.1 and 7.8 and G to H	Not Applicable	From 100'-0" to 112'-0"	2'-0"	Yes
N-S Shield Wall on Column line. F	From 4.1 North	From 100'-0" to 117'-6"	1'-0"	Yes
Column Line 9 wall	From E to connecting wall between G and H	From 107'-2" to 117'-6"	2'-0"	Yes
Column Line E wall	From 9 to 13	From 100'-0" to 135'-3"	2'-0"	Yes
Column Line 13 wall	From E to I.1	From 100'-0" to 135'-3"	2'-0"	Yes
Column Line I.1 wall	From 11.09 to 13	From 100'-0" to 135'-3"	2'-0"	Yes
Corridor Wall between G and H	From 9 to 13	From 100'-0" to 135'-3"	1'-6"	Yes
Column Line 9 wall	From I to H	From 117'-6" to 158'-0"	2'-0"	Yes
Floor	2 to 4 from shield wall between E and F to column line H	135'-3"	0'-6"	Yes
Floor	From 4 to 4.1 and E to H	135'-3"	1'-0"	Yes
Floor	From 9 to 13 and E to I.1	117'-6"	0'-6"	Yes
Floor	From 9 to 13 and E to I.1	135'-3"	0'-8"	Yes
Containment Filtration Rm A (North Wall)	Between column line E to H	From 135'-3" to 158'-0"	1'-0"	Yes
Containment Filtration Rm A (East wall)	Between column line E to F	From 135'-3" to 158'-0"	1'-0"	Yes
Containment Filtration Rm A (West wall)	Between column line G to H	From 135'-3" to 158'-0"	1'-0"	Yes
Containment Filtration Rm A (Floor)	Between column line E to H	135'-3"	1'-0"	Yes
Containment Filtration Rm B (Floor)	Between column line E to H	146'-3"	0'-6"	Yes
Containment Filtration Rm B (West wall)	Between column line G to H	From 146'-3" to 158'-0"	1'-0"	Yes

Table 3.3-2
Nuclear Island Building Room Boundaries
Required to Have Flood Barrier Floors and Walls

Boundary/ Maximum Flood Level (inches)	Between Room Number to Room Number	
	Room with Postulated Flooding Source	Adjacent Room
Floor/36	12306	12211
Floor/3	12303	12203/12207
Floor/3	12313	12203/12207
Floor/1	12300	12201/12202/12207 12203/12204/12205
Floor/3	12312	12212
Wall/36	12306	12305
Floor/1	12401	12301/12302/12303 12312/12313
Wall/1	12401	12411/12412
Floor/36	12404	12304
Floor/4	12405	12305
Floor/36	12406	12306
Wall/36	12404	12401
Wall/1	12421	12452
Floor/3	12501	12401/12411/12412
Floor/3	12555	12421/12423/12422
Wall/36	12156/12158	12111/12112

Table 3.3-3
Class 1E Divisions in Nuclear Island Fire Areas

Fire Area Number	Class 1E Divisions			
	A	C	B	D
1200 AF 01	Yes	Yes	–	–
1200 AF 03	–	–	Yes	Yes
1201 AF 02	–	–	Yes	–
1201 AF 03	–	–	–	Yes
1201 AF 04	–	–	Yes	Yes
1201 AF 05	–	–	Yes	Yes
1201 AF 06	–	–	Yes	Yes
1202 AF 03	–	Yes	–	–
1202 AF 04	Yes	–	–	–
1204 AF 01	Yes	–	–	–
1220 AF 01	–	–	Yes	Yes
1220 AF 02	–	–	–	Yes
1230 AF 01	Yes	Yes	–	–
1230 AF 02	–	–	Yes	Yes
1240 AF 01	Yes	Yes	–	–
1242 AF 02	Yes		–	

Note: Dash (–) indicates not applicable.

Table 3.3-4
Nuclear Island Rooms with Postulated High Energy Line Breaks/Essential Targets/Pipe Whip Restraints and Related Hazard Source

Room Number	Room Description	Essential Target Description	Hazard Source
11201	Steam Generator Compartment-01	Automatic depressurization system (ADS) Stage 4 valves (RCS-V004A, RCS-V004C, RCS-V014A, and RCS-V014C	1) Reactor Coolant System (RCS)-Pressurizer Spray Line, 4" L110A: Terminal End Break at RCS Cold Leg 1A 2) RCS-Pressurizer Spray Line, 4" L106: Terminal End Break at RCS Cold Leg 1B
11209	Pipe Chase to CVS Equipment Room	CVS makeup, CVS letdown, CVS hydrogen supply, and SGS steam generator blowdown piping	1) Steam Generator System (SGS)-Blowdown Line, 4" L009A: Terminal End Break at Containment Penetration P27 2) SGS-Blowdown Line, 4" L009B: Terminal End Break at Containment Penetration P28 3) CVS-Makeup Line, 3" L056: Terminal End Break at In-Line Anchor
11303	Lower Pressurizer Compartment	SGS steam generator blowdown and steam generator drain piping. RCS pressurizer pressure and level instrumentation; pressurizer support steel	1) RCS-CVS Purification Line, 3" L112: Intermediate Break at Outlet to Valve CVS-V082
11400	Maintenance Floor Mezzanine	Steam generator supports	1) SGS-Startup Feedwater Line, 6" L005B: Terminal End Break at Containment Penetration P45
11401	Steam Generator 01 Compartment	ADS Stage 4 valves (RCS-V004A, RCS-V004C, RCS-V014A, and RCS-V014C)	1) RCS Pressurizer Spray Line, 4" L106: Terminal End Break at In-Line Anchor
11403	Pressurizer Spray Valve Room	ADS Stage 4 valves (RCS-V004A, RCS-V004C, RCS-V014A, and RCS-V014C)	1) RCS Pressurizer Spray Line, 4" L213: Intermediate Break at 4x2 Tee Connection to Auxiliary Spray Line 2) RCS CVS Letdown Line, 3" L111: Intermediate Break at Inlet to Valve CVS-V001

**Table 3.3-4 (cont.)
Nuclear Island Rooms with Postulated High Energy Line Breaks/Essential Targets/Pipe Whip Restraints and Related Hazard Source**

Room Number	Room Description	Essential Target Description	Hazard Source
11503	Upper Pressurizer Compartment	ADS Stage 1, 2, and 3 valves, lower tier platform support steel	1) RCS-Pressurizer Spray Line, 4" L215: Terminal End Break at Pressurizer Nozzle
11601	Steam Generator-01 Feed Water Nozzle Area	RCS head vent piping SGS level instrumentation piping	1) SGS-Startup Feedwater Line, 6" L005A: Terminal End Break at Steam Generator Loop 1 Nozzle 2) SGS-Main Feedwater Line, 20" L003A: Terminal End Break at Steam Generator Loop 1 Nozzle
11602	Steam Generator-02 Feedwater Nozzle Area	SGS level instrumentation piping	1) SGS-Main Feedwater line, 20" L003B: Terminal End Break at Steam Generator Loop 2 Nozzle
11603	Lower ADS Valve Area	ADS Stage 2 and 3 valves (RCS-V002B, RCS-V003B, RCS-V012B, and RCS-V013B) Raceways and cable for Divisions A/C and B/D	1) RCS-Automatic Depressurization System Stage 1 Line, 4" L010B: Terminal End Break at Inlet to Valve RCS V011B
11703	Upper ADS Valve Area	ADS Stage 2 and 3 valves (RCS-V002A, RCS-V003A, RCS-V012A, and RCS-V013A) Raceways and cables for Division A/C	1) RCS-Automatic Depressurization System Stage 1 Line, 4" L010A: Terminal End Break at Inlet to Valve RCS V011A
12244	Lower Annulus Valve Area	CVS Makeup valve – CVS-V090	1) CVS-Makeup Line, 3" L131: Terminal End at In-Line Anchor

Table 3.3-5
Key Dimensions of Nuclear Island Building Features

Key Dimension	Reference Dimension (Figure 3.3-14)	Nominal Dimension	Tolerance
Distance between Outside Surface of walls at Column Line I & N when Measured at Column Line 1	X1	91 ft-0 in	+3 ft -1 ft
Distance from Outside Surface of wall at Column Line 1 to Column Line 7 when Measured at Column Line I	X2	138 ft-0 in	+3 ft -1 ft
Distance from Outside Surface of wall at Column Line 11 to Column Line 7 when Measured at Column Line I	X3	118 ft-0 in	+3 ft -1 ft
Distance between Outside Surface of walls at Column Line I & Q when Measured at Column Line 11	X4	117 ft-6 in	+3 ft -1 ft
Distance from Outside Surface of wall at Column Line Q to Column Line N when Measured at Column Line 11	X5	29 ft-0 in	+3 ft -1 ft
Distance between Outside Surface of shield building wall to shield building centerline when Measured on West Edge of Shield Building	X6	72 ft-6 in	+3 ft -1 ft
Distance between shield building centerline to Reactor Vessel centerline when Measured along Column Line N in North-South Direction	X7	7 ft-6 in	± 3 in
Distance from Bottom of Containment Sump to Top Surface of Embedded Containment Shell	–	2 ft-8 in	± 3 in
Distance from top of Basemat to Design Plant Grade	–	33 ft-6 in	± 1 ft
Distance of Design Plant Grade (Floor elevation 100'-0") relative to Site Grade	–	0 ft	± 3 ft-6 in
Distance from Design Plant Grade to Top Surface of Shield Building Roof	–	234 ft-0 in	± 1 ft

Table 3.3-6 Inspections, Tests, Analyses, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
1. The physical arrangement of the nuclear island structures and the annex building is as described in the Design Description of this Section 3.3 and Figures 3.3-1 through 3.3-14. The physical arrangement of the radwaste building, the turbine building, and the diesel generator building is as described in the Design Description of this Section 3.3.	An inspection of the nuclear island structures, the annex building, the radwaste building, the turbine building, and the diesel generator building will be performed.	The as-built nuclear island structures, the annex building, the radwaste building, the turbine building, and the diesel generator building conform with the physical arrangement as described in the Design Description of this Section 3.3 and Figures 3.3-1 through 3.3-14.
2.a) The nuclear island structures, including the critical sections listed in Table 3.3-7, are seismic Category I and are designed and constructed to withstand design basis loads as specified in the Design Description, without loss of structural integrity and the safety-related functions.	i) An inspection of the nuclear island structures will be performed. Deviations from the design due to as-built conditions will be analyzed for the design basis loads.	i) A report exists which reconciles deviations during construction and concludes that the as-built nuclear island structures, including the critical sections, conform to the approved design and will withstand the design basis loads specified in the Design Description without loss of structural integrity or the safety-related functions.
	ii) An inspection of the as-built concrete thickness will be performed.	ii) A report exists that concludes that the as-built concrete thicknesses conform with the building sections defined on Table 3.3-1.
2.b) Site grade level is located relative to floor elevation 100'-0" per Table 3.3-5.	Inspection of the as-built site grade will be conducted.	Site grade is consistent with design plant grade within the dimension defined on Table 3.3-5.
2.c) The containment and its penetrations are designed and constructed to ASME Code Section III, Class MC.[1]	See Tier 1 Material, Subsection 2.2.1, Containment System.	See Tier 1 Material, Subsection 2.2.1, Containment System.

1. Containment isolation devices are addressed in subsection 2.2.1, Containment System.

Table 3.3-6 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
2.d) The containment and its penetrations retain their pressure boundary integrity associated with the design pressure.	See Tier 1 Material, Subsection 2.2.1, Containment System.	See Tier 1 Material, Subsection 2.2.1, Containment System.
2.e) The containment and its penetrations maintain the containment leakage rate less than the maximum allowable leakage rate associated with the peak containment pressure for the design basis accident.	See Tier 1 Material, Subsection 2.2.1, Containment System.	See Tier 1 Material, Subsection 2.2.1, Containment System.
2.f) The key dimensions of nuclear island structures are defined on Table 3.3-5.	An inspection will be performed of the as-built configuration of the nuclear island structures.	A report exists and concludes that the key dimensions of the as-built nuclear island structures are consistent with the dimensions defined on Table 3.3-5.
2.g) The containment vessel greater than 7 feet above the operating deck provides a heat transfer surface. A free volume exists inside the containment shell above the operating deck.	The maximum containment vessel inside height from the operating deck is measured and the inner radius below the spring line is measured at two orthogonal radial directions at one elevation.	The containment vessel maximum inside height from the operating deck is 146'-7" (with tolerance of +12", -6"), and the inside diameter is 130 feet nominal (with tolerance of +12", -6").
2.h) The free volume in the containment allows for floodup to support long-term core cooling for postulated loss-of-coolant accidents.	An inspection will be performed of the as-built containment structures and equipment. The portions of the containment included in this inspection are the volumes that flood with a loss-of-coolant accident in passive core cooling system valve/equipment room B (11207). The in-containment refueling water storage tank volume is excluded from this inspection.	A report exists and concludes that the floodup volume of this portion of the containment is less than 73,500 ft^3 to an elevation of 108'.
3. Walls and floors of the nuclear island structures as defined on Table 3.3-1 except for designed openings or penetrations provide shielding during normal operations.	Inspection of the as-built nuclear island structures wall and floor thicknesses will be performed.	A report exists and concludes that the shield walls and floors of the nuclear island structures as defined on Table 3.3-1 except for designed openings or penetrations are consistent with the concrete wall thicknesses provided in Table 3.3-1.

Table 3.3-6 (cont.) Inspections, Tests, Analyses, and Acceptance Criteria		
Design Commitment	**Inspections, Tests, Analyses**	**Acceptance Criteria**
4.a) Walls and floors of the annex building as defined on Table 3.3-1 except for designed openings or penetrations provide shielding during normal operations.	Inspection of the as-built annex building wall and floor thicknesses will be performed.	A report exists and concludes that the shield walls and floors of the annex building as defined on Table 3.3-1 except for designed openings or penetrations are consistent with the minimum concrete wall thicknesses provided in Table 3.3-1.
4.b) Walls of the waste accumulation room in the radwaste building except for designed openings or penetrations provide shielding during normal operations.	Inspection of the as-built radwaste building wall thicknesses will be performed.	A report exists and concludes that the shield walls of the waste accumulation room in the radwaste building except for designed openings or penetrations are consistent with the minimum concrete wall thicknesses of 1'-4".
4.c) Walls of the packaged waste storage room in the radwaste building except for designed openings or penetrations provide shielding during normal operations.	Inspection of the as-built radwaste building wall thicknesses will be performed.	A report exists and concludes that the shield walls of the packaged waste storage room in the radwaste building except for the wall shared with the waste accumulation room and designed openings or penetrations are consistent with the minimum concrete wall thicknesses of 2'.
5.a) Exterior walls and the basemat of the nuclear island have a water barrier up to site grade.	An inspection of the as-built exterior walls and the basemat of the nuclear island up to floor elevation 100'-0", for application of water barrier will be performed during construction before the walls are poured.	A report exists that confirms that a water barrier exists on the nuclear island exterior walls up to site grade.
5.b) The boundaries between rooms identified in Table 3.3-2 of the auxiliary building are designed to prevent flooding of rooms that contain safety-related equipment.	An inspection of the auxiliary building rooms will be performed.	A report exists that confirms floors and walls as identified on Table 3.3-2 have provisions to prevent flooding between rooms up to the maximum flood levels for each room defined in Table 3.3-2.

Table 3.3-6 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5.c) The boundaries between the following rooms, which contain safety-related equipment – PXS valve/accumulator room A (11205), PXS valve/accumulator room B (11207), and CVS room (11209) – are designed to prevent flooding between these rooms.	An inspection of the boundaries between the following rooms which contain safety-related equipment – PXS Valve/ Accumulator Room A (11205), PXS Valve/Accumulator Room B (11207), and CVS Room (11209) – will be performed.	A report exists that confirms that flooding of the PXS Valve/ Accumulator Room A (11205), and the PXS/Accumulator Room B (11207) is prevented to a maximum flood level of 110 feet, and of the CVS room (11209) to a maximum flood level of 109'-10".
6.a) The available room volumes of the radiologically controlled area of the auxiliary building between floor elevations 66'-6" and 82'-6" exceed the volume of the liquid radwaste storage tanks (WLS-MT-05A, MT-05B, MT-06A, MT-06B, MT-07A, MT-07B, MT-07C, MT-11).	An inspection will be performed of the as-built radiologically controlled area of the auxiliary building between floor elevations 66'-6" and 82'-6" to define volume.	A report exists and concludes that the as-built available room volumes of the radiologically controlled area of the auxiliary building between floor elevations 66'-6" and 82'-6" exceed the volume of the liquid radwaste storage tanks (WLS-MT-05A, MT-05B, MT-06A, MT-06B, MT-07A, MT-07B, MT-07C, MT-11).
6.b) The radwaste building package waste storage room has a volume greater than or equal to 1293 cubic feet.	An inspection of the radwaste building packaged waste storage room (50352) is performed.	The volume of the radwaste building packaged waste storage room (50352) is greater than or equal to 1293 cubic feet.
7.a) Class 1E electrical cables, communication cables associated with only one division, and raceways are identified according to applicable color-coded Class 1E divisions.	Inspections of the as-built Class 1E cables and raceways will be conducted.	Class 1E electrical cables, communication cables associated with only one division, and raceways are identified by the appropriate color code.
7.b) Class 1E divisional electrical cables and communication cables associated with only one division are routed in their respective divisional raceways.	Inspections of the as-built Class 1E divisional cables and raceways will be conducted.	Class 1E electrical cables and communication cables associated with only one division are routed in raceways assigned to the same division. There are no other safety division electrical cables in a raceway assigned to a different division.

Table 3.3-6 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7.c) Separation is maintained between Class 1E divisions in accordance with the fire areas as identified in Table 3.3-3.	i) Inspections of the as-built Class 1E division electrical cables, communication cables associated with only one division, and raceways located in the fire areas identified in Table 3.3-3 will be conducted. ii) Inspections of the as-built fire barriers between the fire areas identified in Table 3.3-3 will be conducted.	i) Results of the inspection will confirm that the separation between Class 1E divisions is consistent with Table 3.3-3. ii) Results of the inspection will confirm that fire barriers exist between Class 1E divisions consistent with the fire areas identified in Table 3.3-3.
7.d) Physical separation is maintained between Class 1E divisions and between Class 1E divisions and non-Class 1E cables.	Inspections of the as-built Class 1E raceways will be performed to confirm that the separation between Class 1E raceways of different divisions and between Class 1E raceways and non-Class 1E raceways is consistent with the following: – Within the main control room and remote shutdown room, the minimum vertical separation is 3 inches and the minimum horizontal separation is 1 inch.	Results of the inspection will confirm that the separation between Class 1E raceways of different divisions and between Class 1E raceways and non-Class 1E raceways is consistent with the followings: – Within the main control room and remote shutdown room, the vertical separation is 3 inches or more and the horizontal separation is 1 inch or more.

Table 3.3-6 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
	– Within other plant areas (limited hazard areas), the minimum separation is defined by one of the following: 1) The minimum vertical separation is 5 feet and the minimum horizontal separation is 3 feet. 2) The minimum vertical separation is 12 inches and the minimum horizontal separation is 6 inches for raceways containing only instrumentation and control and low-voltage power cables <2/0 AWG. 3) For configurations that involve exclusively limited energy content cables (instrumentation and control), the minimum vertical separation is 3 inches and the minimum horizontal separation is 1 inch. 4) For configurations involving an enclosed raceway and an open raceway, the minimum vertical separation is 1 inch if the enclosed raceway is below the open raceway. 5) For configuration involving enclosed raceways, the minimum separation is 1 inch in both horizontal and vertical directions.	– Within other plant areas (limited hazard areas), the separation meets one of the following: 1) The vertical separation is 5 feet or more and the horizontal separation is 3 feet or more except. 2) The minimum vertical separation is 12 inches and the minimum horizontal separation is 6 inches for raceways containing only instrumentation and control and low-voltage power cables <2/0 AWG. 3) For configurations that involve exclusively limited energy content cables (instrumentation and control), the minimum vertical separation is 3 inches and the minimum horizontal separation is 1 inch. 4) For configurations that involve an enclosed raceway and an open raceway, the minimum vertical separation is 1 inch if the enclosed raceway is below the raceway. 5) For configurations that involve enclosed raceways, the minimum vertical and horizontal separation is 1 inch.

Table 3.3-6 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
	– Where minimum separation distances are not maintained, the circuits are run in enclosed raceways or barriers are provided. – Separation distances less than those specified above and not run in enclosed raceways or provided with barriers are based on analysis – Non-Class 1E wiring that is not separated from Class 1E or associated wiring by the minimum separation distance or by a barrier or analyzed is considered as associated circuits and subject to Class 1E requirements.	– Where minimum separation distances are not met, the circuits are run in enclosed raceways or barriers are provided. – A report exists and concludes that separation distances less than those specified above and not provided with enclosed raceways or barriers have been analyzed. – Non-Class 1E wiring that is not separated from Class 1E or associated wiring by the minimum separation distance or by a barrier or analyzed is treated as Class 1E wiring.
7.e) Class 1E communication cables which interconnect two divisions are routed and separated such that the Protection and Safety Monitoring System voting logic is not defeated by the loss of any single raceway or fire area.	Inspections of the as-built Class 1E communication cables will be conducted.	Class 1E communication cables which interconnect two divisions are routed and separated such that the Protection and Safety Monitoring System voting logic is not defeated by the loss of any single raceway or fire area.
8. Equipment labeled as essential targets in Table 3.3-4 and located in rooms identified in Table 3.3-4 are protected from the dynamic effects of postulated pipe breaks.	An inspection will be performed of the as-built high energy pipe break pipe whip restraints features for systems located in rooms identified in Table 3.3-4.	An as-built Pipe Rupture Hazard Analysis Report exists and concludes that equipment labeled as essential targets in Table 3.3-4 and located in rooms identified in Table 3.3-4 can withstand the effects of postulated pipe rupture without loss of required safety function.
9. The reactor cavity sump has a minimum concrete thickness as shown in Table 3.3-5 between the bottom of the sump and the steel containment.	An inspection of the as-built containment building internal structures will be performed.	A report exists and concludes that the reactor cavity sump has a minimum concrete thickness as shown on Table 3.3-5 between the bottom of the sump and the steel containment.

Table 3.3-6 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
10. The shield building roof and PCS storage tank support and retain the PCS water sources. The PCS storage tank has a stainless steel liner which provides a barrier on the inside surfaces of the tank. Leak chase channels are provided on the tank boundary liner welds.	i) A test will be performed to measure the leakage from the PCS storage tank based on measuring the water flow out of the leak chase collection system. ii) An inspection of the PCS storage tank exterior tank boundary and shield building tension ring will be performed before and after filling of the PCS storage tank to the overflow level. The vertical elevation of the shield building roof will be measured at a location at the outer radius of the roof (tension ring) and at a location on the same azimuth at the outer radius of the PCS water storage tank before and after filling the PCS storage tank.	i) A report exists and concludes that total water flow from the leak chase collection system does not exceed 10 gal/hr. ii) A report exists and concludes that there is no visible water leakage from the PCS storage tank and that inspection and measurement of the structure before and after filling of the tank shows structural behavior under normal loads to be acceptable.
11. Deleted		
12. The extended turbine generator axis intersects the shield building.	An inspection of the as-built turbine generator will be performed.	The extended axis of the turbine generator intersects the shield building.
13. Separation is provided between the structural elements of the turbine, annex and radwaste buildings and the nuclear island structure. This separation permits horizontal motion of the buildings in the safe shutdown earthquake without impact between structural elements of the buildings.	An inspection of the separation of the nuclear island from the annex, radwaste and turbine building structures will be performed. The inspection will verify the specified horizontal clearance between structural elements of the adjacent buildings, consisting of the reinforced concrete walls and slabs, structural steel columns and floor beams.	The minimum horizontal clearance above floor elevation 100′-0″ between the structural elements of the annex and radwaste buildings and the nuclear island is 4 inches. The minimum horizontal clearance above floor elevation 100′-0″ between the structural elements of the turbine building and the nuclear island is 12 inches.
14. The walls, doors, ceiling, and floors in the main control room, central alarm station, and secondary alarm station are bullet-resistant to a level 4 round.	Type test, analysis, or a combination of type test and analysis will be performed for the walls, doors, ceilings, and floors in the main control room, central alarm station, and secondary alarm station.	A report exists and concludes that the walls, doors, ceilings, and floors in the main control room, central alarm station, and secondary alarm station are bullet-resistant to a level 4 round.

Table 3.3-6 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
15. Central alarm station and main control room are vital areas.	An inspection of the as-built central alarm station and main control room will be performed.	Access to the central alarm station and main control room is through an activated intrusion alarm system and at least two security hardened barriers.
16. Security power supply system for alarm annunciator equipment and non-portable communications equipment is located within a vital area.	An inspection of the as-built location of the security power supply for alarm annunciator equipment and non-portable communications equipment will be performed.	Access to the security power supply for alarm annunciator equipment and non-portable communications equipment is through an activated intrusion alarm system and at least two security hardened barriers.
17. Vital areas are locked and alarmed with active intrusion detection systems that annunciate in the central and secondary alarm stations upon intrusion into a vital area.	An inspection of the as-built vital areas, and central and secondary alarm stations are performed.	Vital areas are locked and alarmed with active intrusion detection systems that annunciate in the central and secondary alarm stations upon intrusion into a vital area.
18. The locks used for the protection of the vital areas are manipulative-resistant.	Type test, analysis, or a combination of type test and analysis will be performed for the locks used in the protection of the vital areas.	A report exists and concludes that the locks used for the protection of the vital areas are manipulative-resistant.

Table 3.3-7 Nuclear Island Critical Structural Sections
Containment Internal Structures
South west wall of the refueling cavity
South wall of the west steam generator cavity
North east wall of the in-containment refueling water storage tank
In-containment refueling water storage tank steel wall
Column supporting the operating floor
Auxiliary and Shield Building
South wall of auxiliary building (column line 1), elevation 66'-6" to elevation 180'-0"
Interior wall of auxiliary building (column line 7.3), elevation 66'-6" to elevation 160'-6"
West wall of main control room in auxiliary building (column line L), elevation 117'-6" to elevation 153'-0"
North wall of MSIV east compartment (column line 11 between lines P and Q), elevation 117'-6" to elevation 153'-0"
Shield building cylinder, elevation 160'-6" to elevation 200"-0"
Roof slab at elevation 180'-0" adjacent to shield building cylinder
Floor slab on metal decking at elevation 135'-3"
2'-0" slab in auxiliary building (tagging room ceiling) at elevation 135'-3"
Finned floor in the main control room at elevation 135'-3"
Shield building roof, exterior wall of the PCS water storage tank
Shield building roof, tension ring and columns between air inlets, elevation 265'-0" to elevation 275'-10"
Divider wall between the spent fuel pool and the fuel transfer canal
Nuclear Island Basemat Below Auxiliary Building
Bay between reference column lines 9.1 and 11, and K and L
Bay between reference column lines 1 and 2 and K-2 and N

Withheld under 10 CFR 2.390.

Figure 3.3-1
Nuclear Island Section A-A

Withheld under 10 CFR 2.390.

Figure 3.3-2
Nuclear Island Section B-B

Withheld under 10 CFR 2.390.

Figure 3.3-3
Nuclear Island Plan View at Elevation 66′-6″

Withheld under 10 CFR 2.390.

Figure 3.3-4
Nuclear Island Plan View at Elevation 82′-6″

Withheld under 10 CFR 2.390.

Figure 3.3-5
Nuclear Island Plan View at Elevation 96′-6″

Withheld under 10 CFR 2.390.

Figure 3.3-6
Nuclear Island Plan View at Elevation 100′-0″

Withheld under 10 CFR 2.390.

Figure 3.3-7
Nuclear Island Plan View at Elevation 117′-6″

Withheld under 10 CFR 2.390.

Figure 3.3-8
Nuclear Island Plan View at Elevation 135′-3″

Withheld under 10 CFR 2.390.

Figure 3.3-9
Nuclear Island Plan View at Elevation
153′-3″ and 160′-6″

Withheld under 10 CFR 2.390.

Figure 3.3-10
Nuclear Island Plan View at Shield Building Roof

Withheld under 10 CFR 2.390.

Figure 3.3-11
Annex Building Plan View at Elevation 100′-0″

Withheld under 10 CFR 2.390.

Figure 3.3-12
Annex Building Plan View at Elevation 117′-6″

Withheld under 10 CFR 2.390.

Figure 3.3-13
Annex Building Plan View at Elevation 135′-3″

Withheld under 10 CFR 2.390.

Figure 3.3-14
Nuclear Island Dimensions at
Elevation 66′-6″

3.4 Initial Test Program

Design Description

This section represents a commitment that combined license applicants referencing the AP1000 certified design will implement an initial test program.

An initial test program is performed during the initial startup of each AP1000 plant. The initial test program consists of a series of tests categorized as construction and installation, preoperational (prior to fuel load), and startup (during and after fuel load). All ITAAC will be completed prior to fuel load; therefore, no ITAAC are performed during the startup test phase of the initial test program.

Construction and installation tests are performed to verify the adequacy of construction, installation, and preliminary operation of components and systems. Various electrical and mechanical tests are performed including cleaning and flushing, hydrostatic testing, electrical checks, operability checks, and instrumentation calibration. The completion of the construction and installation test program demonstrates that the system is ready for preoperational testing.

Preoperational tests are performed for each system after construction and installation tests, but prior to initial fuel loading to demonstrate that equipment and systems perform in accordance with design criteria so that initial fuel loading, initial criticality, and subsequent power operation can be safely undertaken. Preoperational tests include, as appropriate, logic and interlock tests, control and instrumentation functional tests, component functional tests, operational and performance tests, and expansion, vibration, and dynamic effects tests.

Startup tests begin with the initial fuel loading and are performed to demonstrate the capability of individual systems, as well as the integrated plant, to meet performance requirements. Startup testing is conducted in four categories: tests related to initial fuel loading, tests performed after initial fuel loading but prior to initial criticality, tests related to initial criticality and those performed at low power (less than 5 percent), and tests performed at power levels greater than 5 percent (ascension to power tests). Startup tests include a controlled fuel load, reactor core and component performance tests, initial criticality, control and protection system operational tests, and plant system performance tests.

Preoperational and startup tests are performed using test specifications and test procedures. The test procedures delineate the test methods to be used in the conduct of the Initial Test Program and the applicable acceptance criteria against which performance is evaluated. Test specifications and procedures are developed and reviewed by qualified personnel. Copies of the test specifications and test procedures for preoperational tests are available to NRC personnel prior to the scheduled performance of these tests. Copies of the test specifications and test procedures for startup tests are provided to NRC inspection personnel prior to the scheduled fuel loading date. Administrative procedures are used to control the conduct of the test program; the review, evaluation and approval of test results; and test record retention.

3.5 Radiation Monitoring

Design Description

Radiation monitoring is provided for those plant areas where there is a significant potential for airborne contamination, for those process and effluent streams where contamination is possible, and in accessible areas to provide indication of unusual radiological events as identified in Tables 3.5-1, 3.5-2, 3.5-3, 3.5-4, and 3.5-5. The radiation monitoring component locations are as shown in Table 3.5-7.

1. The seismic Category I equipment identified in Table 3.5-1 can withstand seismic design basis loads without loss of safety function.

2. The Class 1E equipment identified in Table 3.5-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.

3. Separation is provided between system Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.

4. Safety-related displays identified in Table 3.5-1 can be retrieved in the main control room (MCR).

5. The process radiation monitors listed in Table 3.5-2 are provided.

6. The effluent radiation monitors listed in Table 3.5-3 are provided.

7. The airborne radiation monitors listed in Table 3.5-4 are provided.

8. The area radiation monitors listed in Table 3.5-5 are provided.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 3.5-6 specifies the inspections, tests, analyses, and associated acceptance criteria for radiation monitoring.

Table 3.5-1

Equipment Name	Tag No.	Seismic Cat. I	Class 1E	Qual. for Harsh Envir.	Safety-Related Display
Containment High Range Monitor	PXS-RE160	Yes	Yes	Yes	Yes
Containment High Range Monitor	PXS-RE161	Yes	Yes	Yes	Yes
Containment High Range Monitor	PXS-RE162	Yes	Yes	Yes	Yes
Containment High Range Monitor	PXS-RE163	Yes	Yes	Yes	Yes
MCR Radiation Monitoring Package A(1)	VBS-JS01A	Yes	Yes	No	No
MCR Radiation Monitoring Package B(1)	VBS-JS01B	Yes	Yes	No	No
Containment Atmosphere Monitor (Gaseous)	PSS-RE026	Yes	No	No	No
Containment Atmosphere Monitor (gaseous, for RCS pressure boundary leakage detection)	PSS-RE027	Yes	No	No	No

Notes: (1) Each MCR Radiation Monitoring Package includes particulate, iodine and gaseous radiation monitors.

Table 3.5-2
Process Radiation Monitors

Equipment List	Equipment No.
Steam Generator Blowdown	BDS-RE010
Steam Generator Blowdown	BDS-RE011
Component Cooling Water	CCS-RE001
Main Steam Line	SGS-RE026
Main Steam Line	SGS-RE027
Service Water Blowdown	SWS-RE008
Primary Sampling System Liquid Sample	PSS-RE050
Primary Sampling System Gaseous Sample	PSS-RE052
Containment Air Filtration Exhaust	VFS-RE001
Gaseous Radwaste Discharge	WGS-RE017

Table 3.5-3
Effluent Radiation Monitors

Equipment List	Equipment No.
Plant Vent (Normal Range Particulate)	VFS-RE101
Plant Vent (Normal Range Iodine)	VFS-RE102
Plant Vent (Normal Range Radiogas)	VFS-RE103
Plant Vent (Mid Range Radiogas)	VFS-RE104A
Plant Vent (High Range Radiogas)	VFS-RE104B
Turbine Island Vent	TDS-RE001
Liquid Radwaste Discharge	WLS-RE229
Wastewater Discharge	WWS-RE021

Table 3.5-4
Airborne Radiation Monitors

Equipment List	Equipment No.
Fuel Handling Area Exhaust Radiation Monitor	VAS-RE-001
Auxiliary Building Exhaust Radiation Monitor	VAS-RE-002
Annex Building Exhaust Radiation Monitor	VAS-RE003
Health Physics and Hot Machine Shop Exhaust Radiation Monitor	VHS-RE001
Radwaste Building Exhaust Radiation Monitor	VRS-RE023

Table 3.5-5
Area Radiation Monitors

Primary Sampling Room Area Monitor	RMS-RE008
Technical Support Center Area Monitor	RMS-RE016
Main Control Room Area Monitor	RMS-RE010

Table 3.5-6
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The seismic Category I equipment identified in Table 3.5-1 can withstand seismic design basis loads without loss of safety function.	i) Inspection will be performed to verify that the seismic Category I equipment identified in Table 3.5-1 is located on the Nuclear Island.	i) The seismic Category I equipment identified in Table 3.5-1 is located on the Nuclear Island.
	ii) Type tests, analyses, or a combination of type tests and analyses of seismic Category I equipment will be performed.	ii) A report exists and concludes that the seismic Category I equipment can withstand seismic design basis loads without loss of safety function.
	iii) Inspection will be performed for the existence of a report verifying that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.	iii) A report exists and concludes that the as-installed equipment including anchorage is seismically bounded by the tested or analyzed conditions.
2. The Class 1E equipment identified in Table 3.5-1 as being qualified for a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.	i) Type tests, analyses, or a combination of type tests and analyses will be performed on Class 1E equipment located in a harsh environment.	i) A report exists and concludes that Class 1E equipment identified in Table 3.5-1 as being located in a harsh environment can withstand the environmental conditions that would exist before, during, and following a design basis accident without loss of safety function for the time required to perform the safety function.
	ii) Inspection will be performed of the as-installed Class 1E equipment and the associated wiring, cables, and terminations located in a harsh environment.	ii) A report exists and concludes that the as-installed Class 1E equipment and the associated wiring, cables, and terminations identified in Table 3.5-1 as being qualified for a harsh environment are bounded by type tests, analyses, or a combination of type tests and analyses.
3. Separation is provided between system Class 1E divisions, and between Class 1E divisions and non-Class 1E cable.	See Tier 1 Material, Table 3.3-6, item 7.d).	See Tier 1 Material, Table 3.3-6, item 7.d).

Table 3.5-6 (cont.)
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4. Safety-related displays identified in Table 3.5-1 can be retrieved in the MCR.	Inspection will be performed for retrievability of the displays in the MCR.	Safety-related displays identified in Table 3.5-1 can be retrieved in the MCR.
5. The process radiation monitors listed in Table 3.5-2 are provided.	Inspection for the existence of the monitors will be performed.	Each of the monitors listed in Table 3.5-2 exists.
6. The effluent radiation monitors listed in Table 3.5-3 are provided.	Inspection for the existence of the monitors will be performed.	Each of the monitors listed in Table 3.5-3 exists.
7. The airborne radiation monitors listed in Table 3.5-4 are provided.	Inspection for the existence of the monitors will be performed.	Each of the monitors listed in Table 3.5-4 exists.
8. The area radiation monitors listed in Table 3.5-5 are provided.	Inspection for the existence of the monitors will be performed.	Each of the monitors listed in Table 3.5-5 exists.

Table 3.5-7		
Component Name	**Tag No.**	**Component Location**
Containment High Range Radiation Monitor	PXS-RE160	Containment
Containment High Range Radiation Monitor	PXS-RE161	Containment
Containment High Range Radiation Monitor	PXS-RE162	Containment
Containment High Range Radiation Monitor	PXS-RE163	Containment
MCR Radiation Monitoring Package A	VBS-RE01A	Auxiliary Building
MCR Radiation Monitoring Package B	VBS-RE01B	Auxiliary Building
Containment Atmosphere Radiation Monitor (Gaseous)	PSS-RE026	Auxiliary Building
Containment Atmosphere Radiation Monitor (gaseous, for RCS pressure boundary leakage detection)	PSS-RE027	Auxiliary Building
Steam Generator Blowdown Radiation Monitor	BDS-RE010	Turbine Building
Steam Generator Blowdown Radiation Monitor	BDS-RE011	Turbine Building
Component Cooling Water Radiation Monitor	CCS-RE001	Turbine Building
Main Steam Line Radiation Monitor	SGS-RE026	Auxiliary Building
Main Steam Line Radiation Monitor	SGS-RE027	Auxiliary Building
Service Water Blowdown Radiation Monitor	SWS-RE008	Turbine Building
Primary Sampling System Liquid Sample Radiation Monitor	PSS-RE050	Auxiliary Building
Primary Sampling System Gaseous Sample Radiation Monitor	PSS-RE052	Auxiliary Building
Containment Air Filtration Exhaust Radiation Monitor	VFS-RE001	Annex Building
Gaseous Radwaste Discharge Radiation Monitor	WGS-RE017	Auxiliary Building
Plant Vent (Normal Range Particulate) Radiation Monitor	VFS-RE101	Auxiliary Building
Plant Vent (Normal Range Iodine) Radiation Monitor	VFS-RE102	Auxiliary Building
Plant Vent (Normal Range Radiogas) Radiation Monitor	VFS-RE103	Auxiliary Building
Plant Vent (Mid Range Radiogas) Radiation Monitor	VFS-RE104A	Auxiliary Building
Plant Vent (High Range Radiogas) Radiation Monitor	VFS-RE104B	Auxiliary Building
Turbine Island Vent Radiation Monitor	TDS-RE001	Turbine Building
Liquid Radwaste Discharge Monitor	WLS-RE229	Auxiliary Building

Table 3.5-7 (cont.)		
Component Name	**Tag No.**	**Component Location**
Wastewater Discharge Radiation Monitor	WWS-RE021	Yard/Turbine Building
Fuel Handling Area Exhaust Radiation Monitor	VAS-RE-001	Auxiliary Building
Auxiliary Building Exhaust Radiation Monitor	VAS-RE-002	Auxiliary Building
Annex Building Exhaust Radiation Monitor	VAS-RE003	Auxiliary Building
Health Physics and Hot Machine Shop Exhaust Radiation Monitor	VHS-RE001	Annex Building
Radwaste Building Exhaust Radiation Monitor	VRS-RE023	Radwaste Building
Primary Sampling Room Area Radiation Monitor	RMS-RE008	Auxiliary Building
Technical Support Center Area Radiation Monitor	RMS-RE016	Annex Building
Main Control Room Area Radiation Monitor	RMS-RE010	Auxiliary Building

3.6 Reactor Coolant Pressure Boundary Leak Detection

Design Description

The reactor coolant pressure boundary leakage detection monitoring provides a means of detecting and quantifying the reactor coolant leakage. To detect unidentified leakage inside containment, the following diverse methods are provided to quantify and assist in locating the leakage:

- Containment Sump Level
- Reactor Coolant System Inventory Balance
- Containment Atmosphere Radiation

Leakage detection monitoring is accomplished using instrumentation and other components of several systems.

1. The diverse leak detection methods provide the nonsafety-related function of detecting small leaks when RCS leakage indicates possible reactor coolant pressure boundary degradation.

Inspection, Tests, Analyses, and Acceptance Criteria

Table 3.6-1 specifies the inspections, tests, analyses, and associated acceptance criteria for the leak detection equipment.

Table 3.6-1
Inspections, Tests, Analyses, and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The diverse leak detection methods provide the nonsafety-related function of detecting small leaks when RCS leakage indicates possible reactor coolant pressure boundary degradation.	See Tier 1 Material sections: i) Subsection 2.3.10 for the containment sump level measuring instruments WLS-034 and WLS-035 ii) Section 3.5 for the containment atmosphere radioactivity monitor PSS-RE027 iii) Subsection 2.1.2 for the pressurizer level measuring instruments RCS-195A, RCS-195B, RCS-195C, and RCS-195D iv) Subsection 2.1.2 for the RCS hot and cold leg temperature instruments RCS-121A, RCS-121B, RCS-121C, RCS-121D, RCS-122A, RCS-122B, RCS-122C, RCS-122D, RCS-131A, RCS-131B, RCS-131C, RCS-131D, RCS-132A, RCS-132B, RCS-132C, RCS-132D v) Subsection 2.1.2 for the RCS pressure instruments RCS-140A, RCS-140B, RCS-140C, RCS-140D vi) Subsection 2.3.2 for the letdown and makeup flow instruments CVS-001 and CVS-025 vii) Subsection 2.3.10 for the reactor coolant drain tank level instrument WLS-002	See Tier 1 Material sections: i) Subsection 2.3.10 for the containment sump level measuring instruments WLS-034 and WLS-035 ii) Section 3.5 for the containment atmosphere radioactivity monitor PSS-RE027 iii) Subsection 2.1.2 for the pressurizer level measuring instruments RCS-195A, RCS-195B, RCS-195C, and RCS-195D iv) Subsection 2.1.2 for the RCS hot and cold leg temperature instruments RCS-121A, RCS-121B, RCS-121C, RCS-121D, RCS-122A, RCS-122B, RCS-122C, RCS-122D, RCS-131A, RCS-131B, RCS-131C, RCS-131D, RCS-132A, RCS-132B, RCS-132C, RCS-132D v) Subsection 2.1.2 for the RCS pressure instruments RCS-140A, RCS-140B, RCS-140C, RCS-140D vi) Subsection 2.3.2 for the letdown and makeup flow instruments CVS-001 and CVS-025 vii) Subsection 2.3.10 for the reactor coolant drain tank level instrument WLS-002

3.7 Design Reliability Assurance Program

The Design Reliability Assurance Program (D-RAP) is a program that will be performed during the detailed design and equipment specification phase prior to initial fuel load. The D-RAP evaluates and sets priorities for the structures, systems, and components (SSCs) in the design, based on their degree of risk significance. The risk-significant components are listed in Table 3.7-1.

The objective of the D-RAP program is to provide reasonable assurance that risk-significant SSCs (Table 3.7-1) are designed such that: (1) assumptions from the risk analysis are utilized, (2) SSCs (Table 3.7-1) when challenged, function in accordance with the assumed reliability, (3) SSCs (Table 3.7-1) whose failure results in a reactor trip, function in accordance with the assumed reliability, and (4) maintenance actions to achieve the assumed reliability are identified.

1. The D-RAP provides reasonable assurance that the design of risk-significant SSCs is consistent with their risk analysis assumptions.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 3.7-3 specifies the inspections, tests, analyses, and associated acceptance criteria for the D-RAP.

Table 3.7-1
Risk-Significant Components

Equipment Name	Tag No.
Component Cooling Water System (CCS)	
Component Cooling Water Pumps	CCS-MP-01A/B
Containment System (CNS)	
Containment Vessel	CNS-MV-01
Hydrogen Igniters	VLS-EH-1 through -64
Chemical and Volume Control System (CVS)	
Makeup Pumps	CVS-MP-01A/B
Makeup Pump Suction and Discharge Check Valves	CVS-PL-V113 CVS-PL-V160A/B
Diverse Actuation System (DAS)	
DAS Processor Cabinets and Control Panel (used to provide automatic and manual actuation)	DAS-JD-001 DAS-JD-002 OCS-JC-020
Annex Building UPS Distribution Panels (provide power to DAS)	EDS1-EA-1, EDS1-EA-14, EDS2-EA-1, EDS2-EA-14

Table 3.7-1 (cont.)
Risk-Significant Components

Equipment Name	Tag No.
Rod Drive MG Sets (Field Breakers)	PLS-MG-01A/B
Containment Isolation Valves Controlled by DAS	Refer to Table 2.2.1-1
Main ac Power System (ECS)	
Reactor Coolant Pump Switchgear	ECS-ES-31, -32, -41, -42, -51, -52, -61, -62
Ancillary Diesel Generators	ECS-MS-01, -02
Main and Startup Feedwater System (FWS)	
Startup Feedwater Pumps	FWS-MP-03A/B
General I&C	
IRWST Level Sensors	PXS-045, -046, -047, -048
RCS Hot Leg Level Sensors	RCS-160A/B
Pressurizer Pressure Sensors	RCS-191A/B/C/D
Pressurizer Level Sensors	RCS-195A/B/C/D
Steam Generator Narrow-Range Level Sensors	SGS-001, -002, -003, -004, -005, -006, -007, -008
Steam Generator Wide-Range Level Sensors	SGS-011, -012, -013, -014, -015, -016, -017, -018
Main Steam Line Pressure Sensors	SGS-030, -031, -032, -033, -034, -035, -036, -037
Main Feedwater Wide-Range Flow Sensors	SGS-050A/C/E, -051A/C/E
Startup Feedwater Flow Sensors	SGS-055A/B, -056A/B
CMT Level Sensors	PXS-011A/B/C/D, -012A/B/C/D, -013A/B/C/D, -014A/B/C/D
Class 1E dc Power and Uninterruptible Power System (IDS)	
125 Vdc 24-Hour Batteries	IDSA-DB-1A/B, IDSB-DB-1A/B, IDSC-DB-1A/B, IDSD-DB-1A/B
125 Vdc 24-Hour Battery Chargers	IDSA-DC-1, IDSB-DC-1, IDSC-DC-1, IDSD-DC-1

Table 3.7-1 (cont.) Risk-Significant Components	
Equipment Name	**Tag No.**
125 Vdc and 120 Vac Distribution Panels	IDSA-DD-1, IDSA-EA-1/-2, IDSB-DD-1, IDSB-EA-1/-2/-3, IDSC-DD-1, IDSC-EA-1/-2/-3, IDSD-DD-1, IDSD-EA-1/-2
Fused Transfer Switch Boxes	IDSA-DF-1, IDSB-DF-1/-2, IDSC-DF-1/-2, IDSD-DF-1
125 Vdc Motor Control Centers	IDSA-DK-1, IDSB-DK-1, IDSC-DK-1, IDSD-DK-1
125 Vdc 24-Hour Inverters	IDSA-DU-1, IDSB-DU-1, IDSC-DU-1, IDSD-DU-1
Passive Containment Cooling System (PCS)	
Recirculation Pumps	PCS-MP-01A/B
PCCWST Drain Isolation Valves	PCS-PL-V001A/B/C
Plant Control System (PLS)	
PLS Actuation Software and Hardware (used to provide control functions)	Refer to Table 3.7-2
Protection and Monitoring System (PMS)	
PMS Actuation Software (used to provide automatic control functions)	Refer to Tables 2.5.2-2 and 2.5.2-3
PMS Actuation Hardware (used to provide automatic control functions)	Refer to Tables 2.5.2-2 and 2.5.2-3
MCR 1E Displays and System Level Controls	OCS-JC-010, -011
Reactor Trip Switchgear	PMS-JD-RTS A01/02, B01/02, C01/02, D01/02
Passive Core Cooling System (PXS)	
IRWST Vents	PXS-MT-03
IRWST Screens	PXS-MY-Y01A/B
Containment Recirculation Screens	PXS-MY-Y02A/B
CMT Discharge Isolation Valves	PXS-PL-V014A/B, -V015A/B
CMT Discharge Check Valves	PXS-PL-V016A/B, -V017A/B
Accumulator Discharge Check Valves	PXS-PL-V028A/B, -V029A/B
PRHR HX Control Valves	PXS-PL-V108A/B

Table 3.7-1 (cont.) Risk-Significant Components	
Equipment Name	**Tag No.**
Containment Recirculation Squib Valves	PXS-PL-V118A/B, -V120A/B
IRWST Injection Check Valves	PXS-PL-V122A/B, -V124A/B
IRWST Injection Squib Valves	PXS-PL-V123A/B, -V125A/B
IRWST Gutter Bypass Isolation Valves	PXS-PL-V130A/B
Reactor Coolant System (RCS)	
ADS Stage 1/2/3 Valves (MOVs)	RCS-PL-V001A/B, -V011A/B RCS-PL-V002A/B, -V012A/B RCS-PL-V003A/B, -V013A/B
ADS Stage 4 Valves (Squibs)	RCS-PL-V004A/B/C/D
Pressurizer Safety Valves	RCS-PL-V005A/B
Reactor Vessel Insulation Water Inlet and Steam Vent Devices	RCS-MN-01
Reactor Cavity Doorway Damper	–
Fuel Assemblies	157 assemblies with tag numbers beginning with RXS-FA
Normal Residual Heat Removal System (RNS)	
Residual Heat Removal Pumps	RNS-MP-01A/B
RNS Motor-Operated Valves	RNS-PL-V011, -V022, -V055, -V062
Spent Fuel Cooling System (SFS)	
Spent Fuel Cooling Pumps	SFS-MP-01A/B
Steam Generator System (SGS)	
Main Steam Safety Valves	SGS-PL-V030A/B, -V031A/B, -V032A/B, -V033A/B, -V034A/B, -V035A/B
Main Steam Line Isolation Valves	SGS-PL-V040A/B
Main Feedwater Isolation Valves	SGS-PL-V057A/B
Service Water System (SWS)	
Service Water Cooling Tower Fans	MA-01A/B
Service Water Pumps	SWS-MP-01A/B

Table 3.7-1 (cont.) Risk-Significant Components	
Equipment Name	**Tag No.**
Nuclear Island Nonradioactive Ventilation System (VBS)	
MCR Ancillary Fans	VBS-MA-10A/B
I&C Room B/C Ancillary Fans	VBS-MA-11, -12
Chilled Water System (VWS)	
Air Cooled Chiller Pumps	VWS-MP-02, -03
Air Cooled Chillers	VWS-MS-02, -03
Onsite Standby Power System (ZOS)	
Engine Room Exhaust Fans	VZS-MY-V01A/B, -V02A/B
Onsite Diesel Generators	ZOS-MS-05A/B

Note: Dash (-) indicates not applicable.

Table 3.7-2
PLS D-RAP Control Functions

CVS Reactor Makeup
RNS Reactor Injection from cask loading pit
Startup Feedwater from CST
Spent Fuel Cooling
Component Cooling of RNS and SFS Heat Exchangers
Service Water Cooling of CCS Heat Exchangers
Onsite Diesel Generators
Hydrogen Ignitors

Table 3.7-3
Inspections, Tests, Analyses and Acceptance Criteria

Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The D-RAP provides reasonable assurance that the design of risk-significant SSCs is consistent with their risk analysis assumptions.	Inspection will be performed for the existence of a report which establishes the estimated reliability of as-built risk-significant SSCs.	A report exists and concludes that the estimated reliability of each as-built component identified in Table 3.7-1 is at least equal to the assumed reliability and that industry experience including operations, maintenance, and monitoring activities were assessed in estimating the reliability of these SSCs.

4.0 Interface Requirements

The 10 CFR 52.47 (a)(1)(vii) requires identification of the interface requirements to be met by those portions of the plant for which the application does not seek certification. The 10 CFR 52.47 (a)(1)(viii) requires justification that these interfaces be verifiable through inspection, testing (either in the plant or elsewhere), or analysis. An applicant for a combined license (COL) that references the Certified Design must provide design features or characteristics that comply with the interface requirements for the plant design and inspections, tests, analyses, and acceptance criteria (ITAAC) for the site-specific portion of the facility design, in accordance with 10 CFR 52.79 (c).

No Tier 1 interfaces were identified for the AP1000 standard plant design.

5.0 Site Parameters

Table 5.0-1 identifies the key site parameters that are specified for the design of safety-related aspects of structures, systems, and components for the AP1000. An actual site is acceptable if its site characteristics fall within the AP1000 plant site design parameters in Table 5.0-1.

Table 5.0-1
Site Parameters

Maximum Ground Water Level	Plant elevation 98 ft
Maximum Flood Level	Plant elevation 100 ft (design grade elevation)
Precipitation	
Rain	19.4 in./hr (6.3 in./5 min)
Snow/Ice	Ground snow load of 75 lb/ft^2 with exposure factor of 1.0 and importance factor of 1.2
Air Temperature	Limits based on historical data excluding peaks of less than 2 hours duration Maximum temperature of 115° dry bulb/80°F coincident wet bulb Maximum wet bulb 81°F (noncoincident) Minimum temperature of -40°F
Tornado	
Wind Speed	Maximum wind speed of 300 mph
Maximum Pressure Differential	Maximum pressure differential of 2.0 lb/in^2
Tornado Missile Spectra	4000-lb automobile at 105 mph horizontal, 74 mph vertical 275-lb, 8-in. shell at 105 mph horizontal, 74 mph vertical 1-in.-diameter steel ball at 105 mph in the most damaging direction

Table 5.0-1 (cont.)
Site Parameters

Soil	
Average Allowable Static Soil Bearing Capacity	Greater than or equal to 8,600 lb/ft^2 over the footprint of the nuclear island at its excavation depth
Maximum Allowable Dynamic Bearing Capacity for Normal Plus Safe Shutdown Earthquake (SSE)	Greater than or equal to 120,000 lb/ft^2 at the edge of the nuclear island at its excavation depth
Shear Wave Velocity	Greater than or equal to 8000 ft/sec based on low-strain, best-estimate soil properties over the footprint of the nuclear island at its excavation depth
Liquefaction Potential	None
Seismic	
SSE	SSE free field peak ground acceleration of 0.30 g at foundation level of nuclear island with modified Regulatory Guide 1.60 response spectra (See Figures 5.0-1 and 5.0-2.)
Fault Displacement Potential	None
Atmospheric Dispersion Factors (X/Q)	
Site Boundary (0-2 hr)	$\leq 5.1 \times 10^{-4}$ sec/m^3
Site Boundary (annual average)	$\leq 2.0 \times 10^{-5}$ sec/m^3
Low Population Zone Boundary	
0 - 8 hr	$\leq 2.2 \times 10^{-4}$ sec/m^3
8 - 24 hr	$\leq 1.6 \times 10^{-4}$ sec/m^3
24 - 96 hr	$\leq 1.0 \times 10^{-4}$ sec/m^3
96 - 720 hr	$\leq 8.0 \times 10^{-5}$ sec/m^3

Table 5.0-1 (cont.)
Site Parameters

Control Room Atmospheric Dispersion Factors (χ/Q) for Accident Dose Analysis					
χ/Q (s/m^3) at HVAC Intake for the Identified Release Points(1)					
	Plant Vent or PCS Air Diffuser(3)	**Ground Level Containment Release Points(4)**	**PORV and Safety Valve Releases(5)**	**Steam Line Break Releases**	**Fuel Handling Area(6)**
0 - 2 hours	2.2E-3	2.2E-3	2.0E-2	2.4E-2	6.0E-3
2 - 8 hours	1.4E-3	1.4E-3	1.8E-2	2.0E-2	4.0E-3
8 - 24 hours	6.0E-4	6.0E-4	7.0E-3	7.5E-3	2.0E-3
1 - 4 days	4.5E-4	4.5E-4	5.0E-3	5.5E-3	1.5E-3
4 - 30 days	3.6E-4	3.6E-4	4.5E-3	5.0E-3	1.0E-3
χ/Q (s/m^3) at Control Room Door for the Identified Release Points(2)					
0 - 2 hours	6.6E-4	6.6E-4	4.0E-3	4.0E-3	6.0E-3
2 - 8 hours	4.8E-4	4.8E-4	3.2E-3	3.2E-3	4.0E-3
8 - 24 hours	2.1E-4	2.1E-4	1.2E-3	1.2E-3	2.0E-3
1 - 4 days	1.5E-4	1.5E-4	1.0E-3	1.0E-3	1.5E-3
4 - 30 days	1.3E-4	1.3E-4	8.0E-4	8.0E-4	1.0E-3

Notes:

1. These dispersion factors are to be used 1) for the time period preceding the isolation of the main control room and actuation of the emergency habitability system, 2) for the time after 72 hours when the compressed air supply in the emergency habitability system would be exhausted and outside air would be drawn into the main control room, and 3) for the determination of control room doses when the nonsafety ventilation system is assumed to remain operable such that the emergency habitability system is not actuated.
2. These dispersion factors are to be used when the emergency habitability system is in operation and the only path for outside air to enter the main control room is that due to ingress/egress.
3. These dispersion factors are used for analysis of the doses due to a postulated small line break outside of containment. The plant vent and PCS air diffuser are potential release paths for other postulated events (loss-of-coolant accident, rod ejection accident, and fuel handling accident inside the containment); however, the values are bounded by the dispersion factors for ground level releases.
4. The listed values represent modeling the containment shell as a diffuse area source, and are used for evaluating the doses in the main control room for a loss-of-coolant accident, for the containment leakage of activity following a rod ejection accident, and for a fuel handling accident occurring inside the containment.
5. The listed values bound the dispersion factors for releases from the steam line safety and power-operated relief valves, and the condenser air removal stack. These dispersion factors would be used for evaluating the doses in the main control room for a steam generator tube rupture, a main steam line break, a locked reactor coolant pump rotor, and the secondary side release from a rod ejection accident. Additionally, these dispersion coefficients are conservative for the small line break outside containment.
6. The listed values bound the dispersion factors for releases from the fuel storage and handling area. The listed values also bound the dispersion factors for releases from the fuel storage area in the event that spent fuel boiling occurs and the fuel building relief panel opens on high temperature. These dispersion factors are used for the fuel handling accident occurring outside containment and for evaluating the impact of releases associated with spent fuel pool boiling.

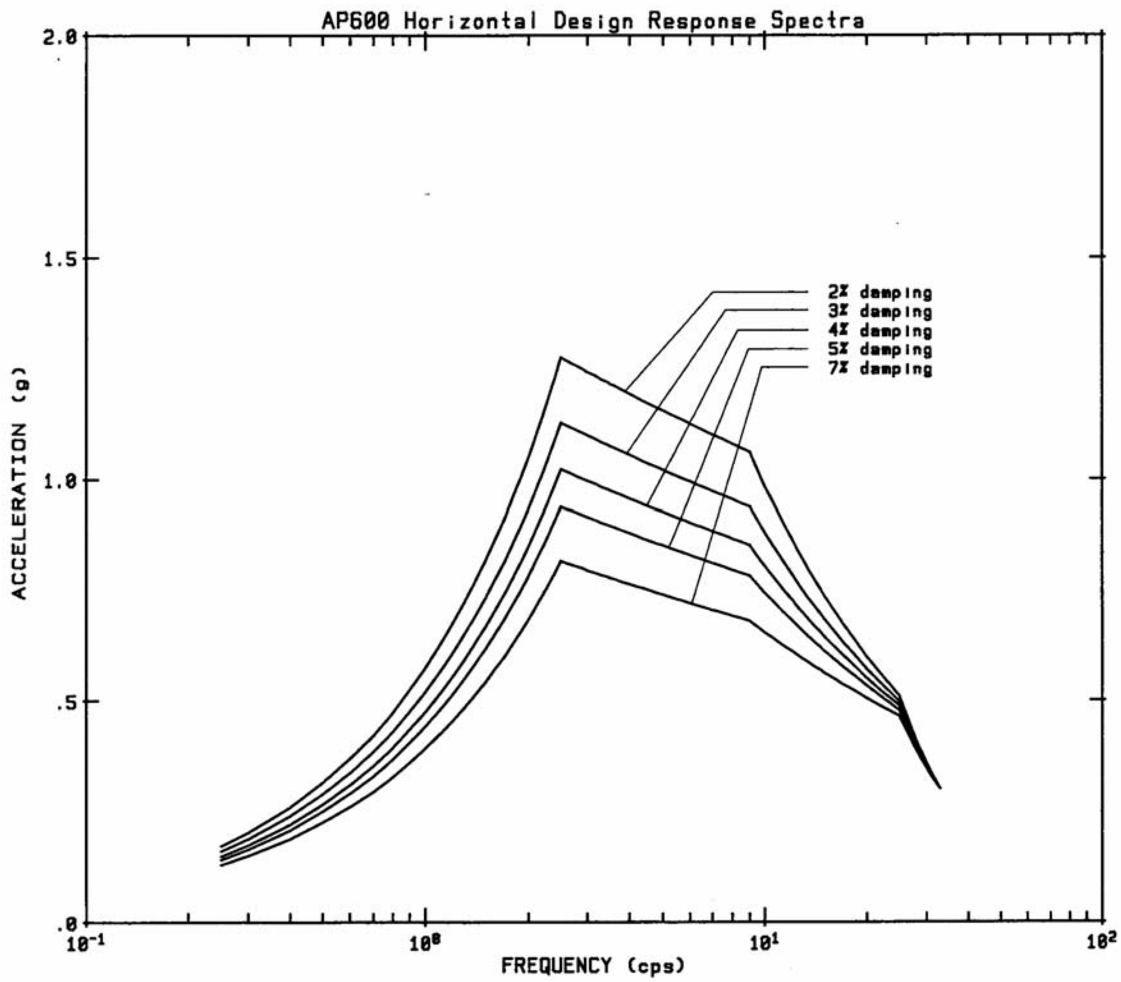


Figure 5.0-1
Horizontal Design Response Spectra
Safe Shutdown Earthquake

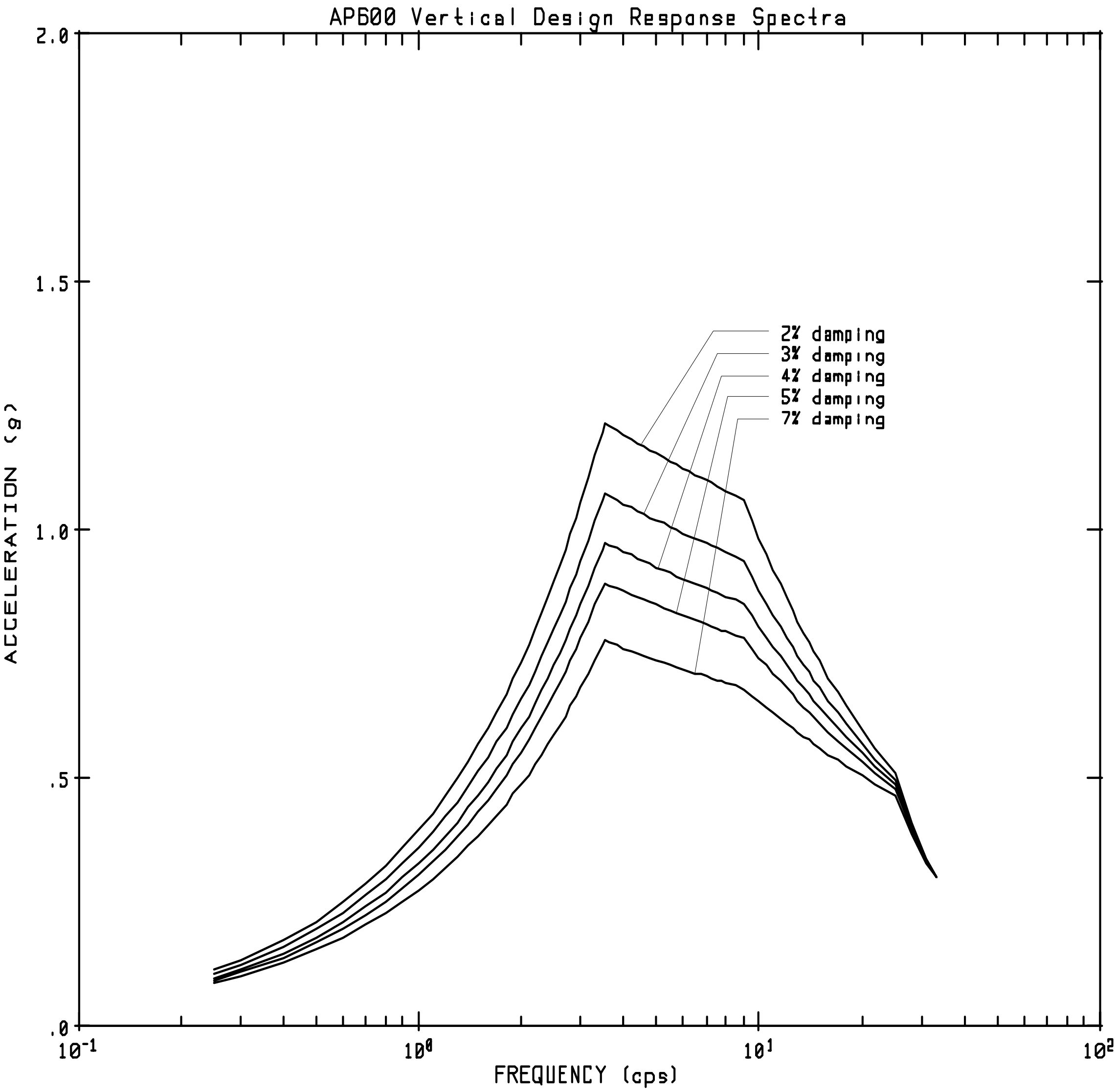


Figure 5.0-2
Vertical Design Response Spectra
Safe Shutdown Earthquake

TIER 2 MASTER TABLE OF CONTENTS

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

Section **Title** **Page**

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

TIER 2 MASTER TABLE OF CONTENTS (Cont.)

[This page intentionally blank]

AP1000
TIER 2 LIST OF EFFECTIVE PAGES

Page	Revision	Page	Revision	Page	Revision	Page	Revision
i	15	xliv	15	lxxxvii	15	1.1-1	3
ii	15	xlv	15	lxxxviii	15	1.1-2	0
iii	15	xlvi	15	lxxxix	15	1.1-3	0
iv	15	xlvii	15	xc	15	1.1-4	3
v	15	xlviii	15	xci	15	1.1-5	0
vi	15	xlix	15	xcii	15	1.1-6	0
vii	15	l	15	xciii	15		
viii	15	li	15	xciv	15	1.2-1	10
ix	15	lii	15	xcv	15	1.2-2	10
x	15	liii	15	xcvi	15	1.2-3	10
xi	15	liv	15	xcvii	15	1.2-4	10
xii	15	lv	15	xcviii	15	1.2-5	10
xiii	15	lvi	15	xcix	15	1.2-6	10
xiv	15	lvii	15	c	15	1.2-7	10
xv	15	lviii	15	ci	15	1.2-8	10
xvi	15	lix	15	cii	15	1.2-9	10
xvii	15	lx	15	ciii	15	1.2-10	10
xviii	15	lxi	15	civ	15	1.2-11	10
xix	15	lxii	15	cv	15	1.2-12	10
xx	15	lxiii	15	cvi	15	1.2-13	10
xxi	15	lxiv	15	cvii	15	1.2-14	10
xxii	15	lxv	15	cviii	15	1.2-15	10
xxiii	15	lxvi	15	cix	15	1.2-16	10
xxiv	15	lxvii	15	cx	15	1.2-17	10
xxv	15	lxviii	15	cxi	15	1.2-18	10
xxvi	15	lxix	15	cxii	15	1.2-19	10
xxvii	15	lxx	15	cxiii	15	1.2-20	10
xxviii	15	lxxi	15	cxiv	15	1.2-21	10
xxix	15	lxxii	15	cxv	15	1.2-22	10
xxx	15	lxxiii	15	cxvi	15	1.2-23	10
xxxi	15	lxxiv	15	cxvii	15	1.2-24	10
xxxii	15	lxxv	15	cxviii	15	1.2-25	10
xxxiii	15	lxxvi	15	cxix	15	1.2-26	10
xxxiv	15	lxxvii	15	cxx	15	1.2-27	10
xxxv	15	lxxviii	15			1.2-29	10
xxxvi	15	lxxix	15			1.2-31	10
xxxvii	15	lxxx	15			1.2-33	10
xxxviii	15	lxxxi	15	i	9	1.2-35	10
xxxix	15	lxxxii	15	ii	9	1.2-37	10
xl	15	lxxxiii	15	iii	9	1.2-39	10
xli	15	lxxxiv	15	iv	9	1.2-41	10
xlii	15	lxxxv	15	v	9	1.2-43	10
xliii	15	lxxxvi	15			1.2-45	10

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
1.2-47	10	1.6-1	14	1.8-9	13	1.9-34	14
1.2-49	10	1.6-2	14	1.8-10	13	1.9-35	14
1.2-51	10	1.6-3	14	1.8-11	13	1.9-36	14
1.2-53	10	1.6-4	14	1.8-12	13	1.9-37	14
1.2-55	10	1.6-5	14	1.8-13	13	1.9-38	14
1.2-57	10	1.6-6	14	1.8-14	13	1.9-39	14
1.2-59	10	1.6-7	14	1.8-15	13	1.9-40	14
1.2-61	10	1.6-8	14	1.8-16	13	1.9-41	14
1.2-63	10	1.6-9	14	1.8-17	13	1.9-42	14
1.2-65	10	1.6-10	14			1.9-43	14
1.2-67	10	1.6-11	14	1.9-1	14	1.9-44	14
1.2-69	10	1.6-12	14	1.9-2	14	1.9-45	14
1.2-71	10	1.6-13	14	1.9-3	14	1.9-46	14
1.2-73	10	1.6-14	14	1.9-4	14	1.9-47	14
1.2-75	10	1.6-15	14	1.9-5	14	1.9-48	14
1.2-77	10	1.6-16	14	1.9-6	14	1.9-49	14
1.2-79	10	1.6-17	14	1.9-7	14	1.9-50	14
1.2-81	10	1.6-18	14	1.9-8	14	1.9-51	14
1.2-83	10	1.6-19	14	1.9-9	14	1.9-52	14
1.2-85	10	1.6-20	14	1.9-10	14	1.9-53	14
		1.6-21	14	1.9-11	14	1.9-54	14
1.3-1	15			1.9-12	14	1.9-55	14
1.3-2	15	1.7-1	11	1.9-13	14	1.9-56	14
1.3-3	15	1.7-2	11	1.9-14	14	1.9-57	14
1.3-4	15	1.7-3	11	1.9-15	14	1.9-58	14
1.3-5	15	1.7-4	11	1.9-16	14	1.9-59	14
1.3-6	15	1.7-5	11	1.9-17	14	1.9-60	14
1.3-7	15	1.7-6	11	1.9-18	14	1.9-61	14
		1.7-7	11	1.9-19	14	1.9-62	14
1.4-1	0	1.7-9	11	1.9-20	14	1.9-63	14
1.4-2	0	1.7-11	11	1.9-21	14	1.9-64	14
1.4-3	0	1.7-13	11	1.9-22	14	1.9-65	14
		1.7-15	11	1.9-23	14	1.9-66	14
1.5-1	14	1.7-17	11	1.9-24	14	1.9-67	14
1.5-2	14			1.9-25	14	1.9-68	14
1.5-3	14	1.8-1	13	1.9-26	14	1.9-69	14
1.5-4	14	1.8-2	13	1.9-27	14	1.9-70	14
1.5-5	14	1.8-3	13	1.9-28	14	1.9-71	14
1.5-6	14	1.8-4	13	1.9-29	14	1.9-72	14
1.5-7	14	1.8-5	13	1.9-30	14	1.9-73	14
1.5-8	14	1.8-6	13	1.9-31	14	1.9-74	14
1.5-9	14	1.8-7	13	1.9-32	14	1.9-75	14
1.5-10	14	1.8-8	13	1.9-33	14	1.9-76	14

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
1B-20	9	xiv	12	3.1-32	7	3.2-39	15
1B-21	9	xv	12	3.1-33	7	3.2-40	15
1B-22	9	xvi	12	3.1-34	7	3.2-41	15
1B-23	9	xvii	12	3.1-35	7	3.2-42	15
		xviii	12			3.2-43	15
		xix	12	3.2-1	15	3.2-44	15
		xx	12	3.2-2	15	3.2-45	15
i	9	xxi	12	3.2-3	15	3.2-46	15
ii	9	xxii	12	3.2-4	15	3.2-47	15
		xxiii	12	3.2-5	15	3.2-48	15
2-1	12	xxiv	12	3.2-6	15	3.2-49	15
2-2	12			3.2-7	15	3.2-50	15
2-3	12	3.1-1	7	3.2-8	15	3.2-51	15
2-4	12	3.1-2	7	3.2-9	15	3.2-52	15
2-5	12	3.1-3	7	3.2-10	15	3.2-53	15
2-6	12	3.1-4	7	3.2-11	15	3.2-54	15
2-7	12	3.1-5	7	3.2-12	15	3.2-55	15
2-8	12	3.1-6	7	3.2-13	15	3.2-56	15
2-9	12	3.1-7	7	3.2-14	15	3.2-57	15
2-10	12	3.1-8	7	3.2-15	15	3.2-58	15
2-11	12	3.1-9	7	3.2-16	15	3.2-59	15
2-12	12	3.1-10	7	3.2-17	15	3.2-60	15
2-13	12	3.1-11	7	3.2-18	15	3.2-61	15
2-14	12	3.1-12	7	3.2-19	15	3.2-62	15
2-15	12	3.1-13	7	3.2-20	15	3.2-63	15
2-16	12	3.1-14	7	3.2-21	15	3.2-64	15
2-17	12	3.1-15	7	3.2-22	15	3.2-65	15
		3.1-16	7	3.2-23	15	3.2-66	15
		3.1-17	7	3.2-24	15	3.2-67	15
		3.1-18	7	3.2-25	15	3.2-68	15
i	12	3.1-19	7	3.2-26	15	3.2-69	15
ii	12	3.1-20	7	3.2-27	15	3.2-70	15
iii	12	3.1-21	7	3.2-28	15	3.2-71	15
iv	12	3.1-22	7	3.2-29	15	3.2-72	15
v	12	3.1-23	7	3.2-30	15	3.2-73	15
vi	12	3.1-24	7	3.2-31	15	3.2-74	15
vii	12	3.1-25	7	3.2-32	15	3.2-75	15
viii	12	3.1-26	7	3.2-33	15	3.2-76	15
ix	12	3.1-27	7	3.2-34	15	3.2-77	15
x	12	3.1-28	7	3.2-35	15	3.2-78	15
xi	12	3.1-29	7	3.2-36	15	3.2-79	15
xii	12	3.1-30	7	3.2-37	15	3.2-80	15
xiii	12	3.1-31	7	3.2-38	15	3.2-81	15

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
3.2-82	15	3.5-8	0	3.6-35	14	3.7-28	11
3.2-83	15	3.5-9	0	3.6-36	14	3.7-29	11
3.2-84	15	3.5-10	0	3.6-37	14	3.7-30	11
		3.5-11	0	3.6-38	14	3.7-31	11
3.3-1	8	3.5-12	0	3.6-39	14	3.7-32	11
3.3-2	8	3.5-13	0	3.6-40	14	3.7-33	11
3.3-3	8	3.5-14	0	3.6-41	14	3.7-34	11
3.3-4	8	3.5-15	0	3.6-42	14	3.7-35	11
3.3-5	8			3.6-43	14	3.7-36	11
3.3-6	8	3.6-1	14	3.6-44	14	3.7-37	11
		3.6-2	14	3.6-45	14	3.7-38	11
3.4-1	8	3.6-3	14	3.6-46	14	3.7-39	11
3.4-2	8	3.6-4	14	3.6-47	14	3.7-40	11
3.4-3	8	3.6-5	14	3.6-48	14	3.7-41	11
3.4-4	8	3.6-6	14	3.6-49	14	3.7-42	11
3.4-5	8	3.6-7	14			3.7-43	11
3.4-6	8	3.6-8	14	3.7-1	11	3.7-44	11
3.4-7	8	3.6-9	14	3.7-2	11	3.7-45	11
3.4-8	8	3.6-10	14	3.7-3	11	3.7-46	11
3.4-9	8	3.6-11	14	3.7-4	11	3.7-47	11
3.4-10	8	3.6-12	14	3.7-5	11	3.7-48	11
3.4-11	8	3.6-13	14	3.7-6	11	3.7-49	11
3.4-12	8	3.6-14	14	3.7-7	11	3.7-50	11
3.4-13	8	3.6-15	14	3.7-8	11	3.7-51	11
3.4-14	8	3.6-16	14	3.7-9	11	3.7-52	11
3.4-15	8	3.6-17	14	3.7-10	11	3.7-53	11
3.4-16	8	3.6-18	14	3.7-11	11	3.7-54	11
3.4-17	8	3.6-19	14	3.7-12	11	3.7-55	11
3.4-18	8	3.6-20	14	3.7-13	11	3.7-56	11
3.4-19	8	3.6-21	14	3.7-14	11	3.7-57	11
3.4-20	8	3.6-22	14	3.7-15	11	3.7-58	11
3.4-21	8	3.6-23	14	3.7-16	11	3.7-59	11
3.4-22	8	3.6-24	14	3.7-17	11	3.7-60	11
3.4-23	8	3.6-25	14	3.7-18	11	3.7-61	11
3.4-24	8	3.6-26	14	3.7-19	11	3.7-62	11
		3.6-27	14	3.7-20	11	3.7-63	11
3.5-1	0	3.6-28	14	3.7-21	11	3.7-64	11
3.5-2	0	3.6-29	14	3.7-22	11	3.7-65	11
3.5-3	0	3.6-30	14	3.7-23	11	3.7-66	11
3.5-4	0	3.6-31	14	3.7-24	11	3.7-67	11
3.5-5	0	3.6-32	14	3.7-25	11	3.7-68	11
3.5-6	0	3.6-33	14	3.7-26	11	3.7-69	11
3.5-7	4	3.6-34	14	3.7-27	11	3.7-70	11

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
3.7-71	11	3.7-114	11	3.7-169	11	3.8-11	14
3.7-72	11	3.7-115	11	3.7-170	11	3.8-12	14
3.7-73	11	3.7-116	11	3.7-171	11	3.8-13	14
3.7-74	11	3.7-117	11	3.7-172	11	3.8-14	14
3.7-75	11	3.7-118	11	3.7-173	11	3.8-15	14
3.7-76	11	3.7-119	11	3.7-174	11	3.8-16	14
3.7-77	11	3.7-120	11	3.7-175	11	3.8-17	14
3.7-78	11	3.7-121	11	3.7-176	11	3.8-18	14
3.7-79	11	3.7-122	11	3.7-177	11	3.8-19	14
3.7-80	11	3.7-123	11	3.7-178	11	3.8-20	14
3.7-81	11	3.7-124	11	3.7-179	11	3.8-21	14
3.7-82	11	3.7-125	11	3.7-180	11	3.8-22	14
3.7-83	11	3.7-126	11	3.7-181	11	3.8-23	14
3.7-84	11	3.7-127	11	3.7-182	11	3.8-24	14
3.7-85	11	3.7-128	11	3.7-183	11	3.8-25	14
3.7-86	11	3.7-129	11	3.7-184	11	3.8-26	14
3.7-87	11	3.7-130	11	3.7-185	11	3.8-27	14
3.7-88	11	3.7-131	11	3.7-186	11	3.8-28	14
3.7-89	11	3.7-133	11	3.7-187	11	3.8-29	14
3.7-90	11	3.7-135	11	3.7-188	11	3.8-30	14
3.7-91	11	3.7-137	11	3.7-189	11	3.8-31	14
3.7-92	11	3.7-139	11	3.7-191	11	3.8-32	14
3.7-93	11	3.7-141	11	3.7-193	11	3.8-33	14
3.7-94	11	3.7-143	11	3.7-195	11	3.8-34	14
3.7-95	11	3.7-145	11	3.7-197	11	3.8-35	14
3.7-96	11	3.7-147	11	3.7-199	11	3.8-36	14
3.7-97	11	3.7-149	11	3.7-201	11	3.8-37	14
3.7-98	11	3.7-151	11	3.7-203	11	3.8-38	14
3.7-99	11	3.7-153	11	3.7-205	11	3.8-39	14
3.7-100	11	3.7-155	11	3.7-207	11	3.8-40	14
3.7-101	11	3.7-156	11	3.7-209	11	3.8-41	14
3.7-102	11	3.7-157	11	3.7-210	11	3.8-42	14
3.7-103	11	3.7-158	11			3.8-43	14
3.7-104	11	3.7-159	11	3.8-1	14	3.8-44	14
3.7-105	11	3.7-160	11	3.8-2	14	3.8-45	14
3.7-106	11	3.7-161	11	3.8-3	14	3.8-46	14
3.7-107	11	3.7-162	11	3.8-4	14	3.8-47	14
3.7-108	11	3.7-163	11	3.8-5	14	3.8-48	14
3.7-109	11	3.7-164	11	3.8-6	14	3.8-49	14
3.7-110	11	3.7-165	11	3.8-7	14	3.8-50	14
3.7-111	11	3.7-166	11	3.8-8	14	3.8-51	14
3.7-112	11	3.7-167	11	3.8-9	14	3.8-52	14
3.7-113	11	3.7-168	11	3.8-10	14	3.8-53	14

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
3.8-54	14	3.8-99	14	3.8-151	14	3.9-9	14
3.8-55	14	3.8-101	14	3.8-152	14	3.9-10	14
3.8-56	14	3.8-102	14	3.8-153	14	3.9-11	14
3.8-57	14	3.8-103	14	3.8-154	14	3.9-12	14
3.8-58	14	3.8-104	14	3.8-155	14	3.9-13	14
3.8-59	14	3.8-105	14	3.8-156	14	3.9-14	14
3.8-60	14	3.8-107	14	3.8-157	14	3.9-15	14
3.8-61	14	3.8-109	14	3.8-158	14	3.9-16	14
3.8-62	14	3.8-110	14	3.8-159	14	3.9-17	14
3.8-63	14	3.8-111	14	3.8-160	14	3.9-18	14
3.8-64	14	3.8-112	14	3.8-161	14	3.9-19	14
3.8-65	14	3.8-113	14	3.8-163	14	3.9-20	14
3.8-66	14	3.8-114	14	3.8-165	14	3.9-21	14
3.8-67	14	3.8-115	14	3.8-167	14	3.9-22	14
3.8-68	14	3.8-116	14	3.8-169	14	3.9-23	14
3.8-69	14	3.8-117	14	3.8-170	14	3.9-24	14
3.8-70	14	3.8-118	14	3.8-171	14	3.9-25	14
3.8-71	14	3.8-119	14	3.8-172	14	3.9-26	14
3.8-72	14	3.8-120	14	3.8-173	14	3.9-27	14
3.8-73	14	3.8-121	14	3.8-174	14	3.9-28	14
3.8-74	14	3.8-122	14	3.8-175	14	3.9-29	14
3.8-75	14	3.8-123	14	3.8-176	14	3.9-30	14
3.8-76	14	3.8-124	14	3.8-177	14	3.9-31	14
3.8-77	14	3.8-125	14	3.8-178	14	3.9-32	14
3.8-78	14	3.8-126	14	3.8-179	14	3.9-33	14
3.8-79	14	3.8-127	14	3.8-180	14	3.9-34	14
3.8-80	14	3.8-128	14	3.8-181	14	3.9-35	14
3.8-81	14	3.8-129	14	3.8-183	14	3.9-36	14
3.8-82	14	3.8-131	14	3.8-184	14	3.9-37	14
3.8-83	14	3.8-133	14	3.8-185	14	3.9-38	14
3.8-84	14	3.8-135	14	3.8-186	14	3.9-39	14
3.8-85	14	3.8-136	14	3.8-187	14	3.9-40	14
3.8-86	14	3.8-137	14	3.8-188	14	3.9-41	14
3.8-87	14	3.8-138	14	3.8-189	14	3.9-42	14
3.8-88	14	3.8-139	14			3.9-43	14
3.8-89	14	3.8-140	14	3.9-1	14	3.9-44	14
3.8-90	14	3.8-141	14	3.9-2	14	3.9-45	14
3.8-91	14	3.8-142	14	3.9-3	14	3.9-46	14
3.8-92	14	3.8-143	14	3.9-4	14	3.9-47	14
3.8-93	14	3.8-145	14	3.9-5	14	3.9-48	14
3.8-94	14	3.8-147	14	3.9-6	14	3.9-49	14
3.8-95	14	3.8-149	14	3.9-7	14	3.9-50	14
3.8-97	14	3.8-150	14	3.9-8	14	3.9-51	14

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
3.9-52	14	3.9-95	14	3.9-155	14	3.11-18	15
3.9-53	14	3.9-96	14	3.9-157	14	3.11-19	15
3.9-54	14	3.9-97	14	3.9-159	14	3.11-20	15
3.9-55	14	3.9-98	14	3.9-161	14	3.11-21	15
3.9-56	14	3.9-99	14	3.9-163	14	3.11-22	15
3.9-57	14	3.9-100	14	3.9-165	14	3.11-23	15
3.9-58	14	3.9-101	14	3.9-167	14	3.11-24	15
3.9-59	14	3.9-102	14	3.9-168	14	3.11-25	15
3.9-60	14	3.9-103	14	3.9-169	14	3.11-26	15
3.9-61	14	3.9-104	14	3.9-170	14	3.11-27	15
3.9-62	14	3.9-105	14	3.9-171	14	3.11-28	15
3.9-63	14	3.9-106	14	3.9-172	14	3.11-29	15
3.9-64	14	3.9-107	14	3.9-173	14	3.11-30	15
3.9-65	14	3.9-108	14	3.9-174	14	3.11-31	15
3.9-66	14	3.9-109	14	3.9-175	14	3.11-32	15
3.9-67	14	3.9-110	14	3.9-176	14	3.11-33	15
3.9-68	14	3.9-111	14	3.9-177	14	3.11-34	15
3.9-69	14	3.9-112	14			3.11-35	15
3.9-70	14	3.9-113	14	3.10-1	0	3.11-36	15
3.9-71	14	3.9-114	14	3.10-2	0	3.11-37	15
3.9-72	14	3.9-115	14	3.10-3	0	3.11-38	15
3.9-73	14	3.9-116	14	3.10-4	0	3.11-39	15
3.9-74	14	3.9-117	14	3.10-5	3	3.11-40	15
3.9-75	14	3.9-118	14	3.10-6	3	3.11-41	15
3.9-76	14	3.9-119	14	3.10-7	0	3.11-42	15
3.9-77	14	3.9-120	14			3.11-43	15
3.9-78	14	3.9-121	14	3.11-1	15	3.11-44	15
3.9-79	14	3.9-123	14	3.11-2	15	3.11-45	15
3.9-80	14	3.9-125	14	3.11-3	15	3.11-46	15
3.9-81	14	3.9-127	14	3.11-4	15	3.11-47	15
3.9-82	14	3.9-129	14	3.11-5	15	3.11-48	15
3.9-83	14	3.9-131	14	3.11-6	15	3.11-49	15
3.9-84	14	3.9-133	14	3.11-7	15	3.11-50	15
3.9-85	14	3.9-135	14	3.11-8	15		
3.9-86	14	3.9-137	14	3.11-9	15	3A-1	0
3.9-87	14	3.9-139	14	3.11-10	15	3A-2	0
3.9-88	14	3.9-141	14	3.11-11	15	3A-3	0
3.9-89	14	3.9-143	14	3.11-12	15	3A-4	0
3.9-90	14	3.9-145	14	3.11-13	15		
3.9-91	14	3.9-147	14	3.11-14	15	3B-1	0
3.9-92	14	3.9-149	14	3.11-15	15	3B-2	0
3.9-93	14	3.9-151	14	3.11-16	15	3B-3	0
3.9-94	14	3.9-153	14	3.11-17	15	3B-4	3

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
3B-5	0	3C-4	0	3D-41	12	3D-84	12
3B-6	0	3C-5	0	3D-42	12	3D-85	12
3B-7	0			3D-43	12	3D-86	12
3B-8	0	3D-1	12	3D-44	12	3D-87	12
3B-9	0	3D-2	12	3D-45	12	3D-88	12
3B-10	0	3D-3	12	3D-46	12	3D-89	12
3B-11	0	3D-4	12	3D-47	12	3D-90	12
3B-12	0	3D-5	12	3D-48	12	3D-91	12
3B-13	0	3D-6	12	3D-49	12	3D-92	12
3B-14	0	3D-7	12	3D-50	12	3D-93	12
3B-15	0	3D-8	12	3D-51	12	3D-94	12
3B-16	3	3D-9	12	3D-52	12	3D-95	12
3B-17	0	3D-10	12	3D-53	12	3D-96	12
3B-18	0	3D-11	12	3D-54	12	3D-97	12
3B-19	2	3D-12	12	3D-55	12	3D-98	12
3B-20	2	3D-13	12	3D-56	12	3D-99	12
3B-21	1	3D-14	12	3D-57	12	3D-100	12
3B-22	0	3D-15	12	3D-58	12	3D-101	12
3B-23	2	3D-16	12	3D-59	12	3D-102	12
3B-24	0	3D-17	12	3D-60	12	3D-103	12
3B-25	0	3D-18	12	3D-61	12	3D-104	12
3B-26	0	3D-19	12	3D-62	12	3D-105	12
3B-27	0	3D-20	12	3D-63	12	3D-106	12
3B-28	1	3D-21	12	3D-64	12	3D-107	12
3B-29	1	3D-22	12	3D-65	12	3D-108	12
3B-30	1	3D-23	12	3D-66	12	3D-109	12
3B-31	1	3D-24	12	3D-67	12	3D-110	12
3B-32	1	3D-25	12	3D-68	12	3D-111	12
3B-33	0	3D-26	12	3D-69	12	3D-112	12
3B-34	0	3D-27	12	3D-70	12	3D-113	12
3B-35	2	3D-28	12	3D-71	12	3D-114	12
3B-36	2	3D-29	12	3D-72	12	3D-115	12
3B-37	0	3D-30	12	3D-73	12	3D-116	12
3B-38	3	3D-31	12	3D-74	12		
3B-39	2	3D-32	12	3D-75	12	3E-1	3
3B-40	0	3D-33	12	3D-76	12	3E-2	0
3B-41	2	3D-34	12	3D-77	12	3E-3	0
3B-42	2	3D-35	12	3D-78	12	3E-5	0
		3D-36	12	3D-79	12	3E-7	0
3C-1	0	3D-37	12	3D-80	12	3E-9	0
3C-2	0	3D-38	12	3D-81	12	3E-11	0
3C-3	0	3D-39	12	3D-82	12	3E-13	1
		3D-40	12	3D-83	12	3E-15	0

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
3E-17	0	3H-35	12	4.1-1	14	4.2-31	14
3E-19	0	3H-36	12	4.1-2	14	4.2-32	14
		3H-37	12	4.1-3	14	4.2-33	14
3F-1	0	3H-38	12	4.1-4	14	4.2-34	14
3F-2	0	3H-39	12	4.1-5	14	4.2-35	14
3F-3	0	3H-40	12	4.1-6	14	4.2-36	14
		3H-41	12	4.1-7	14	4.2-37	14
3G-1	0	3H-42	12	4.1-8	14	4.2-38	14
		3H-43	12	4.1-9	14	4.2-39	14
3H-1	12	3H-44	12	4.1-10	14	4.2-41	14
3H-2	12	3H-45	12	4.1-11	14	4.2-42	14
3H-3	12	3H-46	12	4.1-12	14	4.2-43	14
3H-4	12	3H-47	12			4.2-44	14
3H-5	12	3H-48	12	4.2-1	14	4.2-45	14
3H-6	12	3H-49	12	4.2-2	14	4.2-46	14
3H-7	12	3H-50	12	4.2-3	14	4.2-47	14
3H-8	12	3H-51	12	4.2-4	14	4.2-48	14
3H-9	12	3H-52	12	4.2-5	14	4.2-49	14
3H-10	12	3H-53	12	4.2-6	14	4.2-50	14
3H-11	12	3H-55	12	4.2-7	14	4.2-51	14
3H-12	12	3H-57	12	4.2-8	14	4.2-52	14
3H-13	12	3H-58	12	4.2-9	14	4.2-53	14
3H-14	12	3H-59	12	4.2-10	14		
3H-15	12	3H-60	12	4.2-11	14	4.3-1	14
3H-16	12	3H-61	12	4.2-12	14	4.3-2	14
3H-17	12	3H-62	12	4.2-13	14	4.3-3	14
3H-18	12	3H-63	12	4.2-14	14	4.3-4	14
3H-19	12	3H-64	12	4.2-15	14	4.3-5	14
3H-20	12	3H-65	12	4.2-16	14	4.3-6	14
3H-21	12	3H-66	12	4.2-17	14	4.3-7	14
3H-22	12	3H-67	12	4.2-18	14	4.3-8	14
3H-23	12	3H-68	12	4.2-19	14	4.3-9	14
3H-24	12	3H-69	12	4.2-20	14	4.3-10	14
3H-25	12			4.2-21	14	4.3-11	14
3H-26	12			4.2-22	14	4.3-12	14
3H-27	12			4.2-23	14	4.3-13	14
3H-28	12	i	11	4.2-24	14	4.3-14	14
3H-29	12	ii	11	4.2-25	14	4.3-15	14
3H-30	12	iii	11	4.2-26	14	4.3-16	14
3H-31	12	iv	11	4.2-27	14	4.3-17	14
3H-32	12	v	11	4.2-28	14	4.3-18	14
3H-33	12	vi	11	4.2-29	14	4.3-19	14
3H-34	12	vii	11	4.2-30	14	4.3-20	14

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
4.3-21	14	4.3-64	14	4.4-17	14	v	15
4.3-22	14	4.3-65	14	4.4-18	14	vi	15
4.3-23	14	4.3-66	14	4.4-19	14	vii	15
4.3-24	14	4.3-67	14	4.4-20	14		
4.3-25	14	4.3-68	14	4.4-21	14	5.1-1	15
4.3-26	14	4.3-69	14	4.4-22	14	5.1-2	15
4.3-27	14	4.3-70	14	4.4-23	14	5.1-3	15
4.3-28	14	4.3-71	14	4.4-24	14	5.1-4	15
4.3-29	14	4.3-72	14	4.4-25	14	5.1-5	15
4.3-30	14	4.3-73	14	4.4-26	14	5.1-6	15
4.3-31	14	4.3-74	14	4.4-27	14	5.1-7	15
4.3-32	14	4.3-75	14	4.4-28	14	5.1-8	15
4.3-33	14	4.3-76	14	4.4-29	14	5.1-9	15
4.3-34	14	4.3-77	14	4.4-30	14	5.1-10	15
4.3-35	14	4.3-78	14	4.4-31	14	5.1-11	15
4.3-36	14	4.3-79	14	4.4-32	14	5.1-12	15
4.3-37	14	4.3-80	14	4.4-33	14	5.1-13	15
4.3-38	14	4.3-81	14	4.4-34	14	5.1-14	15
4.3-39	14	4.3-82	14	4.4-35	14	5.1-15	15
4.3-40	14	4.3-83	14	4.4-36	14	5.1-17	15
4.3-41	14	4.3-84	14	4.4-37	14	5.1-18	15
4.3-42	14	4.3-85	14	4.4-38	14	5.1-19	15
4.3-43	14	4.3-86	14	4.4-39	14	5.1-21	15
4.3-44	14	4.3-87	14	4.4-40	14	5.1-23	15
4.3-45	14	4.3-88	14	4.4-41	14		
4.3-46	14	4.3-89	14	4.4-42	14	5.2-1	11
4.3-47	14					5.2-2	11
4.3-48	14	4.4-1	14	4.5-1	11	5.2-3	11
4.3-49	14	4.4-2	14	4.5-2	11	5.2-4	11
4.3-50	14	4.4-3	14	4.5-3	11	5.2-5	11
4.3-51	14	4.4-4	14	4.5-4	11	5.2-6	11
4.3-52	14	4.4-5	14			5.2-7	11
4.3-53	14	4.4-6	14	4.6-1	0	5.2-8	11
4.3-54	14	4.4-7	14	4.6-2	0	5.2-9	11
4.3-55	14	4.4-8	14	4.6-3	0	5.2-10	11
4.3-56	14	4.4-9	14	4.6-4	0	5.2-11	11
4.3-57	14	4.4-10	14			5.2-12	11
4.3-58	14	4.4-11	14			5.2-13	11
4.3-59	14	4.4-12	14			5.2-14	11
4.3-60	14	4.4-13	14	i	15	5.2-15	11
4.3-61	14	4.4-14	14	ii	15	5.2-16	11
4.3-62	14	4.4-15	14	iii	15	5.2-17	11
4.3-63	14	4.4-16	14	iv	15	5.2-18	11

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
5.2-19	11	5.3-24	15	5.4-28	15	5.4-71	15
5.2-20	11	5.3-25	15	5.4-29	15	5.4-72	15
5.2-21	11	5.3-26	15	5.4-30	15	5.4-73	15
5.2-22	11	5.3-27	15	5.4-31	15	5.4-74	15
5.2-23	11	5.3-28	15	5.4-32	15	5.4-75	15
5.2-24	11	5.3-29	15	5.4-33	15	5.4-76	15
5.2-25	11	5.3-30	15	5.4-34	15	5.4-77	15
5.2-26	11	5.3-31	15	5.4-35	15	5.4-78	15
5.2-27	11	5.3-32	15	5.4-36	15	5.4-79	15
5.2-28	11	5.3-33	15	5.4-37	15	5.4-80	15
5.2-29	11	5.3-34	15	5.4-38	15	5.4-81	15
5.2-30	11	5.3-35	15	5.4-39	15	5.4-82	15
5.2-31	11	5.3-36	15	5.4-40	15	5.4-83	15
5.2-32	11	5.3-37	15	5.4-41	15	5.4-84	15
5.2-33	11	5.3-38	15	5.4-42	15	5.4-85	15
5.2-34	11			5.4-43	15	5.4-86	15
5.2-35	11	5.4-1	15	5.4-44	15	5.4-87	15
5.2-36	11	5.4-2	15	5.4-45	15	5.4-88	15
5.2-37	11	5.4-3	15	5.4-46	15	5.4-89	15
		5.4-4	15	5.4-47	15	5.4-90	15
5.3-1	15	5.4-5	15	5.4-48	15	5.4-91	15
5.3-2	15	5.4-6	15	5.4-49	15	5.4-92	15
5.3-3	15	5.4-7	15	5.4-50	15	5.4-93	15
5.3-4	15	5.4-8	15	5.4-51	15	5.4-94	15
5.3-5	15	5.4-9	15	5.4-52	15	5.4-95	15
5.3-6	15	5.4-10	15	5.4-53	15	5.4-96	15
5.3-7	15	5.4-11	15	5.4-54	15	5.4-97	15
5.3-8	15	5.4-12	15	5.4-55	15	5.4-98	15
5.3-9	15	5.4-13	15	5.4-56	15	5.4-99	15
5.3-10	15	5.4-14	15	5.4-57	15	5.4-100	15
5.3-11	15	5.4-15	15	5.4-58	15	5.4-101	15
5.3-12	15	5.4-16	15	5.4-59	15	5.4-102	15
5.3-13	15	5.4-17	15	5.4-60	15	5.4-103	15
5.3-14	15	5.4-18	15	5.4-61	15	5.4-105	15
5.3-15	15	5.4-19	15	5.4-62	15		
5.3-16	15	5.4-20	15	5.4-63	15		
5.3-17	15	5.4-21	15	5.4-64	15		
5.3-18	15	5.4-22	15	5.4-65	15	i	9
5.3-19	15	5.4-23	15	5.4-66	15	ii	9
5.3-20	15	5.4-24	15	5.4-67	15	iii	9
5.3-21	15	5.4-25	15	5.4-68	15	iv	9
5.3-22	15	5.4-26	15	5.4-69	15	v	9
5.3-23	15	5.4-27	15	5.4-70	15	vi	9

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
vii	9	6.2-23	14	6.2-66	14	6.2-113	14
viii	9	6.2-24	14	6.2-67	14	6.2-114	14
		6.2-25	14	6.2-68	14	6.2-115	14
6.0-1	0	6.2-26	14	6.2-69	14	6.2-116	14
6.0-2	0	6.2-27	14	6.2-70	14	6.2-117	14
		6.2-28	14	6.2-71	14	6.2-118	14
6.1-1	14	6.2-29	14	6.2-72	14	6.2-119	14
6.1-2	14	6.2-30	14	6.2-73	14	6.2-120	14
6.1-3	14	6.2-31	14	6.2-74	14	6.2-121	14
6.1-4	14	6.2-32	14	6.2-75	14	6.2-122	14
6.1-5	14	6.2-33	14	6.2-76	14	6.2-123	14
6.1-6	14	6.2-34	14	6.2-77	14	6.2-124	14
6.1-7	14	6.2-35	14	6.2-78	14	6.2-125	14
6.1-8	14	6.2-36	14	6.2-79	14	6.2-126	14
6.1-9	14	6.2-37	14	6.2-80	14	6.2-127	14
6.1-10	14	6.2-38	14	6.2-81	14	6.2-129	14
6.1-11	14	6.2-39	14	6.2-82	14	6.2-131	14
6.1-12	14	6.2-40	14	6.2-83	14	6.2-132	14
6.1-13	14	6.2-41	14	6.2-84	14	6.2-133	14
6.1-14	14	6.2-42	14	6.2-85	14	6.2-134	14
		6.2-43	14	6.2-86	14	6.2-135	14
6.2-1	14	6.2-44	14	6.2-87	14	6.2-136	14
6.2-2	14	6.2-45	14	6.2-88	14	6.2-137	14
6.2-3	14	6.2-46	14	6.2-89	14	6.2-138	14
6.2-4	14	6.2-47	14	6.2-90	14	6.2-139	14
6.2-5	14	6.2-48	14	6.2-91	14	6.2-140	14
6.2-6	14	6.2-49	14	6.2-92	14	6.2-141	14
6.2-7	14	6.2-50	14	6.2-93	14	6.2-142	14
6.2-8	14	6.2-51	14	6.2-94	14	6.2-143	14
6.2-9	14	6.2-52	14	6.2-95	14		
6.2-10	14	6.2-53	14	6.2-97	14	6.3-1	13
6.2-11	14	6.2-54	14	6.2-99	14	6.3-2	13
6.2-12	14	6.2-55	14	6.2-101	14	6.3-3	13
6.2-13	14	6.2-56	14	6.2-103	14	6.3-4	13
6.2-14	14	6.2-57	14	6.2-104	14	6.3-5	13
6.2-15	14	6.2-58	14	6.2-105	14	6.3-6	13
6.2-16	14	6.2-59	14	6.2-106	14	6.3-7	13
6.2-17	14	6.2-60	14	6.2-107	14	6.3-8	13
6.2-18	14	6.2-61	14	6.2-108	14	6.3-9	13
6.2-19	14	6.2-62	14	6.2-109	14	6.3-10	13
6.2-20	14	6.2-63	14	6.2-110	14	6.3-11	13
6.2-21	14	6.2-64	14	6.2-111	14	6.3-12	13
6.2-22	14	6.2-65	14	6.2-112	14	6.3-13	13

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision
6.3-14	13
6.3-15	13
6.3-16	13
6.3-17	13
6.3-18	13
6.3-19	13
6.3-20	13
6.3-21	13
6.3-22	13
6.3-23	13
6.3-24	13
6.3-25	13
6.3-26	13
6.3-27	13
6.3-28	13
6.3-29	13
6.3-30	13
6.3-31	13
6.3-32	13
6.3-33	13
6.3-34	13
6.3-35	13
6.3-36	13
6.3-37	13
6.3-38	13
6.3-39	13
6.3-40	13
6.3-41	13
6.3-42	13
6.3-43	13
6.3-44	13
6.3-45	13
6.3-46	13
6.3-47	13
6.3-48	13
6.3-49	13
6.3-50	13
6.3-51	13
6.3-52	13
6.3-53	13
6.3-54	13
6.3-55	13
6.3-56	13
6.3-57	13
6.3-58	13
6.3-59	13
6.3-61	13
6.3-63	13
6.3-64	13
6.3-65	13
6.3-66	13
6.3-67	13
6.3-68	13
6.3-69	13
6.4-1	12
6.4-2	12
6.4-3	12
6.4-4	12
6.4-5	12
6.4-6	12
6.4-7	12
6.4-8	12
6.4-9	12
6.4-10	12
6.4-11	12
6.4-12	12
6.4-13	12
6.4-14	12
6.4-15	12
6.4-16	12
6.4-17	12
6.4-19	12
6.5-1	0
6.5-2	0
6.5-3	0
6.5-4	0
6.5-5	0
6.5-6	0
6.5-7	0
6.5-8	0
6.6-1	0
6.6-2	0
6.6-3	0
6.6-4	0
6A-1	14
6A-2	14
6A-3	14
6A-4	14
6A-5	14
6A-6	14
6A-7	14
6A-8	14
6A-9	14
6A-10	14
6A-11	14
i	12
ii	12
iii	12
iv	12
v	12
vi	12
7.1-1	14
7.1-2	14
7.1-3	14
7.1-4	14
7.1-5	14
7.1-6	14
7.1-7	14
7.1-8	14
7.1-9	14
7.1-10	14
7.1-11	14
7.1-12	14
7.1-13	14
7.1-14	14
7.1-15	14
7.1-16	14
7.1-17	14
7.1-18	14
7.1-19	14
7.1-20	14
7.1-21	14
7.1-22	14
7.1-23	14
7.1-24	14
7.1-25	14
7.1-27	14
7.1-28	14
7.1-29	14
7.1-30	14
7.1-31	14
7.1-32	14
7.1-33	14
7.1-34	14
7.1-35	14
7.1-36	14
7.1-37	14
7.1-38	14
7.1-39	14
7.2-1	15
7.2-2	15
7.2-3	15
7.2-4	15
7.2-5	15
7.2-6	15
7.2-7	15
7.2-8	15
7.2-9	15
7.2-10	15
7.2-11	15
7.2-12	15
7.2-13	15
7.2-14	15
7.2-15	15
7.2-16	15
7.2-17	15
7.2-18	15
7.2-19	15
7.2-20	15
7.2-21	15
7.2-22	15
7.2-23	15

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
7.2-24	15	7.3-22	7	7.5-8	0	7.7-5	7
7.2-25	15	7.3-23	7	7.5-9	0	7.7-6	7
7.2-27	15	7.3-24	7	7.5-10	0	7.7-7	7
7.2-29	15	7.3-25	7	7.5-11	0	7.7-8	7
7.2-31	15	7.3-26	7	7.5-12	0	7.7-9	7
7.2-33	15	7.3-27	7	7.5-13	1	7.7-10	7
7.2-35	15	7.3-28	7	7.5-14	1	7.7-11	7
7.2-37	15	7.3-29	7	7.5-15	1	7.7-12	7
7.2-39	15	7.3-30	7	7.5-16	1	7.7-13	7
7.2-41	15	7.3-31	7	7.5-17	1	7.7-14	7
7.2-43	15	7.3-32	7	7.5-18	1	7.7-15	7
7.2-45	15	7.3-33	7	7.5-19	1	7.7-16	7
7.2-47	15	7.3-34	7	7.5-20	1	7.7-17	7
7.2-49	15	7.3-35	7	7.5-21	3	7.7-18	7
7.2-51	15	7.3-36	7	7.5-22	1	7.7-19	7
7.2-53	15	7.3-37	7	7.5-23	1	7.7-20	7
7.2-55	15	7.3-38	7	7.5-24	3	7.7-21	7
7.2-57	15	7.3-39	7	7.5-25	0	7.7-22	7
7.2-59	15	7.3-40	7	7.5-26	0	7.7-23	7
7.2-61	15			7.5-27	0	7.7-24	7
7.2-63	15	7.4-1	12	7.5-28	0	7.7-25	7
		7.4-2	12	7.5-29	0		
7.3-1	7	7.4-3	12	7.5-30	1		
7.3-2	7	7.4-4	12	7.5-31	1		
7.3-3	7	7.4-5	12	7.5-32	1	i	7
7.3-4	7	7.4-6	12	7.5-33	1	ii	7
7.3-5	7	7.4-7	12	7.5-34	3	iii	7
7.3-6	7	7.4-8	12	7.5-35	1		
7.3-7	7	7.4-9	12	7.5-36	1	8.1-1	0
7.3-8	7	7.4-10	12	7.5-37	1	8.1-2	0
7.3-9	7	7.4-11	12	7.5-38	0	8.1-3	0
7.3-10	7	7.4-12	12			8.1-4	3
7.3-11	7	7.4-13	12	7.6-1	12	8.1-5	0
7.3-12	7	7.4-14	12	7.6-2	12	8.1-6	0
7.3-13	7	7.4-15	12	7.6-3	12	8.1-7	0
7.3-14	7			7.6-4	12	8.1-8	0
7.3-15	7	7.5-1	0	7.6.5	12	8.1-9	0
7.3-16	7	7.5-2	0	7.6-6	12	8.1-10	0
7.3-17	7	7.5-3	0				
7.3-18	7	7.5-4	0	7.7-1	7	8.2-1	7
7.3-19	7	7.5-5	0	7.7-2	7	8.2-2	7
7.3-20	7	7.5-6	1	7.7-3	7	8.2-3	7
7.3-21	7	7.5-7	0	7.7-4	7	8.2-4	7

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
8.3-1	11	8.3-44	11	9.1-9	15	9.1-52	15
8.3-2	11	8.3-45	11	9.1-10	15	9.1-53	15
8.3-3	11	8.3-46	11	9.1-11	15	9.1-54	15
8.3-4	11	8.3-47	11	9.1-12	15	9.1-55	15
8.3-5	11	8.3-48	11	9.1-13	15	9.1-56	15
8.3-6	11	8.3-49	11	9.1-14	15	9.1-57	15
8.3-7	11	8.3-50	11	9.1-15	15	9.1-58	15
8.3-8	11	8.3-51	11	9.1-16	15	9.1-59	15
8.3-9	11	8.3-53	11	9.1-17	15	9.1-60	15
8.3-10	11	8.3-55	11	9.1-18	15	9.1-61	15
8.3-11	11	8.3-57	11	9.1-19	15	9.1-63	15
8.3-12	11	8.3-59	11	9.1-20	15		
8.3-13	11	8.3-61	11	9.1-21	15	9.2-1	11
8.3-14	11	8.3-63	11	9.1-22	15	9.2-2	11
8.3-15	11	8.3-65	11	9.1-23	15	9.2-3	11
8.3-16	11	8.3-67	11	9.1-24	15	9.2-4	11
8.3-17	11	8.3-69	11	9.1-25	15	9.2-5	11
8.3-18	11	8.3-71	11	9.1-26	15	9.2-6	11
8.3-19	11	8.3-73	11	9.1-27	15	9.2-7	11
8.3-20	11			9.1-28	15	9.2-8	11
8.3-21	11			9.1-29	15	9.2-9	11
8.3-22	11			9.1-30	15	9.2-10	11
8.3-23	11	i	15	9.1-31	15	9.2-11	11
8.3-24	11	ii	15	9.1-32	15	9.2-12	11
8.3-25	11	iii	15	9.1-33	15	9.2-13	11
8.3-26	11	iv	15	9.1-34	15	9.2-14	11
8.3-27	11	v	15	9.1-35	15	9.2-15	11
8.3-28	11	vi	15	9.1-36	15	9.2-16	11
8.3-29	11	vii	15	9.1-37	15	9.2-17	11
8.3-30	11	viii	15	9.1-38	15	9.2-18	11
8.3-31	11	ix	15	9.1-39	15	9.2-19	11
8.3-32	11	x	15	9.1-40	15	9.2-20	11
8.3-33	11	xi	15	9.1-41	15	9.2-21	11
8.3-34	11	xii	15	9.1-42	15	9.2-22	11
8.3-35	11			9.1-43	15	9.2-23	11
8.3-36	11	9.1-1	15	9.1-44	15	9.2-24	11
8.3-37	11	9.1-2	15	9.1-45	15	9.2-25	11
8.3-38	11	9.1-3	15	9.1-46	15	9.2-26	11
8.3-39	11	9.1-4	15	9.1-47	15	9.2-27	11
8.3-40	11	9.1-5	15	9.1-48	15	9.2-28	11
8.3-41	11	9.1-6	15	9.1-49	15	9.2-29	11
8.3-42	11	9.1-7	15	9.1-50	15	9.2-30	11
8.3-43	11	9.1-8	15	9.1-51	15	9.2-31	11

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
9.2-32	11	9.3-9	8	9.3-52	8	9.4-27	12
9.2-33	11	9.3-10	8	9.3-53	8	9.4-28	12
9.2-34	11	9.3-11	8	9.3-54	8	9.4-29	12
9.2-35	11	9.3-12	8	9.3-55	8	9.4-30	12
9.2-36	11	9.3-13	8	9.3-56	8	9.4-31	12
9.2-37	11	9.3-14	8	9.3-57	8	9.4-32	12
9.2-38	11	9.3-15	8	9.3-58	8	9.4-33	12
9.2-39	11	9.3-16	8	9.3-59	8	9.4-34	12
9.2-40	11	9.3-17	8	9.3-60	8	9.4-35	12
9.2-41	11	9.3-18	8	9.3-61	8	9.4-36	12
9.2-42	11	9.3-19	8	9.3-63	8	9.4-37	12
9.2-43	11	9.3-20	8	9.3-65	8	9.4-38	12
9.2-44	11	9.3-21	8	9.3-67	8	9.4-39	12
9.2-45	11	9.3-22	8	9.3-69	8	9.4-40	12
9.2-46	11	9.3-23	8	9.3-71	8	9.4-41	12
9.2-47	11	9.3-24	8	9.3-73	8	9.4-42	12
9.2-48	11	9.3-25	8			9.4-43	12
9.2-49	11	9.3-26	8	9.4-1	12	9.4-44	12
9.2-50	11	9.3-27	8	9.4-2	12	9.4-45	12
9.2-51	11	9.3-28	8	9.4-3	12	9.4-46	12
9.2-52	11	9.3-29	8	9.4-4	12	9.4-47	12
9.2-53	11	9.3-30	8	9.4-5	12	9.4-48	12
9.2-54	11	9.3-31	8	9.4-6	12	9.4-49	12
9.2-55	11	9.3-32	8	9.4-7	12	9.4-50	12
9.2-57	11	9.3-33	8	9.4-8	12	9.4-51	12
9.2-59	11	9.3-34	8	9.4-9	12	9.4-52	12
9.2-61	11	9.3-35	8	9.4-10	12	9.4-53	12
9.2-63	11	9.3-36	8	9.4-11	12	9.4-54	12
9.2-65	11	9.3-37	8	9.4-12	12	9.4-55	12
9.2-67	11	9.3-38	8	9.4-13	12	9.4-56	12
9.2-69	11	9.3-39	8	9.4-14	12	9.4-57	12
9.2-71	11	9.3-40	8	9.4-15	12	9.4-58	12
9.2-73	11	9.3-41	8	9.4-16	12	9.4-59	12
9.2-75	11	9.3-42	8	9.4-17	12	9.4-60	12
		9.3-43	8	9.4-18	12	9.4-61	12
9.3-1	8	9.3-44	8	9.4-19	12	9.4-62	12
9.3-2	8	9.3-45	8	9.4-20	12	9.4-63	12
9.3-3	8	9.3-46	8	9.4-21	12	9.4-64	12
9.3-4	8	9.3-47	8	9.4-22	12	9.4-65	12
9.3-5	8	9.3-48	8	9.4-23	12	9.4-66	12
9.3-6	8	9.3-49	8	9.4-24	12	9.4-67	12
9.3-7	8	9.3-50	8	9.4-25	12	9.4-68	12
9.3-8	8	9.3-51	8	9.4-26	12	9.4-69	12

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
9.4-70	12	9.4-124	12	9.5-39	15	9A-3	15
9.4-71	12	9.4-125	12	9.5-40	15	9A-4	15
9.4-72	12	9.4-127	12	9.5-41	15	9A-5	15
9.4-73	12	9.4-129	12	9.5-42	15	9A-6	15
9.4-74	12			9.5-43	15	9A-7	15
9.4-75	12	9.5-1	15	9.5-44	15	9A-8	15
9.4-76	12	9.5-2	15	9.5-45	15	9A-9	15
9.4-77	12	9.5-3	15	9.5-46	15	9A-10	15
9.4-78	12	9.5-4	15	9.5-47	15	9A-11	15
9.4-79	12	9.5-5	15	9.5-48	15	9A-12	15
9.4-80	12	9.5-6	15	9.5-49	15	9A-13	15
9.4-81	12	9.5-7	15	9.5-50	15	9A-14	15
9.4-82	12	9.5-8	15	9.5-51	15	9A-15	15
9.4-83	12	9.5-9	15	9.5-52	15	9A-16	15
9.4-84	12	9.5-10	15	9.5-53	15	9A-17	15
9.4-85	12	9.5-11	15	9.5-54	15	9A-18	15
9.4-86	12	9.5-12	15	9.5-55	15	9A-19	15
9.4-87	12	9.5-13	15	9.5-56	15	9A-20	15
9.4-88	12	9.5-14	15	9.5-57	15	9A-21	15
9.4-89	12	9.5-15	15	9.5-58	15	9A-22	15
9.4-90	12	9.5-16	15	9.5-59	15	9A-23	15
9.4-91	12	9.5-17	15	9.5-60	15	9A-24	15
9.4-92	12	9.5-18	15	9.5-61	15	9A-25	15
9.4-93	12	9.5-19	15	9.5-62	15	9A-26	15
9.4-95	12	9.5-20	15	9.5-63	15	9A-27	15
9.4-97	12	9.5-21	15	9.5-64	15	9A-28	15
9.4-99	12	9.5-22	15	9.5-65	15	9A-29	15
9.4-101	12	9.5-23	15	9.5-66	15	9A-30	15
9.4-103	12	9.5-24	15	9.5-67	15	9A-31	15
9.4-104	12	9.5-25	15	9.5-68	15	9A-32	15
9.4-105	12	9.5-26	15	9.5-69	15	9A-33	15
9.4-107	12	9.5-27	15	9.5-70	15	9A-34	15
9.4-109	12	9.5-28	15	9.5-71	15	9A-35	15
9.4-110	12	9.5-29	15	9.5-72	15	9A-36	15
9.4-111	12	9.5-30	15	9.5-73	15	9A-37	15
9.4-112	12	9.5-31	15	9.5-75	15	9A-38	15
9.4-113	12	9.5-32	15	9.5-77	15	9A-39	15
9.4-115	12	9.5-33	15	9.5-79	15	9A-40	15
9.4-116	12	9.5-34	15	9.5-81	15	9A-41	15
9.4-117	12	9.5-35	15	9.5-83	15	9A-42	15
9.4-119	12	9.5-36	15			9A-43	15
9.4-121	12	9.5-37	15	9A-1	15	9A-44	15
9.4-123	12	9.5-38	15	9A-2	15	9A-45	15

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
9A-46	15	9A-89	15	9A-132	15	9A-185	15
9A-47	15	9A-90	15	9A-133	15	9A-187	15
9A-48	15	9A-91	15	9A-134	15	9A-189	15
9A-49	15	9A-92	15	9A-135	15	9A-191	15
9A-50	15	9A-93	15	9A-136	15	9A-193	15
9A-51	15	9A-94	15	9A-137	15	9A-195	15
9A-52	15	9A-95	15	9A-138	15	9A-197	15
9A-53	15	9A-96	15	9A-139	15	9A-199	15
9A-54	15	9A-97	15	9A-140	15	9A-201	15
9A-55	15	9A-98	15	9A-141	15	9A-203	15
9A-56	15	9A-99	15	9A-142	15	9A-205	15
9A-57	15	9A-100	15	9A-143	15	9A-207	15
9A-58	15	9A-101	15	9A-144	15	9A-209	15
9A-59	15	9A-102	15	9A-145	15	9A-211	15
9A-60	15	9A-103	15	9A-146	15	9A-213	15
9A-61	15	9A-104	15	9A-147	15		
9A-62	15	9A-105	15	9A-148	15		
9A-63	15	9A-106	15	9A-149	15		
9A-64	15	9A-107	15	9A-150	15	i	7
9A-65	15	9A-108	15	9A-151	15	ii	7
9A-66	15	9A-109	15	9A-152	15	iii	7
9A-67	15	9A-110	15	9A-153	15	iv	7
9A-68	15	9A-111	15	9A-154	15	v	7
9A-69	15	9A-112	15	9A-155	15	vi	7
9A-70	15	9A-113	15	9A-156	15		
9A-71	15	9A-114	15	9A-157	15	10.1-1	3
9A-72	15	9A-115	15	9A-158	15	10.1-2	0
9A-73	15	9A-116	15	9A-159	15	10.1-3	0
9A-74	15	9A-117	15	9A-160	15	10.1-4	1
9A-75	15	9A-118	15	9A-161	15	10.1-5	1
9A-76	15	9A-119	15	9A-162	15		
9A-77	15	9A-120	15	9A-163	15	10.2-1	7
9A-78	15	9A-121	15	9A-164	15	10.2-2	7
9A-79	15	9A-122	15	9A-165	15	10.2-3	7
9A-80	15	9A-123	15	9A-167	15	10.2-4	7
9A-81	15	9A-124	15	9A-169	15	10.2-5	7
9A-82	15	9A-125	15	9A-171	15	10.2-6	7
9A-83	15	9A-126	15	9A-173	15	10.2-7	7
9A-84	15	9A-127	15	9A-175	15	10.2-8	7
9A-85	15	9A-128	15	9A-177	15	10.2-9	7
9A-86	15	9A-129	15	9A-179	15	10.2-10	7
9A-87	15	9A-130	15	9A-181	15	10.2-11	7
9A-88	15	9A-131	15	9A-183	15	10.2-12	7

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
10.2-13	7	10.3-29	0	10.4-32	14	i	10
10.2-14	7	10.3-30	0	10.4-33	14	ii	10
10.2-15	7	10.3-31	0	10.4-34	14	iii	10
10.2-16	7	10.3-32	0	10.4-35	14	iv	10
10.2-17	7	10.3-33	0	10.4-36	14	v	10
10.2-18	7	10.3-34	0	10.4-37	14		
10.2-19	7	10.3-35	0	10.4-38	14	11.1-1	0
10.2-20	7	10.3-36	0	10.4-39	14	11.1-2	0
10.2-21	7	10.3-37	0	10.4-40	14	11.1-3	0
10.2-22	7	10.3-39	0	10.4-41	14	11.1-4	0
10.2-23	7	10.3-41	0	10.4-42	14	11.1-5	0
10.2-24	7			10.4-43	14	11.1-6	0
10.2-25	7	10.4-1	14	10.4-44	14	11.1-7	1
10.2-27	7	10.4-2	14	10.4-45	14	11.1-8	0
		10.4-3	14	10.4-46	14	11.1-9	0
10.3-1	0	10.4-4	14	10.4-47	14	11.1-10	1
10.3-2	0	10.4-5	14	10.4-48	14	11.1-11	1
10.3-3	0	10.4-6	14	10.4-49	14	11.1-12	0
10.3-4	0	10.4-7	14	10.4-50	14	11.1-13	0
10.3-5	0	10.4-8	14	10.4-51	14	11.1-14	0
10.3-6	0	10.4-9	14	10.4-52	14	11.1-15	1
10.3-7	0	10.4-10	14	10.4-53	14	11.1-16	0
10.3-8	0	10.4-11	14	10.4-54	14		
10.3-9	0	10.4-12	14	10.4-55	14	11.2-1	10
10.3-10	0	10.4-13	14	10.4-56	14	11.2-2	10
10.3-11	0	10.4-14	14	10.4-57	14	11.2-3	10
10.3-12	0	10.4-15	14	10.4-58	14	11.2-4	10
10.3-13	0	10.4-16	14	10.4-59	14	11.2-5	10
10.3-14	0	10.4-17	14	10.4-60	14	11.2-6	10
10.3-15	0	10.4-18	14	10.4-61	14	11.2-7	10
10.3-16	1	10.4-19	14	10.4-62	14	11.2-8	10
10.3-17	0	10.4-20	14	10.4-63	14	11.2-9	10
10.3-18	0	10.4-21	14	10.4-64	14	11.2-10	10
10.3-19	0	10.4-22	14	10.4-65	14	11.2-11	10
10.3-20	0	10.4-23	14	10.4-67	14	11.2-12	10
10.3-21	0	10.4-24	14	10.4-68	14	11.2-13	10
10.3-22	0	10.4-25	14	10.4-69	14	11.2-14	10
10.3-23	0	10.4-26	14	10.4-71	14	11.2-15	10
10.3-24	0	10.4-27	14	10.4-73	14	11.2-16	10
10.3-25	0	10.4-28	14	10.4-75	14	11.2-17	10
10.3-26	0	10.4-29	14	10.4-77	14	11.2-18	10
10.3-27	0	10.4-30	14			11.2-19	10
10.3-28	0	10.4-31	14			11.2-20	10

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
11.2-21	10	11.3-15	0	11.5-1	0	12.1-4	8
11.2-22	10	11.3-16	0	11.5-2	0	12.1-5	8
11.2-23	10	11.3-17	0	11.5-3	0	12.1-6	8
11.2-24	10	11.3-18	0	11.5-4	0		
11.2-25	10	11.3-19	0	11.5-5	0	12.2-1	0
11.2-26	10	11.3-20	0	11.5-6	0	12.2-2	0
11.2-27	10	11.3-21	1	11.5-7	0	12.2-3	0
11.2-28	10			11.5-8	0	12.2-4	1
11.2-29	10	11.4-1	0	11.5-9	0	12.2-5	1
11.2-30	10	11.4-2	0	11.5-10	0	12.2-6	0
11.2-31	10	11.4-3	0	11.5-11	0	12.2-7	0
11.2-32	10	11.4-4	0	11.5-12	0	12.2-8	0
11.2-33	10	11.4-5	0	11.5-13	4	12.2-9	3
11.2-34	10	11.4-6	0	11.5-14	4	12.2-10	1
11.2-35	10	11.4-7	0	11.5-15	0	12.2-11	1
11.2-36	10	11.4-8	0	11.5-16	0	12.2-12	0
11.2-37	10	11.4-9	0	11.5-17	0	12.2-13	1
11.2-38	10	11.4-10	0	11.5-18	0	12.2-14	0
11.2-39	10	11.4-11	0	11.5-19	0	12.2-15	0
11.2-40	10	11.4-12	0	11.5-20	0	12.2-16	0
11.2-41	10	11.4-13	0	11.5-21	0	12.2-17	0
11.2-42	10	11.4-14	3	11.5-22	0	12.2-18	0
11.2-43	10	11.4-15	4	11.5-23	0	12.2-19	0
11.2-45	10	11.4-16	1	11.5-24	0	12.2-20	0
11.2-47	10	11.4-17	1	11.5-25	0	12.2-21	0
11.2-49	10	11.4-18	1	11.5-26	0	12.2-22	0
11.2-51	10	11.4-19	1	11.5-27	0	12.2-23	0
11.2-53	10	11.4-20	1	11.5-28	0	12.2-24	0
		11.4-21	1	11.5-29	0	12.2-25	0
11.3-1	3	11.4-22	1			12.2-26	0
11.3-2	0	11.4-23	1			12.2-27	1
11.3-3	0	11.4-24	1			12.2-28	1
11.3-4	0	11.4-25	1	i	0	12.2-29	1
11.3-5	0	11.4-26	0	ii	0	12.2-30	1
11.3-6	0	11.4-27	1	iii	0	12.2-31	1
11.3-7	0	11.4-28	1	iv	0	12.2-32	0
11.3-8	0	11.4-29	1	v	0	12.2-33	0
11.3-9	0	11.4-30	1	vi	0	12.2-34	0
11.3-10	0	11.4-31	1	vii	0	12.2-35	1
11.3-11	0	11.4-32	0			12.2-36	1
11.3-12	0	11.4-33	0	12.1-1	8	12.2-37	1
11.3-13	0	11.4-34	0	12.1-2	8	12.2-38	1
11.3-14	0	11.4-35	0	12.1-3	8	12.2-39	1

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision
12.2-40	0
12.2-41	0
12.2-42	0
12.2-43	0
12.2-44	0
12.2-45	1
12.2-46	0
12.2-47	0
12.2-48	0
12.2-49	1
12.2-50	1
12.2-51	1
12.2-52	1
12.2-53	0
12.2-54	0
12.2-55	0
12.2-56	0
12.2-57	0
12.2-58	0
12.2-59	0
12.2-60	0
12.2-61	0
12.2-62	0
12.2-63	0
12.3-1	9
12.3-2	9
12.3-3	9
12.3-4	9
12.3-5	9
12.3-6	9
12.3-7	9
12.3-8	9
12.3-9	9
12.3-10	9
12.3-11	9
12.3-12	9
12.3-13	9
12.3-14	9
12.3-15	9
12.3-16	9
12.3-17	9
12.3-18	9
12.3-19	9
12.3-20	9
12.3-21	9
12.3-22	9
12.3-23	9
12.3-25	9
12.3-27	9
12.3-29	9
12.3-31	9
12.3-33	9
12.3-35	9
12.3-37	9
12.3-39	9
12.3-41	9
12.3-43	9
12.3-45	9
12.3-47	9
12.3-49	9
12.3-51	9
12.3-53	9
12.3-54	9
12.3-55	9
12.3-57	9
12.3-59	9
12.3-61	9
12.3-63	9
12.3-65	9
12.3-67	9
12.3-69	9
12.3-71	9
12.3-73	9
12.3-75	9
12.3-77	9
12.3-79	9
12.3-81	9
12.3-83	9
12.3-84	9
12.3-85	9
12.3-87	9
12.3-89	9
12.3-91	9
12.3-93	9
12.3-95	9
12.3-97	9
12.3-99	9
12.3-101	9
12.3-103	9
12.3-105	9
12.3-107	9
12.3-109	9
12.3-111	9
12.3-113	9
12.4-1	0
12.4-2	0
12.4-3	0
12.4-4	3
12.4-5	0
12.4-6	0
12.4-7	0
12.4-8	0
12.4-9	0
12.4-10	0
12.4-11	3
12.4-12	3
12.4-13	3
12.4-14	1
12.4-15	0
12.4-16	0
12.4-17	0
12.4-18	0
12.4-19	0
12.5-1	0
12.5-2	0
12.5-3	0
12.5-4	0
i	11
13-1	14
13-2	14
13-3	14
13-4	14
13-5	14
13-6	14
13-7	14
13-8	14
i	7
ii	7
iii	7
iv	7
v	7
vi	7
14.1-1	3
14.2-1	15
14.2-2	15
14.2-3	15
14.2-4	15
14.2-5	15
14.2-6	15
14.2-7	15
14.2-8	15
14.2-9	15
14.2-10	15
14.2-11	15
14.2-12	15
14.2-13	15
14.2-14	15
14.2-15	15
14.2-16	15
14.2-17	15
14.2-18	15
14.2-19	15
14.2-20	15
14.2-21	15
14.2-22	15
14.2-23	15
14.2-24	15
14.2-25	15
14.2-26	15
14.2-27	15

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
14.2-28	15	14.2-71	15	14.2-114	15	14.3-22	11
14.2-29	15	14.2-72	15	14.2-115	15	14.3-23	11
14.2-30	15	14.2-73	15	14.2-116	15	14.3-24	11
14.2-31	15	14.2-74	15	14.2-117	15	14.3-25	11
14.2-32	15	14.2-75	15	14.2-118	15	14.3-26	11
14.2-33	15	14.2-76	15	14.2-119	15	14.3-27	11
14.2-34	15	14.2-77	15	14.2-120	15	14.3-28	11
14.2-35	15	14.2-78	15	14.2-121	15	14.3-29	11
14.2-36	15	14.2-79	15	14.2-122	15	14.3-30	11
14.2-37	15	14.2-80	15	14.2-123	15	14.3-31	11
14.2-38	15	14.2-81	15	14.2-124	15	14.3-32	11
14.2-39	15	14.2-82	15	14.2-125	15	14.3-33	11
14.2-40	15	14.2-83	15	14.2-126	15	14.3-34	11
14.2-41	15	14.2-84	15	14.2-127	15	14.3-35	11
14.2-42	15	14.2-85	15	14.2-128	15	14.3-36	11
14.2-43	15	14.2-86	15	14.2-129	15	14.3-37	11
14.2-44	15	14.2-87	15	14.2-130	15	14.3-38	11
14.2-45	15	14.2-88	15	14.2-131	15	14.3-39	11
14.2-46	15	14.2-89	15	14.2-132	15	14.3-40	11
14.2-47	15	14.2-90	15	14.2-133	15	14.3-41	11
14.2-48	15	14.2-91	15	14.2-134	15	14.3-42	11
14.2-49	15	14.2-92	15			14.3-43	11
14.2-50	15	14.2-93	15	14.3-1	11	14.3-44	11
14.2-51	15	14.2-94	15	14.3-2	11	14.3-45	11
14.2-52	15	14.2-95	15	14.3-3	11	14.3-46	11
14.2-53	15	14.2-96	15	14.3-4	11	14.3-47	11
14.2-54	15	14.2-97	15	14.3-5	11	14.3-48	11
14.2-55	15	14.2-98	15	14.3-6	11	14.3-49	11
14.2-56	15	14.2-99	15	14.3-7	11	14.3-50	11
14.2-57	15	14.2-100	15	14.3-8	11	14.3-51	11
14.2-58	15	14.2-101	15	14.3-9	11	14.3-52	11
14.2-59	15	14.2-102	15	14.3-10	11		
14.2-60	15	14.2-103	15	14.3-11	11	14.4-1	9
14.2-61	15	14.2-104	15	14.3-12	11	14.4-2	9
14.2-62	15	14.2-105	15	14.3-13	11		
14.2-63	15	14.2-106	15	14.3-14	11		
14.2-64	15	14.2-107	15	14.3-15	11		
14.2-65	15	14.2-108	15	14.3-16	11	i	11
14.2-66	15	14.2-109	15	14.3-17	11	ii	11
14.2-67	15	14.2-110	15	14.3-18	11	iii	11
14.2-68	15	14.2-111	15	14.3-19	11	iv	11
14.2-69	15	14.2-112	15	14.3-20	11	v	11
14.2-70	15	14.2-113	15	14.3-21	11	vi	11

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
vii	11	15.0-27	15	15.1-30	14	15.1-73	14
viii	11	15.0-28	15	15.1-31	14	15.1-74	14
ix	11	15.0-29	15	15.1-32	14	15.1-75	14
x	11	15.0-30	15	15.1-33	14	15.1-76	14
xi	11	15.0-31	15	15.1-34	14	15.1-77	14
xii	11	15.0-32	15	15.1-35	14	15.1-78	14
xiii	11	15.0-33	15	15.1-36	14	15.1-79	14
xiv	11	15.0-34	15	15.1-37	14	15.1-80	14
xv	11	15.0-35	15	15.1-38	14	15.1-81	14
xvi	11	15.0-36	15	15.1-39	14	15.1-82	14
xvii	11	15.0-37	15	15.1-40	14	15.1-83	14
xviii	11	15.0-38	15	15.1-41	14		
xix	11	15.0-39	15	15.1-42	14	15.2-1	14
xx	11			15.1-43	14	15.2-2	14
xxi	11	15.1-1	14	15.1-44	14	15.2-3	14
xxii	11	15.1-2	14	15.1-45	14	15.2-4	14
		15.1-3	14	15.1-46	14	15.2-5	14
15.0-1	15	15.1-4	14	15.1-47	14	15.2-6	14
15.0-2	15	15.1-5	14	15.1-48	14	15.2-7	14
15.0-3	15	15.1-6	14	15.1-49	14	15.2-8	14
15.0-4	15	15.1-7	14	15.1-50	14	15.2-9	14
15.0-5	15	15.1-8	14	15.1-51	14	15.2-10	14
15.0-6	15	15.1-9	14	15.1-52	14	15.2-11	14
15.0-7	15	15.1-10	14	15.1-53	14	15.2-12	14
15.0-8	15	15.1-11	14	15.1-54	14	15.2-13	14
15.0-9	15	15.1-12	14	15.1-55	14	15.2-14	14
15.0-10	15	15.1-13	14	15.1-56	14	15.2-15	14
15.0-11	15	15.1-14	14	15.1-57	14	15.2-16	14
15.0-12	15	15.1-15	14	15.1-58	14	15.2-17	14
15.0-13	15	15.1-16	14	15.1-59	14	15.2-18	14
15.0-14	15	15.1-17	14	15.1-60	14	15.2-19	14
15.0-15	15	15.1-18	14	15.1-61	14	15.2-20	14
15.0-16	15	15.1-19	14	15.1-62	14	15.2-21	14
15.0-17	15	15.1-20	14	15.1-63	14	15.2-22	14
15.0-18	15	15.1-21	14	15.1-64	14	15.2-23	14
15.0-19	15	15.1-22	14	15.1-65	14	15.2-24	14
15.0-20	15	15.1-23	14	15.1-66	14	15.2-25	14
15.0-21	15	15.1-24	14	15.1-67	14	15.2-26	14
15.0-22	15	15.1-25	14	15.1-68	14	15.2-27	14
15.0-23	15	15.1-26	14	15.1-69	14	15.2-28	14
15.0-24	15	15.1-27	14	15.1-70	14	15.2-29	14
15.0-25	15	15.1-28	14	15.1-71	14	15.2-30	14
15.0-26	15	15.1-29	14	15.1-72	14	15.2-31	14

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
15.2-32	14	15.2-75	14	15.3-31	15	15.4-39	14
15.2-33	14	15.2-76	14	15.3-32	15	15.4-40	14
15.2-34	14	15.2-77	14	15.3-33	15	15.4-41	14
15.2-35	14	15.2-78	14	15.3-34	15	15.4-42	14
15.2-36	14	15.2-79	14			15.4-43	14
15.2-37	14	15.2-80	14	15.4-1	14	15.4-44	14
15.2-38	14	15.2-81	14	15.4-2	14	15.4-45	14
15.2-39	14	15.2-82	14	15.4-3	14	15.4-46	14
15.2-40	14	15.2-83	14	15.4-4	14	15.4-47	14
15.2-41	14	15.2-84	14	15.4-5	14	15.4-48	14
15.2-42	14	15.2-85	14	15.4-6	14	15.4-49	14
15.2-43	14	15.2-86	14	15.4-7	14	15.4-50	14
15.2-44	14			15.4-8	14	15.4-51	14
15.2-45	14	15.3-1	15	15.4-9	14	15.4-52	14
15.2-46	14	15.3-2	15	15.4-10	14	15.4-53	14
15.2-47	14	15.3-3	15	15.4-11	14	15.4-54	14
15.2-48	14	15.3-4	15	15.4-12	14	15.4-55	14
15.2-49	14	15.3-5	15	15.4-13	14	15.4-56	14
15.2-50	14	15.3-6	15	15.4-14	14	15.4-57	14
15.2-51	14	15.3-7	15	15.4-15	14	15.4-58	14
15.2-52	14	15.3-8	15	15.4-16	14	15.4-59	14
15.2-53	14	15.3-9	15	15.4-17	14	15.4-60	14
15.2-54	14	15.3-10	15	15.4-18	14	15.4-61	14
15.2-55	14	15.3-11	15	15.4-19	14	15.4-62	14
15.2-56	14	15.3-12	15	15.4-20	14	15.4-63	14
15.2-57	14	15.3-13	15	15.4-21	14	15.4-64	14
15.2-58	14	15.3-14	15	15.4-22	14	15.4-65	14
15.2-59	14	15.3-15	15	15.4-23	14	15.4-66	14
15.2-60	14	15.3-16	15	15.4-24	14	15.4-67	14
15.2-61	14	15.3-17	15	15.4-25	14	15.4-68	14
15.2-62	14	15.3-18	15	15.4-26	14	15.4-69	14
15.2-63	14	15.3-19	15	15.4-27	14	15.4-70	14
15.2-64	14	15.3-20	15	15.4-28	14	15.4-71	14
15.2-65	14	15.3-21	15	15.4-29	14	15.4-72	14
15.2-66	14	15.3-22	15	15.4-30	14	15.4-73	14
15.2-67	14	15.3-23	15	15.4-31	14	15.4-74	14
15.2-68	14	15.3-24	15	15.4-32	14	15.4-75	14
15.2-69	14	15.3-25	15	15.4-33	14	15.4-76	14
15.2-70	14	15.3-26	15	15.4-34	14	15.4-77	14
15.2-71	14	15.3-27	15	15.4-35	14	15.4-78	14
15.2-72	14	15.3-28	15	15.4-36	14	15.4-79	14
15.2-73	14	15.3-29	15	15.4-37	14		
15.2-74	14	15.3-30	15	15.4-38	14		

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
15.5-1	1	15.6-9	14	15.6-52	14	15.6-95	14
15.5-2	1	15.6-10	14	15.6-53	14	15.6-96	14
15.5-3	1	15.6-11	14	15.6-54	14	15.6-97	14
15.5-4	1	15.6-12	14	15.6-55	14	15.6-98	14
15.5-5	1	15.6-13	14	15.6-56	14	15.6-99	14
15.5-6	1	15.6-14	14	15.6-57	14	15.6-100	14
15.5-7	1	15.6-15	14	15.6-58	14	15.6-101	14
15.5-8	1	15.6-16	14	15.6-59	14	15.6-102	14
15.5-9	1	15.6-17	14	15.6-60	14	15.6-103	14
15.5-10	1	15.6-18	14	15.6-61	14	15.6-104	14
15.5-11	1	15.6-19	14	15.6-62	14	15.6-105	14
15.5-12	1	15.6-20	14	15.6-63	14	15.6-106	14
15.5-13	1	15.6-21	14	15.6-64	14	15.6-107	14
15.5-14	1	15.6-22	14	15.6-65	14	15.6-108	14
15.5-15	1	15.6-23	14	15.6-66	14	15.6-109	14
15.5-16	1	15.6-24	14	15.6-67	14	15.6-110	14
15.5-17	1	15.6-25	14	15.6-68	14	15.6-111	14
15.5-18	1	15.6-26	14	15.6-69	14	15.6-112	14
15.5-19	1	15.6-27	14	15.6-70	14	15.6-113	14
15.5-20	1	15.6-28	14	15.6-71	14	15.6-114	14
15.5-21	1	15.6-29	14	15.6-72	14	15.6-115	14
15.5-22	1	15.6-30	14	15.6-73	14	15.6-116	14
15.5-23	1	15.6-31	14	15.6-74	14	15.6-117	14
15.5-24	1	15.6-32	14	15.6-75	14	15.6-118	14
15.5-25	1	15.6-33	14	15.6-76	14	15.6-119	14
15.5-26	1	15.6-34	14	15.6-77	14	15.6-120	14
15.5-27	1	15.6-35	14	15.6-78	14	15.6-121	14
15.5-28	1	15.6-36	14	15.6-79	14	15.6-122	14
15.5-29	1	15.6-37	14	15.6-80	14	15.6-123	14
15.5-30	1	15.6-38	14	15.6-81	14	15.6-124	14
15.5-31	1	15.6-39	14	15.6-82	14	15.6-125	14
15.5-32	1	15.6-40	14	15.6-83	14	15.6-126	14
15.5-33	1	15.6-41	14	15.6-84	14	15.6-127	14
15.5-34	1	15.6-42	14	15.6-85	14	15.6-128	14
		15.6-43	14	15.6-86	14	15.6-129	14
15.6-1	14	15.6-44	14	15.6-87	14	15.6-130	14
15.6-2	14	15.6-45	14	15.6-88	14	15.6-131	14
15.6-3	14	15.6-46	14	15.6-89	14	15.6-132	14
15.6-4	14	15.6-47	14	15.6-90	14	15.6-133	14
15.6-5	14	15.6-48	14	15.6-91	14	15.6-134	14
15.6-6	14	15.6-49	14	15.6-92	14	15.6-135	14
15.6-7	14	15.6-50	14	15.6-93	14	15.6-136	14
15.6-8	14	15.6-51	14	15.6-94	14	15.6-137	14

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
15.6-138	14	15.6-181	14	15.6-224	14	15.7-3	7
15.6-139	14	15.6-182	14	15.6-225	14	15.7-4	7
15.6-140	14	15.6-183	14	15.6-226	14	15.7-5	7
15.6-141	14	15.6-184	14	15.6-227	14	15.7-6	7
15.6-142	14	15.6-185	14	15.6-228	14		
15.6-143	14	15.6-186	14	15.6-229	14	15.8-1	1
15.6-144	14	15.6-187	14	15.6-230	14		
15.6-145	14	15.6-188	14	15.6-231	14	15A-1	12
15.6-146	14	15.6-189	14	15.6-232	14	15A-2	12
15.6-147	14	15.6-190	14	15.6-233	14	15A-3	12
15.6-148	14	15.6-191	14	15.6-234	14	15A-4	12
15.6-149	14	15.6-192	14	15.6-235	14	15A-5	12
15.6-150	14	15.6-193	14	15.6-236	14	15A-6	12
15.6-151	14	15.6-194	14	15.6-237	14	15A-7	12
15.6-152	14	15.6-195	14	15.6-238	14	15A-8	12
15.6-153	14	15.6-196	14	15.6-239	14	15A-9	12
15.6-154	14	15.6-197	14	15.6-240	14	15A-10	12
15.6-155	14	15.6-198	14	15.6-241	14	15A-11	12
15.6-156	14	15.6-199	14	15.6-242	14	15A-12	12
15.6-157	14	15.6-200	14	15.6-243	14	15A-13	12
15.6-158	14	15.6-201	14	15.6-244	14	15A-14	12
15.6-159	14	15.6-202	14	15.6-245	14	15A-15	12
15.6-160	14	15.6-203	14	15.6-246	14	15A-16	12
15.6-161	14	15.6-204	14	15.6-247	14	15A-17	12
15.6-162	14	15.6-205	14	15.6-248	14	15A-18	12
15.6-163	14	15.6-206	14	15.6-249	14		
15.6-164	14	15.6-207	14	15.6-250	14	15B-1	12
15.6-165	14	15.6-208	14	15.6-251	14	15B-2	12
15.6-166	14	15.6-209	14	15.6-252	14	15B-3	12
15.6-167	14	15.6-210	14	15.6-253	14	15B-4	12
15.6-168	14	15.6-211	14	15.6-254	14	15B-5	12
15.6-169	14	15.6-212	14	15.6-255	14	15B-6	12
15.6-170	14	15.6-213	14	15.6-256	14	15B-7	12
15.6-171	14	15.6-214	14	15.6-257	14	15B-8	12
15.6-172	14	15.6-215	14	15.6-258	14	15B-9	12
15.6-173	14	15.6-216	14	15.6-259	14	15B-10	12
15.6-174	14	15.6-217	14	15.6-260	14	15B-11	12
15.6-175	14	15.6-218	14	15.6-261	14	15B-12	12
15.6-176	14	15.6-219	14	15.6-262	14		
15.6-177	14	15.6-220	14	15.6-263	14		
15.6-178	14	15.6-221	14				
15.6-179	14	15.6-222	14	15.7-1	7	i	7
15.6-180	14	15.6-223	14	15.7-2	7	ii	7

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
3.5.4-1	3	3.7.5-1	3	5.3-1	3	B 3.0-13	3
3.5.4-2	3	3.7.6-1	3	5.4-1	3	B 3.0-14	3
3.5.4-3	4	3.7.6-2	3	5.5-1	8	B 3.0-15	3
3.5.5-1	4	3.7.6-3	3	5.5-2	8	B 3.0-16	3
3.5.5-2	3	3.7.7-1	3	5.5-3	8	B 3.0-17	3
3.5.6-1	8	3.7.7-2	3	5.5-4	8	B 3.0-18	3
3.5.6-2	8	3.7.8-1	10	5.5-5	8	B 3.1.1-1	13
3.5.6-3	8	3.7.9-1	3	5.5-6	8	B 3.1.1-2	13
3.5.6-4	8	3.7.9-2	3	5.5-7	8	B 3.1.1-3	13
3.5.7-1	8	3.7.10-1	13	5.5-8	8	B 3.1.1-4	13
3.5.7-2	8	3.7.10-2	13	5.5-9	8	B 3.1.1-5	13
3.5.8-1	8	3.8.1-1	13	5.5-10	8	B 3.1.2-1	3
3.5.8-2	8	3.8.1-2	13	5.5-11	8	B 3.1.2-2	3
3.6.1-1	3	3.8.1-3	13	5.5-12	8	B 3.1.2-3	3
3.6.2-1	3	3.8.2-1	3	5.5-13	8	B 3.1.2-4	3
3.6.2-2	3	3.8.2-2	3	5.5-14	8	B 3.1.2-5	3
3.6.2-3	3	3.8.3-1	3	5.6-1	14	B 3.1.3-1	3
3.6.2-4	3	3.8.3-2	3	5.6-2	14	B 3.1.3-2	3
3.6.3-1	3	3.8.4-1	3	5.6-3	14	B 3.1.3-3	3
3.6.3-2	3	3.8.4-2	3	5.6-4	14	B 3.1.3-4	3
3.6.3-3	3	3.8.5-1	3	5.6-5	14	B 3.1.3-5	3
3.6.3-4	3	3.8.5-2	3	5.7-1	3	B 3.1.3-6	3
3.6.4-1	3	3.8.6-1	3	5.7-2	3	B 3.1.4-1	3
3.6.5-1	3	3.8.6-2	3	5.7-3	3	B 3.1.4-2	4
3.6.6-1	13	3.8.7-1	3	5.7-4	3	B 3.1.4-3	3
3.6.6-2	13	3.8.7-2	3	B 2.1.1-1	3	B 3.1.4-4	4
3.6.7-1	4	3.8.7-3	3	B 2.1.1-2	3	B 3.1.4-5	4
3.6.7-2	3	3.8.7-4	3	B 2.1.1-3	3	B 3.1.4-6	3
3.6.8-1	3	3.9.1-1	4	B 2.1.2-1	3	B 3.1.4-7	3
3.6.8-2	3	3.9.2-1	3	B 2.1.2-2	3	B 3.1.4-8	3
3.6.8-3	3	3.9.3-1	3	B 2.1.2-3	3	B 3.1.4-9	3
3.6.9-1	3	3.9.3-2	3	B 3.0-1	3	B 3.1.4-10	3
3.7.1-1	3	3.9.4-1	3	B 3.0-2	3	B 3.1.5-1	3
3.7.1-2	3	3.9.5-1	13	B 3.0-3	3	B 3.1.5-2	3
3.7.1-3	3	3.9.5-2	13	B 3.0-4	3	B 3.1.5-3	3
3.7.1-4	3	3.9.6-1	3	B 3.0-5	3	B 3.1.5-4	3
3.7.2-1	13	3.9.7-1	13	B 3.0-6	3	B 3.1.6-1	4
3.7.2-2	13	3.9.7-2	13	B 3.0-7	3	B 3.1.6-2	3
3.7.2-3	13	4.0-1	3	B 3.0-8	3	B 3.1.6-3	3
3.7.2-4	13	4.0-2	3	B 3.0-9	4	B 3.1.6-4	3
3.7.3-1	4	5.1-1	3	B 3.0-10	4	B 3.1.6-5	3
3.7.3-2	4	5.2-1	3	B 3.0-11	3	B 3.1.7-1	3
3.7.4-1	3	5.2-2	3	B 3.0-12	3	B 3.1.7-2	3

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
B 3.1.7-3	3	B 3.2.5-2	3	B 3.3.1-40	15	B 3.3.2-35	14
B 3.1.7-4	4	B 3.2.5-3	3	B 3.3.1-41	15	B 3.3.2-36	14
B 3.1.7-5	3	B 3.2.5-4	3	B 3.3.1-42	15	B 3.3.2-37	14
B 3.1.7-6	3	B 3.2.5-5	3	B 3.3.1-43	15	B 3.3.2-38	14
B 3.1.8-1	3	B 3.3.1-1	15	B 3.3.1-44	15	B 3.3.2-39	14
B 3.1.8-2	3	B 3.3.1-2	15	B 3.3.1-45	15	B 3.3.2-40	14
B 3.1.8-3	3	B 3.3.1-3	15	B 3.3.1-46	15	B 3.3.2-41	14
B 3.1.8-4	3	B 3.3.1-4	15	B 3.3.1-47	15	B 3.3.2-42	14
B 3.1.8-5	3	B 3.3.1-5	15	B 3.3.1-48	15	B 3.3.2-43	14
B 3.1.8-6	3	B 3.3.1-6	15	B 3.3.2-1	14	B 3.3.2-44	14
B 3.1.8-7	3	B 3.3.1-7	15	B 3.3.2-2	14	B 3.3.2-45	14
B 3.1.9-1	3	B 3.3.1-8	15	B 3.3.2-3	14	B 3.3.2-46	14
B 3.1.9-2	3	B 3.3.1-9	15	B 3.3.2-4	14	B 3.3.2-47	14
B 3.1.9-3	3	B 3.3.1-10	15	B 3.3.2-5	14	B 3.3.2-48	14
B 3.2.1-1	14	B 3.3.1-11	15	B 3.3.2-6	14	B 3.3.2-49	14
B 3.2.1-2	14	B 3.3.1-12	15	B 3.3.2-7	14	B 3.3.2-50	14
B 3.2.1-3	14	B 3.3.1-13	15	B 3.3.2-8	14	B 3.3.2-51	14
B 3.2.1-4	14	B 3.3.1-14	15	B 3.3.2-9	14	B 3.3.2-52	14
B 3.2.1-5	14	B 3.3.1-15	15	B 3.3.2-10	14	B 3.3.2-53	14
B 3.2.1-6	14	B 3.3.1-16	15	B 3.3.2-11	14	B 3.3.2-54	14
B 3.2.1-7	14	B 3.3.1-17	15	B 3.3.2-12	14	B 3.3.2-55	14
B 3.2.1-8	14	B 3.3.1-18	15	B 3.3.2-13	14	B 3.3.2-56	14
B 3.2.1-9	14	B 3.3.1-19	15	B 3.3.2-14	14	B 3.3.2-57	14
B 3.2.1-10	14	B 3.3.1-20	15	B 3.3.2-15	14	B 3.3.2-58	14
B 3.2.2-1	3	B 3.3.1-21	15	B 3.3.2-16	14	B 3.3.2-59	14
B 3.2.2-2	3	B 3.3.1-22	15	B 3.3.2-17	14	B 3.3.2-60	14
B 3.2.2-3	3	B 3.3.1-23	15	B 3.3.2-18	14	B 3.3.2-61	14
B 3.2.2-4	3	B 3.3.1-24	15	B 3.3.2-19	14	B 3.3.2-62	14
B 3.2.2-5	3	B 3.3.1-25	15	B 3.3.2-20	14	B 3.3.2-63	14
B 3.2.2-6	3	B 3.3.1-26	15	B 3.3.2-21	14	B 3.3.2-64	14
B 3.2.2-7	3	B 3.3.1-27	15	B 3.3.2-22	14	B 3.3.2-65	14
B 3.2.3-1	14	B 3.3.1-28	15	B 3.3.2-23	14	B 3.3.2-66	14
B 3.2.3-2	14	B 3.3.1-29	15	B 3.3.2-24	14	B 3.3.2-67	14
B 3.2.3-3	14	B 3.3.1-30	15	B 3.3.2-25	14	B 3.3.2-68	14
B 3.2.3-4	14	B 3.3.1-31	15	B 3.3.2-26	14	B 3.3.3-1	3
B 3.2.3-5	14	B 3.3.1-32	15	B 3.3.2-27	14	B 3.3.3-2	4
B 3.2.4-1	3	B 3.3.1-33	15	B 3.3.2-28	14	B 3.3.3-3	3
B 3.2.4-2	3	B 3.3.1-34	15	B 3.3.2-29	14	B 3.3.3-4	3
B 3.2.4-3	3	B 3.3.1-35	15	B 3.3.2-30	14	B 3.3.3-5	3
B 3.2.4-4	3	B 3.3.1-36	15	B 3.3.2-31	14	B 3.3.3-6	3
B 3.2.4-5	3	B 3.3.1-37	15	B 3.3.2-32	14	B 3.3.3-7	3
B 3.2.4-6	3	B 3.3.1-38	15	B 3.3.2-33	14	B 3.3.3-8	3
B 3.2.5-1	3	B 3.3.1-39	15	B 3.3.2-34	14	B 3.3.3-9	3

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
B 3.3.4-1	3	B 3.4.8-2	3	B 3.4.17-3	3	B 3.6.1-4	3
B 3.3.4-2	3	B 3.4.8-3	3	B 3.5.1-1	8	B 3.6.2-1	3
B 3.3.4-3	3	B 3.4.8-4	3	B 3.5.1-2	8	B 3.6.2-2	3
B 3.3.4-4	3	B 3.4.9-1	10	B 3.5.1-3	8	B 3.6.2-3	3
B 3.3.5-1	7	B 3.4.9-2	10	B 3.5.1-4	8	B 3.6.2-4	3
B 3.3.5-2	7	B 3.4.9-3	10	B 3.5.1-5	8	B 3.6.2-5	3
B 3.3.5-3	7	B 3.4.9-4	10	B 3.5.1-6	8	B 3.6.2-6	3
B 3.3.5-4	7	B 3.4.9-5	10	B 3.5.1-7	8	B 3.6.2-7	3
B 3.3.5-5	7	B 3.4.9-6	10	B 3.5.2-1	8	B 3.6.3-1	3
B 3.4.1-1	3	B 3.4.9-7	10	B 3.5.2-2	8	B 3.6.3-2	3
B 3.4.1-2	3	B 3.4.10-1	4	B 3.5.2-3	8	B 3.6.3-3	4
B 3.4.1-3	3	B 3.4.10-2	3	B 3.5.2-4	8	B 3.6.3-4	3
B 3.4.1-4	3	B 3.4.10-3	3	B 3.5.2-5	8	B 3.6.3-5	3
B 3.4.2-1	3	B 3.4.10-4	3	B 3.5.2-6	8	B 3.6.3-6	3
B 3.4.2-2	3	B 3.4.11-1	13	B 3.5.2-7	8	B 3.6.3-7	3
B 3.4.2-3	3	B 3.4.11-2	13	B 3.5.2-8	8	B 3.6.3-8	3
B 3.4.3-1	3	B 3.4.11-3	13	B 3.5.3-1	3	B 3.6.3-9	3
B 3.4.3-2	3	B 3.4.11-4	13	B 3.5.3-2	4	B 3.6.4-1	8
B 3.4.3-3	3	B 3.4.12-1	13	B 3.5.3-3	3	B 3.6.4-2	8
B 3.4.3-4	3	B 3.4.12-2	13	B 3.5.4-1	3	B 3.6.4-3	8
B 3.4.3-5	3	B 3.4.12-3	13	B 3.5.4-2	4	B 3.6.5-1	3
B 3.4.3-6	3	B 3.4.12-4	13	B 3.5.4-3	4	B 3.6.5-2	3
B 3.4.3-7	3	B 3.4.13-1	3	B 3.5.4-4	4	B 3.6.5-3	3
B 3.4.4-1	11	B 3.4.13-2	4	B 3.5.4-5	3	B 3.6.6-1	13
B 3.4.4-2	11	B 3.4.13-3	4	B 3.5.4-6	4	B 3.6.6-2	13
B 3.4.4-3	11	B 3.4.14-1	8	B 3.5.5-1	4	B 3.6.6-3	13
B 3.4.4-4	11	B 3.4.14-2	8	B 3.5.5-2	4	B 3.6.6-4	13
B 3.4.4-5	11	B 3.4.14-3	8	B 3.5.5-3	3	B 3.6.6-5	13
B 3.4.4-6	11	B 3.4.14-4	8	B 3.5.6-1	8	B 3.6.6-6	13
B 3.4.5-1	3	B 3.4.14-5	8	B 3.5.6-2	8	B 3.6.6-7	13
B 3.4.5-2	3	B 3.4.14-6	8	B 3.5.6-3	8	B 3.6.7-1	3
B 3.4.5-3	3	B 3.4.14-7	8	B 3.5.6-4	8	B 3.6.7-2	3
B 3.4.6-1	3	B 3.4.14-8	8	B 3.5.6-5	8	B 3.6.7-3	4
B 3.4.6-2	3	B 3.4.15-1	3	B 3.5.6-6	8	B 3.6.8-1	13
B 3.4.6-3	3	B 3.4.15-2	3	B 3.5.7-1	8	B 3.6.8-2	13
B 3.4.6-4	3	B 3.4.15-3	4	B 3.5.7-2	8	B 3.6.8-3	13
B 3.4.7-1	3	B 3.4.15-4	3	B 3.5.7-3	8	B 3.6.8-4	13
B 3.4.7-2	3	B 3.4.15-5	3	B 3.5.8-1	8	B 3.6.8-5	13
B 3.4.7-3	4	B 3.4.16-1	3	B 3.5.8-2	8	B 3.6.8-6	13
B 3.4.7-4	4	B 3.4.16-2	4	B 3.5.8-3	8	B 3.6.8-7	13
B 3.4.7-5	4	B 3.4.16-3	3	B 3.6.1-1	3	B 3.6.8-8	13
B 3.4.7-6	3	B 3.4.17-1	4	B 3.6.1-2	3	B 3.6.8-9	13
B 3.4.8-1	4	B 3.4.17-2	3	B 3.6.1-3	3	B 3.6.9-1	3

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
B 3.6.9-2	3	B 3.7.10-1	3	B 3.8.6-4	4	16.3-10	4
B 3.6.9-3	3	B 3.7.10-2	3	B 3.8.7-1	3	16.3-11	0
B 3.6.9-4	3	B 3.7.10-3	3	B 3.8.7-2	3	16.3-12	1
B 3.7.1-1	3	B 3.7.10-4	3	B 3.8.7-3	3	16.3-13	4
B 3.7.1-2	3	B 3.7.10-5	3	B 3.8.7-4	3	16.3-14	0
B 3.7.1-3	3	B 3.8.1-1	3	B 3.8.7-5	3	16.3-15	0
B 3.7.1-4	3	B 3.8.1-2	3	B 3.8.7-6	3	16.3-16	4
B 3.7.1-5	3	B 3.8.1-3	3	B 3.8.7-7	3	16.3-17	0
B 3.7.1-6	3	B 3.8.1-4	3	B 3.8.7-8	3	16.3-18	0
B 3.7.2-1	3	B 3.8.1-5	3	B 3.9.1-1	3	16.3-19	4
B 3.7.2-2	3	B 3.8.1-6	3	B 3.9.1-2	3	16.3-20	0
B 3.7.2-3	3	B 3.8.1-7	3	B 3.9.1-3	3	16.3-21	0
B 3.7.2-4	3	B 3.8.1-8	3	B 3.9.2-1	3	16.3-22	4
B 3.7.2-5	3	B 3.8.1-9	3	B 3.9.2-2	3	16.3-23	4
B 3.7.2-6	3	B 3.8.1-10	3	B 3.9.2-3	3	16.3-24	0
B 3.7.2-7	3	B 3.8.1-11	3	B 3.9.3-1	3	16.3-25	4
B 3.7.3-1	13	B 3.8.1-12	3	B 3.9.3-2	3	16.3-26	0
B 3.7.3-2	13	B 3.8.2-1	3	B 3.9.3-3	3	16.3-27	0
B 3.7.3-3	13	B 3.8.2-2	3	B 3.9.4-1	13	16.3-28	4
B 3.7.3-4	13	B 3.8.2-3	3	B 3.9.4-2	13	16.3-29	0
B 3.7.4-1	4	B 3.8.2-4	4	B 3.9.5-1	4	16.3-30	0
B 3.7.4-2	4	B 3.8.3-1	3	B 3.9.5-2	3	16.3-31	4
B 3.7.5-1	3	B 3.8.3-2	3	B 3.9.5-3	3	16.3-32	0
B 3.7.5-2	3	B 3.8.3-3	3	B 3.9.5-4	3	16.3-33	4
B 3.7.5-3	3	B 3.8.3-4	3	B 3.9.5-5	3	16.3-34	1
B 3.7.6-1	10	B 3.8.4-1	3	B 3.9.6-1	3	16.3-35	4
B 3.7.6-2	10	B 3.8.4-2	3	B 3.9.6-2	3	16.3-36	0
B 3.7.6-3	10	B 3.8.4-3	3	B 3.9.6-3	5	16.3-37	0
B 3.7.6-4	10	B 3.8.4-4	3	B 3.9.6-4	5	16.3-38	4
B 3.7.6-5	10	B 3.8.5-1	3	B 3.9.7-1	7	16.3-39	0
B 3.7.6-6	10	B 3.8.5-2	3	B 3.9.7-2	7	16.3-40	0
B 3.7.6-7	10	B 3.8.5-3	3			16.3-41	4
B 3.7.7-1	3	B 3.8.5-4	3	16.2-1	0	16.3-42	0
B 3.7.7-2	3	B 3.8.5-5	3			16.3-43	0
B 3.7.7-3	3	B 3.8.5-6	3	16.3-1	0	16.3-44	0
B 3.7.7-4	3	B 3.8.5-7	3	16.3-2	0	16.3-45	0
B 3.7.8-1	13	B 3.8.5-8	3	16.3-3	0	16.3-46	4
B 3.7.8-2	13	B 3.8.5-9	3	16.3-4	4	16.3-47	1
B 3.7.8-3	13	B 3.8.5-10	3	16.3-5	0	16.3-48	0
B 3.7.9-1	3	B 3.8.5-11	3	16.3-6	0	16.3-49	0
B 3.7.9-2	3	B 3.8.6-1	4	16.3-7	4		
B 3.7.9-3	3	B 3.8.6-2	4	16.3-8	0		
B 3.7.9-4	3	B 3.8.6-3	4	16.3-9	0		

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision
i	7
ii	7
iii	7
17-1	10
17-2	10
17-3	10
17-4	10
17-5	10
17-6	10
17-7	10
17-8	10
17-9	10
17-10	10
17-11	10
17-12	10
17-13	10
17-14	10
17-15	10
17-16	10
17-17	10
17-18	10
17-19	10
17-20	10
17-21	10
17-22	10
17-23	10
17-24	10
i	11
ii	11
iii	11
iv	11
v	11
18.1-1	8
18.1-2	8
18.1-3	8
18.1-4	8
18.1-5	8
18.2-1	11
18.2-2	11
18.2-3	11
18.2-4	11
18.2-5	11
18.2-6	11
18.2-7	11
18.2-8	11
18.2-9	11
18.2-10	11
18.2-11	11
18.2-12	11
18.2-13	11
18.2-14	11
18.2-15	11
18.2-16	11
18.2-17	11
18.2-18	11
18.2-19	11
18.2-20	11
18.2-21	11
18.3-1	0
18.4-1	0
18.4-2	4
18.5-1	0
18.5-2	0
18.5-3	1
18.5-4	1
18.5-5	4
18.5-6	1
18.5-7	0
18.5-9	1
18.6-1	0
18.7-1	0
18.8-1	8
18.8-2	8
18.8-3	8
18.8-4	8
18.8-5	8
18.8-6	8
18.8-7	8
18.8-8	8
18.8-9	8
18.8-10	8
18.8-11	8
18.8-12	8
18.8-13	8
18.8-14	8
18.8-15	8
18.8-16	8
18.8-17	8
18.8-18	8
18.8-19	8
18.8-20	8
18.8-21	8
18.8-22	8
18.8-23	8
18.8-24	8
18.8-25	8
18.8-26	8
18.8-27	8
18.8-28	8
18.8-29	8
18.8-30	8
18.9-1	0
18.10-1	0
18.11-1	8
18.11-2	8
18.12-1	11
18.12-2	11
18.12-3	11
18.12-4	11
18.12-5	11
18.12-6	11
18.12-7	11
18.12-8	11
18.12-9	11
18.12-10	11
18.13-1	3
18.14-1	3
i	11
ii	11
iii	11
iv	11
v	11
vi	11
vii	11
viii	11
ix	11
x	11
xi	11
xii	11
19.1-1	0
19.1-2	0
19.1-3	1
19.1-4	1
19.1-5	0
19.1-6	0
19.2-1	0
19.3-1	0
19.4-1	0
19.5-1	0
19.6-1	0
19.7-1	0
19.8-1	0

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision
19.9-1	0
19.10-1	0
19.11-1	0
19.12-1	0
19.13-1	0
19.14-1	0
19.15-1	0
19.15-2	1
19.16-1	0
19.17-1	0
19.18-1	0
19.19-1	0
19.20-1	0
19.21-1	0
19.22-1	0
19.23-1	0
19.24-1	0
19.25-1	0
19.26-1	0
19.27-1	0
19.28-1	0
19.29-1	0
19.30-1	0
19.31-1	0
19.32-1	0
19.33-1	0
19.34-1	11
19.34-2	11
19.34-3	11
19.34-4	11
19.34-5	11
19.34-6	11
19.34-7	11
19.34-8	11
19.34-9	11
19.35-1	0
19.36-1	1
19.36-2	1
19.37-1	0
19.38-1	0
19.39-1	11
19.39-2	11
19.39-3	11
19.39-4	11
19.39-5	11
19.39-6	11
19.39-7	11
19.39-8	11
19.39-9	11
19.39-10	11
19.39-11	11
19.40-1	1
19.41-1	11
19.41-2	11
19.41-3	11
19.41-4	11
19.41-5	11
19.41-6	11
19.41-7	11
19.41-8	11
19.41-9	11
19.41-10	11
19.41-11	11
19.42-1	0
19.43-1	0
19.44-1	0
19.45-1	0
19.46-1	0
19.47-1	0
19.48-1	0
19.49-1	0
19.50-1	0
19.51-1	0
19.52-1	1
19.53-1	0
19.54-1	0
19.55-1	9
19.55-2	9
19.55-3	9
19.55-4	9
19.55-5	9
19.55-6	9
19.55-7	9
19.55-8	9
19.55-9	9
19.56-1	0
19.57-1	0
19.58-1	0
19.59-1	13
19.59-2	13
19.59-3	13
19.59-4	13
19.59-5	13
19.59-6	13
19.59-7	13
19.59-8	13
19.59-9	13
19.59-10	13
19.59-11	13
19.59-12	13
19.59-13	13
19.59-14	13
19.59-15	13
19.59-16	13
19.59-17	13
19.59-18	13
19.59-19	13
19.59-20	13
19.59-21	13
19.59-22	13
19.59-23	13
19.59-24	13
19.59-25	13
19.59-26	13
19.59-27	13
19.59-28	13
19.59-29	13
19.59-30	13
19.59-31	13
19.59-32	13
19.59-33	13
19.59-34	13
19.59-35	13
19.59-36	13
19.59-37	13

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

Page	Revision	Page	Revision	Page	Revision	Page	Revision
19.59-38	13	19.59-81	13	19D-8	14	19E-20	14
19.59-39	13	19.59-82	13	19D-9	14	19E-21	14
19.59-40	13	19.59-83	13	19D-10	14	19E-22	14
19.59-41	13	19.59-84	13	19D-11	14	19E-23	14
19.59-42	13	19.59-85	13	19D-12	14	19E-24	14
19.59-43	13	19.59-86	13	19D-13	14	19E-25	14
19.59-44	13	19.59-87	13	19D-14	14	19E-26	14
19.59-45	13	19.59-88	13	19D-15	14	19E-27	14
19.59-46	13	19.59-89	13	19D-16	14	19E-28	14
19.59-47	13	19.59-90	13	19D-17	14	19E-29	14
19.59-48	13	19.59-91	13	19D-18	14	19E-30	14
19.59-49	13	19.59-92	13	19D-19	14	19E-31	14
19.59-50	13	19.59-93	13	19D-20	14	19E-32	14
19.59-51	13	19.59-94	13	19D-21	14	19E-33	14
19.59-52	13	19.59-95	13	19D-22	14	19E-34	14
19.59-53	13	19.59-96	13	19D-23	14	19E-35	14
19.59-54	13	19.59-97	13	19D-24	14	19E-36	14
19.59-55	13	19.59-98	13	19D-25	14	19E-37	14
19.59-56	13	19.59-99	13	19D-26	14	19E-38	14
19.59-57	13	19.59-100	13	19D-27	14	19E-39	14
19.59-58	13			19D-28	14	19E-40	14
19.59-59	13	19A-1	1	19D-29	14	19E-41	14
19.59-60	13			19D-30	14	19E-42	14
19.59-61	13	19B-1	1			19E-43	14
19.59-62	13	19B-2	1	19E-1	14	19E-44	14
19.59-63	13	19B-3	1	19E-2	14	19E-45	14
19.59-64	13	19B-4	1	19E-3	14	19E-46	14
19.59-65	13	19B-5	1	19E-4	14	19E-47	14
19.59-66	13	19B-6	1	19E-5	14	19E-48	14
19.59-67	13	19B-7	3	19E-6	14	19E-49	14
19.59-68	13	19B-8	1	19E-7	14	19E-50	14
19.59-69	13	19B-9	1	19E-8	14	19E-51	14
19.59-70	13	19B-10	1	19E-9	14	19E-52	14
19.59-71	13			19E-10	14	19E-53	14
19.59-72	13	19C-1	1	19E-11	14	19E-54	14
19.59-73	13			19E-12	14	19E-55	14
19.59-74	13	19D-1	14	19E-13	14	19E-56	14
19.59-75	13	19D-2	14	19E-14	14	19E-57	14
19.59-76	13	19D-3	14	19E-15	14	19E-58	14
19.59-77	13	19D-4	14	19E-16	14	19E-59	14
19.59-78	13	19D-5	14	19E-17	14	19E-60	14
19.59-79	13	19D-6	14	19E-18	14	19E-61	14
19.59-80	13	19D-7	14	19E-19	14	19E-62	14

AP1000
TIER 2 LIST OF EFFECTIVE PAGES (Cont.)

LIST OF TIER 2 REVISION 1 PAGES

Section	Page No.	Type of Change
Master T of C	All	Editorial
VOLUME 2		
1.2	1.2-31	Editorial
1.5	1.5-1	Technical
1.5	1.5-6	Technical
1.5	1.5-9 and 1.5-10	Technical
1.6	1.6-2	Editorial
1.6	1.6-4	Editorial
1.6	1.6-6	Editorial
1.6	1.6-9	Editorial
1.6	1.6-11 through 1.6-15	Editorial
1.6	1.6-17 through 1.6-21	Editorial
1.9	1.9-69	Editorial
1.9	1.9-78	Editorial
1.9	1.9-100	Editorial
1.9	1.9-145	Editorial
1.9	1.9-154	Editorial
Appendix 1A	1A-55	Editorial
Appendix 1A	1A-68	Editorial
Appendix 1A	1A-70	Technical
VOLUME 3		
2	2-7	Technical
2	2-14	Technical
3. T of C	iv and v	Editorial
3. T of C	xv and xvi	Editorial
3. T of C	xix and xx	Editorial
3. T of C	xxii and xxiii	Editorial
3.2	3.2-17	Technical
3.4	3.4-6	Technical
3.4	3.4-9	Technical
3.6	3.6-34	Editorial
3.6	3.6-38	Technical
3.6	3.6-41	Editorial
3.6	3.6-42	Editorial
3.6	3.6-43	Technical
3.6	3.6-45 and 3.6-46	Technical
3.7	3.7-2	Technical
3.7	3.7-4 and 3.7-5	Technical
3.7	3.7-7 through 3.7-14	Technical
3.7	3.7-16	Technical

LIST OF TIER 2 REVISION 1 PAGES (Cont.)

Section	Page No.	Type of Change
3.7	3.7-19	Technical
3.7	3.7-45 through 3.7-52	Technical
3.7	3.7-62 through 3.7-64	Technical
3.7	3.7-69	Technical
3.7	3.7-71 and 3.7-72	Editorial
3.7	3.7-74 through 3.7-76	Technical
3.7	3.7-79	Technical
3.7	3.7-82 and 3.7-83	Technical
3.7	3.7-88 through 3.7-99	Editorial
3.7	3.7-101 and 3.7-102	Technical
3.7	3.7-104 through 3.7-107	Technical
3.7	3.7-114	Technical
3.7	3.7-171 through 3.7-173	Technical
3.7	3.7-205 and 3.7-206	Technical
VOLUME 4		
3.8	3.8-1	Technical
3.8	3.8-7	Technical
3.8	3.8-15	Technical
3.8	3.8-21	Editorial
3.8	3.8-35 and 3.8-36	Technical
3.8	3.8-47 through 3.8-49	Technical
3.8	3.8-53 and 3.8-54	Editorial
3.8	3.8-55 through 3.8-58	Technical
3.8	3.8-60	Technical
3.8	3.8-63	Technical
3.8	3.8-66	Editorial
3.8	3.8-68	Technical
3.8	3.8-72 through 3.8-82	Technical
3.8	3.8-84	Technical
3.8	3.8-91 through 3.8-96	Technical
3.8	3.8-99	Technical
3.9	3.9-18 and 3.9-19	Technical
3.9	3.9-21 and 3.9-22	Technical
3.9	3.9-22a	Editorial
3.9	3.9-96	Technical
3.9	3.9-167 and 3.9-168	Technical
3.11	3.11-12	Technical
3.11	3.11-14	Technical
3.11	3.11-16 and 3.11-17	Technical
3.11	3.11-19	Technical

LIST OF TIER 2 REVISION 1 PAGES (Cont.)

Section	Page No.	Type of Change
3.11	3.11-21 and 3.11-22	Technical
3.11	3.11-25 and 3.1-26	Technical
3.11	3.11-28	Technical
3.11	3.11-32	Technical
3.11	3.11-34	Technical
3.11	3.11-38	Technical
VOLUME 5		
Appendix 3B	3B-19 through 3B-21	Technical
Appendix 3B	3B-28 through 3B-31	Technical
Appendix 3B	3B-32	Technical
Appendix 3B	3B-35	Technical
Appendix 3B	3B-36	Editorial
Appendix 3D	3D-46	Technical
Appendix 3D	3D-59 through 3D-62	Technical
Appendix 3E	3E-13	Technical
Appendix 3H	3H-2 and 3H-3	Technical
Appendix 3H	3H-7 and 3H-8	Technical
Appendix 3H	3H-13	Technical
Appendix 3H	3H-17	Technical
Appendix 3H	3H-21 through 3H-32	Technical
Appendix 3H	3H-36 through 3H-39	Technical
Appendix 3H	3H-45 through 3H-51	Technical
Appendix 3H	3H-53	Editorial
Appendix 3H	3H-56	Editorial
Appendix 3H	3H-67	Editorial
4.1	4.1-5	Editorial
4.1	4.1-7	Technical
4.2	4.2-8	Technical
4.2	4.2-10 and 4.2-11	Technical
4.2	4.2-18	Technical
4.2	4.2-20 and 4.2-21	Technical
4.2	4.2-32	Editorial
4.2	4.2-37	Technical
4.3	4.3-26 through 4.3-28	Technical
4.3	4.3-30	Editorial
4.3	4.3-42	Editorial
4.3	4.3-47 and 4.3-48	Technical
4.3	4.3-52	Editorial
4.3	4.3-84	Technical
4.4	4.4-10	Editorial

LIST OF TIER 2 REVISION 1 PAGES (Cont.)

Section	Page No.	Type of Change
4.4	4.4-38 through 4.4-40	Technical
5. T of C	vi	Editorial
5.1	5.1-9 and 5.1-10	Technical
5.2	5.2-7	Technical
5.3	5.3-13	Technical
5.3	5.3-23	Technical
5.3	5.3-25	Technical
5.3	5.3-27	Technical
5.3	5.3-31 and 5.3-32	Technical
5.4	5.4-2	Technical
5.4	5.4-6	Technical
5.4	5.4-32	Technical
5.4	5.4-42	Technical
5.4	5.4-77	Technical
5.4	5.4-82	Technical
5.4	5.4-86	Technical
5.4	5.4-88	Technical
5.4	5.4-90	Technical
5.4	5.4-93	Technical
5.4	5.4-95	Technical
VOLUME 6		
6. T of C	vii	Editorial
6.2	6.2-3	Technical
6.2	6.2-14	Technical
6.2	6.2-50	Editorial
6.2	6.2-51 through 6.2-53	Technical
6.2	6.2-69 through 6.2-83	Technical
6.2	6.2-85 through 6.2-89	Technical
6.2	6.2-95 and 6.2-96	Technical
6.2	6.2-115 and 6.2-116	Technical
6.2	6.2-118 through 6.2-129	Technical
6.3	6.3-53	Technical
6.3	6.3-66	Editorial
6.4	6.4-19	Editorial
Appendix 6A	6A-9	Editorial
7. T of C	i	Editorial
7.1	7.1-1 through 7.1-5	Technical
7.1	7.1-9 and 7.1-10	Technical
7.1	7.1-13 through 7.1-21	Technical
7.1	7.1-23	Technical

LIST OF TIER 2 REVISION 1 PAGES (Cont.)

Section	Page No.	Type of Change
7.1	7.1-25	Technical
7.1	7.1-33	Technical
7.2	7.2-16	Technical
7.2	7.2-18 and 7.2-19	Technical
7.2	7.2-35	Technical
7.2	7.2-39	Technical
7.2	7.2-43	Technical
7.2	7.2-45	Technical
7.2	7.2-47	Technical
7.2	7.2-49	Technical
7.2	7.2-51	Technical
7.2	7.2-53	Technical
7.2	7.2-55	Technical
7.2	7.2-61	Technical
7.3	7.3-10	Technical
7.3	7.3-28	Technical
7.3	7.3-40	Technical
7.4	7.4-12	Technical
7.5	7.5-6	Technical
7.5	7.5-13 through 7.5-24	Technical
7.5	7.5-30 through 7.5-37	Technical
7.7	7.7-3	Technical
7.7	7.7-5 and 7.7-6	Technical
7.7	7.7-8	Editorial
7.7	7.7-18	Editorial
7.7	7.7-21 and 7.7-22	Technical
VOLUME 7		
8.3	8.3-55	Technical
9.1	9.1-6	Technical
9.1	9.1-11	Editorial
9.1	9.1-18 and 9.1-18a	Technical
9.1	9.1-18b	Editorial
9.1	9.1-20	Technical
9.1	9.1-23	Technical
9.1	9.1-42	Technical
9.1	9.1-49	Technical
9.1	9.1-59	Technical
9.2	9.2-47	Technical
9.2	9.2-48	Technical
9.2	9.2-69	Editorial

LIST OF TIER 2 REVISION 1 PAGES (Cont.)

Section	Page No.	Type of Change
9.2	9.2-71	Technical
9.2	9.2-73	Technical
9.3	9.3-61	Editorial
9.3	9.3-63	Editorial
9.3	9.3-65	Editorial
9.4	9.4-113	Editorial
9.4	9.4-125	Editorial
9.4	9.4-127	Editorial
VOLUME 8		
9.5	9.5-69	Technical
9.5	9.5-73	Editorial
9.5	9.5-75	Editorial
9.5	9.5-77	Editorial
Appendix 9A	9A-21	Technical
Appendix 9A	9A-127	Editorial
Appendix 9A	9A-141 through 9A-143	Editorial
Appendix 9A	9A-151 through 9A-155	Technical
10.1	10.1-1	Technical
10.1	10.1-4 and 10.1-5	Technical
10.2	10.2-17	Editorial
10.3	10.3-16	Technical
10.4	10.4-57 and 10.4-58	Technical
VOLUME 9		
11.1	11.1-7	Technical
11.1	11.1-10 and 11.1-11	Technical
11.1	11.1-15	Editorial
11.3	11.3-21	Editorial
11.4	11.4-16 through 11.4-25	Technical
11.4	11.4-27 through 11.4-31	Technical
12.2	12.2-4 and 12.2-5	Technical
12.2	12.2-9 through 12.2-11	Technical
12.2	12.2-13	Technical
12.2	12.2-27	Technical
12.2	12.2-28	Editorial
12.2	12.2-29	Technical
12.2	12.2-30	Editorial
12.2	12.2-31	Technical
12.2	12.2-35	Technical
12.2	12.2-36 through 12.2-38	Technical
12.2	12.2-39	Editorial

LIST OF TIER 2 REVISION 1 PAGES (Cont.)

Section	Page No.	Type of Change
12.2	12.2-45	Technical
12.2	12.2-49	Technical
12.2	12.2-50	Editorial
12.2	12.2-51 and 12.2-52	Technical
12.4	12.4-14	Editorial
14.3	14.3-18 and 14.3-19	Technical
VOLUME 10		
15	All	Technical
VOLUME 11		
16.1	1.1-3	Technical
16.1	3.3-14	Technical
16.1	3.3-18	Technical
16.1	3.4-6	Technical
16.1	3.4-6a	Technical
16.1	3.4-6b	Editorial
16.1	3.4-14 and 3.4-14a	Technical
16.1	3.4-14b	Editorial
16.1	3.4-18	Technical
16.1	3.4-30	Editorial
16.1	3.5-16	Technical
16.1	3.6-14	Technical
16.1	5.0-22	Editorial
16.1B	B3.1-20	Technical
16.1B	B3.1-30	Technical
16.1B	B3.1-35	Technical
16.1B	B3.2-31	Editorial
16.1B	B3.4-17	Technical
16.1B	B3.4-20 and B3.4-20a	Technical
16.1B	B3.4-20b	Editorial
16.1B	B3.4-38 and B3.4-38a	Technical
16.1B	B3.4-38b	Editorial
16.1B	B3.4-45	Technical
16.1B	B3.4-48	Technical
16.1B	B3.4-60 and B3.4-61	Technical
16.1B	B3.4-68	Editorial
16.1B	B3.4-75 through B3.4-77	Editorial
16.1B	B3.5-23 and B3.5-24	Editorial
16.1B	B3.5-33	Technical
16.1B	B3.6-15	Technical
16.1B	B3.6-24	Technical

LIST OF TIER 2 REVISION 1 PAGES (Cont.)

Section	Page No.	Type of Change
16.1B	B3.6-28	Technical
16.1B	B3.6-31 through B3.6-34	Technical
16.1B	B3.6-39	Technical
16.1B	B3.6-44 and B3.6-45	Technical
16.1B	B3.6-50	Technical
16.1B	B3.7-7 through B3.7-14	Editorial
16.1B	B3.7-20	Technical
16.1B	B3.7-42 and B3.7-43	Technical
16.1B	B3.9-16	Technical
16.1B	B3.9-19	Technical
16.1B	B3.9-21	Technical
16.1B	B3.9-23	Technical
VOLUME 12		
16.3	16.3-4	Technical
16.3	16.3-12	Editorial
16.3	16.3-34	Editorial
16.3	16.3-47	Technical
17.4	17-15	Technical
17.4	17-21 and 17-22	Technical
18. T of C	ii through v	Editorial
18.1	18.1-4	Editorial
18.2	18.2-1 and 18.2-2	Technical
18.2	18.2-6 through 18.2-9	Technical
18.2	18.2-16	Technical
18.2	18.2-18	Editorial
18.2	18.2-19	Technical
18.2	18.2-21	Technical
18.5	18.5-3 and 18.5-4	Technical
18.5	18.5-6	Technical
18.5	18.5-9	Technical
18.8	18.8-2	Technical
18.8	18.8-3	Technical
18.8	18.8-4 and 18.8-4a	Technical
18.8	18.8-4b	Editorial
18.8	18.8-5	Technical
18.8	18.8-6	Technical
18.8	18.8-7	Technical
18.8	18.8-9 and 18.8-10	Technical
18.8	18.8-19 and 18.8-20	Editorial
18.8	18.8-25	Technical

LIST OF TIER 2 REVISION 1 PAGES (Cont.)

Section	Page No.	Type of Change
18.8	18.8-26	Editorial
18.8	18.8-27	Technical
18.8	18.8-28	Editorial
18.8	18.8-28a and 18.8-28b	Technical
18.8	18.8-30	Technical
18.8	18.8-31	Editorial
18.11	18.11-1 through 18.11-5	Technical
18.12	18.12-1 and 18.12-2	Technical
19. T of C	i through v	Editorial
19. T of C	vii	Editorial
19. T of C	ix and x	Editorial
19.1	19.1-3	Technical
19.1	19.1-4	Technical
19.15	19.15-2	Editorial
19.34	19.34-1 through 19.34-6	Technical
19.36	19.36-1 and 19.36-2	Technical
19.39	19.39-1 through 19.39-10	Technical
19.40	19.40-1	Technical
19.41	19.41-3	Editorial
19.41	19.41-5 through 19.41-5a	Technical
19.41	19.41-6	Editorial
19.41	19.41-7 and 19.41-7a	Technical
19.41	19.41-8	Editorial
19.41	19.41-9	Technical
19.41	19.41-10	Editorial
19.52	19.52-1	Editorial
19.55	19.55-3 through 19.55-11	Technical
19.55	19.55-12	Editorial
19.55	19.55-13 and 19.55-14	Technical
19.59	19.59-1 through 19.59-66	Technical
Appendix 19A	19A-1	Editorial
Appendix 19B	19B-1 through 19B-10	Technical
Appendix 19C	19C-1	Technical
Appendix 19D	19D-12	Technical
Appendix 19D	19D-17	Editorial
Appendix 19D	19D-18	Technical
Appendix 19D	19D-26a	Technical
Appendix 19D	19D-26b	Editorial
Appendix 19D	19D-27 through 19D-29	Editorial
Appendix 19E	19E-17	Technical
Appendix 19E	19E-20	Technical

LIST OF TIER 2 REVISION 1 PAGES (Cont.)

Section	Page No.	Type of Change
Appendix 19E	19E-22	Technical
Appendix 19E	19E-27	Editorial
Appendix 19E	19E-33 and 19E-34	Editorial
Appendix 19E	19E-35 and 19E-36	Technical
Appendix 19E	19E-37 and 19E-38	Editorial
Appendix 19E	19E-39	Technical
Appendix 19E	19E-40 through 19E-43	Editorial
Appendix 19E	19E-44 through 19E-48	Technical
Appendix 19E	19E-52 through 19E-55	Technical

LIST OF TIER 2 REVISION 2 PAGES

Section	Page No.	Type of Change
Tier 2 List of Effective Pages	1 through 35	Editorial
Master T of C	i through xxxii	Editorial
List of Tier 2 Rev. 1 Pages	xxxiii	Editorial
List of Tier 2 Rev. 1 Pages	xxxvii	Editorial
List of Tier 2 Rev. 2 Pages	xliii and xliv	Editorial
VOLUME 2		
1.2	1.2-1	Technical
VOLUME 3		
3. T of C	xxiii	Editorial
VOLUME 5		
Appendix 3B	3B-19 and 3B-20	Technical
Appendix 3B	3B-23	Technical
Appendix 3B	3B-35 and 3B-36	Technical
Appendix 3B	3B-39	Technical
Appendix 3B	3B-41 and 3B-42	Technical
5.1	5.1-10	Technical
VOLUME 6		
6.3	6.3-54	Technical
7. T of C	i	Editorial
7.1	7.1-9	Editorial
7.1	7.1-20 and 7.1-21	Editorial
7.2	7.2-16	Editorial
7.3	7.3-24	Editorial
VOLUME 8		
9.5	9.5-33	Additional Information
9.5	9.5-33a	Editorial
9.5	9.5-34	Additional Information
9.5	9.5-34a	Editorial
9.5	9.5-37 and 9.5-38	Additional Information
9.5	9.5-38a and 9.5-38b	Editorial
9.5	9.5-39 and 9.5-39a	Additional Information
9.5	9.5-40	Additional Information
9.5	9.5-40a	Editorial
9.5	9.5-43 and 9.5-43a	Additional Information
9.5	9.5-44a	Editorial
9.5	9.5-46 and 9.5-46a	Additional Information
9.5	9.5-46b	Editorial

LIST OF TIER 2 REVISION 2 PAGES (Cont.)

Section	Page No.	Type of Change
9.5	9.5-47 and 9.5-47a	Additional Information
9.5	9.5-48	Additional Information
9.5	9.5-48a	Editorial
9.5	9.5-51	Additional Information
9.5	9.5-54	Additional Information
9.5	9.5-54a and 9.5-54b	Editorial
Appendix 9A	9A-5	Additional Information
Appendix 9A	9A-5a	Editorial
Appendix 9A	9A-6a	Editorial
10.2	10.2-17	Editorial
VOLUME 10		
15. T of C	ix	Editorial
15. T of C	xx and xxi	Editorial
15.6	15.6-36 through 15.6-40b	Additional Information
15.6	15.6-42	Editorial
15.6	15.6-55	Additional Information
15.6	15.6-58	Technical
15.6	15.6-61a	Technical
15.6	15.6-62a	Editorial
15.6	15.6-154 through 15.6-204	Technical

TIER 2 REVISION 3 CHANGE ROADMAP

Section	Page No.	Type of Change(1)
VOLUME 2		
Tier 2 List of Effective Pages	1 through 36	Editorial
Master T of C	i through xxxii	Editorial
Tier 2 Revision 3 Change Roadmap	xlv through lxiii	Editorial
1.1	1.1-1	Technical
1.1	1.1-4	210.036
1.2	1.2-6	630.011
1.2	1.2-8	Technical Editorial
1.2	1.2-35 through 1.2-45	Technical
1.2	1.2-47	Technical Editorial
1.2	1.2-51 through 1.2-57	Technical
1.6	1.6-3	440.045
1.6	1.6-5	210.001 (210.002, 210.003, 210.004, 210.006, 210.007, 210.008, 210.010, 210.013, and 210.014)
1.6	1.6-7	440.013 440.102 (R1)
1.6	1.6-11	440.021
1.6	1.6-12	420.027
1.6	1.6-13	420.013 420.023 (420.001) 420.027 420.030 Editorial
1.6	1.6-18	620.014 620.037
1.6	1.6-19	620.013 Editorial
1.6	1.6-20	620.014
1.6	1.6-21	Editorial

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
1.8	1.8-12	210.001 (210.002, 210.003, 210.004, 210.006, 210.007, 210.008, 210.010, 210.013, and 210.014)
1.8	1.8-13	251.014 420.028 (420.001) 420.029 (420.001) 440.102 (R1)
1.9	1.9-47	440.045
1.9	1.9-60	210.070
1.9	1.9-77	440.045
1.9	1.9-96	100.002
1.9	1.9-100	440.045
Appendix 1A	1A-20	435.001
Appendix 1A	1A-26 and 1A-27	435.001
Appendix 1A	1A-39	435.001
Appendix 1A	1A-49 through 1A-51	410.007
Appendix 1A	1A-52 and 1A-53	220.013
Appendix 1A	1A-57	460.003
Appendix 1A	1A-68	435.001
Appendix 1A	1A-69	435.001 Editorial
Appendix 1A	1A-70	410.007
VOLUME 3		
2	2-8	240.003 241.001
2	2-12	220.016 (R1)
2	2-12a	241.002
2	2-12b	Editorial
2	2-13	241.001
2	2-14	240.002 (230.008) 241.001

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
3, T of C	iii	Editorial
3, T of C	vi	Editorial
3, T of C	ix	Editorial
3, T of C	xv	Editorial
3, T of C	xvii	Editorial
3, T of C	xix	Editorial
3, T of C	xx	Editorial
3, T of C	xxi	Editorial
3.2	3.2-6	435.001
3.2	3.2-16	435.001
3.2	3.2-17	410.007
3.2	3.2-73	410.007
3.2	3.2-79	410.007
3.2	3.2-86	410.007
3.4	3.4-4	410.001
3.4	3.4-7	720.062
3.6	3.6-13	210.047
3.6	3.6-13a and 3.6-13b	Editorial
3.6	3.6-22	210.034
3.6	3.6-25	210.035
3.6	3.6-27	210.035
3.6	3.6-34	210.036
3.6	3.6-35	210.034
3.7	3.7-3	230.001 230.002 (R1)
3.7	3.7-4	210.041 Editorial
3.7	3.7-5	210.041
3.7	3.7-7	Letter DCP/NRC1526 Editorial
3.7	3.7-7a	230.007 (R1)
3.7	3.7-8	230.006 (R1) (230.013)
3.7	3.7-8a	Editorial
3.7	3.7-9	Letter DCP/NRC1526 230.009 (R1)

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
3.7	3.7-11	230.015 (R1) 230.018 (R1) (230.019)
3.7	3.7-12	210.037 230.016 (R1)
3.7	3.7-12a and 3.7-12b	Editorial
3.7	3.7-13	230.006 (R1)
3.7	3.7-16	230.007 (R1) NRC/W Meeting 11/12/02
3.7	3.7.17	230.006 (R1) (230.013) 230.007 (R1)
3.7	3.7-17a and 3.7-17b	Editorial
3.7	3.7-18	210.047 Editorial
3.7	3.7-21	210.038
3.7	3.7-41	210.042 210.043 210.044
3.7	3.7-50	210.041 Editorial
3.7	3.7-53	Technical
3.7	3.7-56	Letter DCP/NRC1526
3.7	3.7-57	Letter DCP/NRC1526 230.018 (R1) (230.019)
3.7	3.7-57a	230.018 (R1) (230.019)
3.7	3.7-57b	Editorial
3.7	3.7-58 through 3.7-61a	Letter DCP/NRC1526
3.7	3.7-61b	Editorial
3.7	3.7-62	Letter DCP/NRC1526 Editorial
3.7	3.7-63	Letter DCP/NRC1526
3.7	3.7-64 and 65	Letter DCP/NRC1526 Editorial
3.7	3.7-66	Letter DCP/NRC1526
3.7	3.7-67	Letter DCP/NRC1526 Editorial
3.7	3.7-68 through 3.7-71	Letter DCP/NRC1526
3.7	3.7-73	Letter DCP/NRC1526

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
3.7	3.7-74	230.006 (R1) (230.013)
3.7	3.7-75 through 3.7-82 – 3.7-83	230.006 (R1) (230.013)
3.7	3.7-83a	Editorial
3.7	3.7-108 and 3.7-109	Letter DCP/NRC1526
3.7	3.7-110	Letter DCP/NRC 1526 (230.018, R1) (230.019)
3.7	3.7-111 and 3.7-112	Letter DCP/NRC1526
3.7	3.7-114	230.018 (R1) (230.019)
3.7	3.7-115 through 3.7-135 – 3.7-140	Letter DCP/NRC1526
3.7	3.7-140a	Editorial
3.7	3.7-141 through 3.7-146	Letter DCP/NRC1526
3.7	3.7-149 through 3.7-157	Technical
3.7	3.7-161 and 3.7-163	Technical
3.7	3.7-175 through 3.7-204	Letter DCP/NRC1526
3.7	3.7-205	Letter DCP/NRC 1526 (230.010)
VOLUME 4		
3.8	3.8-4	220.003 (R1) 435.001
3.8	3.8-6	Editorial
3.8	3.8-15	252.009
3.8	3.8-16	220.006 (R1)
3.8	3.8-17	220.006 (R1) 220.012
3.8	3.8-19	220.011 (R1)
3.8	3.8-19a and 3.8-19b	Editorial
3.8	3.8-21	220.007
3.8	3.8-29	220.010
3.8	3.8-31	220.006 (R1)
3.8	3.8-45	220.015
3.8	3.8-47	230.007 (R1)
3.8	3.8-48	230.002 (R1) 230.007 (R1)
3.8	3.8-49	220.013
3.8	3.8-60	220.019 (R1)
3.8	3.8-98	220.018

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
3.8	3.8-127 through 3.8-133	220.011 (R1)
3.8	3.8-137	220.012
3.8	3.8-139 through 3.8-139d	220.012
3.8	3.8-139e	Editorial
3.8	3.8-145	220.007
3.8	3.8-162	220.012
3.8	3.8-189 and 3.8-190	220.017
3.8	3.8-193	220.017
3.9	3.9-26	210.045
3.9	3.9-32	210.001 (210.002, 210.003, 210.004, 210.006, 210.007, 210.008, 210.010, 210.013, and 210.014)
3.9	3.9-34	210.005
3.9	3.9-35 and 3.9-36	210.009
3.9	3.9-42	210.047
3.9	3.9-42a and 3.9-42b	Editorial
3.9	3.9-50	210.048
3.9	3.9-50a and 3.9-50b	Editorial
3.9	3.9-54	210.051
3.9	3.9-55	210.052
3.9	3.9-56	210.053
3.9	3.9-65	210.068
3.9	3.9-65a and 3.9-65b	Editorial
3.9	3.9-67	210.060
3.9	3.9-72	210.061
3.9	3.9-74	210.064
3.9	3.9-78 through 3.9-78a	210.021 210.027
3.9	3.9-78b	Editorial
3.9	3.9-79	210.022
3.9	3.9-80	210.024
3.9	3.9-84	Editorial
3.9	3.9-92	210.001 (210.002, 210.003, 210.004, 210.006, 210.007, 210.008, 210.010, 210.013, and 210.014)

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
3.9	3.9-93	210.045
3.9	3.9-94	210.045 210.001 (210.002, 210.003, 210.004, 210.006, 210.007, 210.008, 210.010, 210.013, and 210.014)
3.9	3.9-106	210.029
3.9	3.9-119	210.023
3.9	3.9-120	210.045
3.9	3.9-177	210.023
3.10	3.10-5 and 3.10-6	435.001
3.11	3.11-19	Technical
3.11	3.11-22	420.029 (420.001)
VOLUME 5		
Appendix 3B	3B-4	Editorial
Appendix 3B	3B-16	210.036 Editorial
Appendix 3B	3B-38	Editorial
Appendix 3D	3D-17	Technical
Appendix 3D	3D-19	Technical
Appendix 3D	3D-21	Technical
Appendix 3D	3D-21a and 3D-21b	Editorial
Appendix 3D	3D-45	Technical
Appendix 3D	3D-54 through 3D-57	Technical
Appendix 3E	3E-1	210.057
4, T of C	i through vii	Editorial
4.1	4.1-4	Technical
4.1	4.1-7	440.034
4.1	4.1-9	440.034
4.1	4.1-11	440.021

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
4.3	4.3-6	440.013
4.3	4.3-11	440.016
4.3	4.3-16	440.019
4.3	4.3-39	440.013 440.102 (R1) Editorial
4.3	4.3-41	Editorial
4.3	4.3-47	Technical
4.3	4.3-63 through 4.3-68	Editorial
4.3	4.3-70	Editorial
4.3	4.3-81 and 4.3-82	Editorial
4.4	4.4-2	440.021
4.4	4.4-3	440.030
4.4	4.4-4	440.021
4.4	4.4-7 through 4.4-10	440.021
4.4	4.4-12 through 4.4-15	440.021
4.4	4.4-19	440.033
4.4	4.4-20 and 4.4-21	440.021
4.4	4.4-23 and 4.4-24	440.021
4.4	4.4-26	440.021
4.4	4.4-28	440.021
4.4	4.4-37	440.021
4.4	4.4-38 and 4.4-39	440.034
4.4	4.4-40	440.021
5, T of C	iii	Editorial
5.1	5.1-10	440.033
5.1	5.1-15	Technical
5.1	5.1-17	Technical
5.1	5.1-23	Technical
5.2	5.2-9	251.012
5.2	5.2-13	252.003
5.2	5.2-19	250.001 (250.002)
5.2	5.2-22	630.030 (630.001)
5.2	5.2-27	Editorial

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
5.3	5.3-13 through 5.3-13a	251.013 251.018
5.3	5.3-13b	Editorial
5.3	5.3-15	440.038
5.3	5.3-21	720.050 720.063
5.3	5.3-22	251.014 720.050
5.3	5.3-22a and 5.3-22b	Editorial
5.3	5.3-23	251.018 (251.017) Editorial
5.3	5.3-36	720.050
5.3	5.3-37	Technical
5.4	5.4-1	440.040 (251.021)
5.4	5.4-2	440.040 (251.021) 440.041
5.4	5.4-2a and 5.4-2b	Editorial
5.4	5.4-3	440.041
5.4	5.4-3a and 5.4-3b	Editorial
5.4	5.4-6 through 5.4-9	440.040 (251.021)
5.4	5.4-17	252.007
5.4	5.4-40	440.036 440.046
5.4	5.4-49	440.046
5.4	5.4-49a and 5.4-49b	Editorial
5.4	5.4-61	440.036
5.4	5.4-63	220.012
5.4	5.4-77	440.040 (251.021)
5.4	5.4-79	440.040 (251.021)
5.4	5.4-90	Technical
5.4	5.4-93	440.036
5.4	5.4-95	440.040 (251.021)
5.4	5.4-100	440.047

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
VOLUME 6		
6.0, T of C	v	Editorial
6.1	6.1-1	252.008
6.1	6.1-4 through 6.1-8	281.001
6.1	6.1-9	281.001 Editorial
6.1	6.1-9a	281.001
6.1	6.1-9b	Editorial
6.1	6.1-10	281.001
6.1	6.1-13 and 6.1-14	281.001 Editorial
6.2	6.2-2	220.003
6.2	6.2-3	480.003
6.2	6.2-5	Editorial
6.2	6.2-50	480.005
6.2	6.2-60	220.015
6.2	6.2-64 and 6.2-65	220.015 480.006
6.2	6.2-95	640.001
6.2	6.2-103	480.009
6.2	6.2-137 through 6.2-145	Technical
6.3	6.3-10	260.003 440.051
6.3	6.3-38	260.003 440.051
6.3	6.3-41	260.003 440.051
6.3	6.3-49	420.027
6.3	6.3-61 and 6.3-62	Editorial
6.4	6.4-8	470.006
6.4	6.4-8a and 6.4-8b	Editorial
6.4	6.4-10 and 6.4-11	410.007
6.4	6.4-12	410.007

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[(1)]
Appendix 6A	6A-9	Editorial
7, T of C	i	Editorial
7, T of C	v and vi	Editorial
7.1	7.1-1	420.019
7.1	7.1-5 through 7.1-7	420.019
7.1	7.1-7a	Editorial
7.1	7.1-8	420.019
7.1	7.1-8a	Editorial
7.1	7.1-9	420.019
7.1	7.1-9a and 7.1-9b	Editorial
7.1	7.1-13	420.019
7.1	7.1-14	420.030
7.1	7.1-19	435.001
7.1	7.1-20	420.013 420.023 (420.001) 420.029 (420.001) 420.030 (420.001)
7.1	7.1-21	Editorial
7.1	7.1-23	420.007 420.008 420.020 420.046 620.041
7.1	7.1-25	420.007 420.020 420.046
7.1	7.1-26 and 7.1-26a	420.019
7.1	7.1-26b	Editorial
7.1	7.1-28 and 7.1-29	420.019
7.1	7.1-31 through 7.1-32a	420.019
7.1	7.1-34	420.019
7.2	7.2-14	435.001
7.2	7.2-16	420.028 (420.001)

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
7.3	7.3-16	420.037
7.4	7.4-12	420.024
7.5	7.5-21	Technical
7.5	7.5-24	420.033
7.5	7.5-34	420.033
7.7	7.7-10	Editorial
7.7	7.7-18	420.038
VOLUME 7		
8, T of C	i	Editorial
8.1	8.1-4	435.001
8.2	8.2-2	Editorial
8.2	8.2-3	435.002
8.2	8.2-4	Editorial
8.3	8.3-16	Editorial
8.3	8.3-26	280.003
8.3	8.3-51	Editorial
9, T of C	ix through xi	Editorial
9.1	9.1-16	720.063
9.1	9.1-16a and 9.1-16b	Editorial
9.2	9.2-48	Technical
9.2	9.2-69	Editorial
9.4	9.4-2	410.007
9.4	9.4-7 through 9.4-9	410.007
9.4	9.4-44 through 9.4-46	410.007
9.4	9.4-71	410.007
9.4	9.4-72	280.003
9.4	9.4-73	280.003 410.007
9.4	9.4-129	Editorial

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
VOLUME 8		
9.5	9.5-6 through 9.5-8	280.003
9.5	9.5-29	280.003
9.5	9.5-29a and 9.5-29b	Editorial
9.5	9.5-30	280.003
9.5	9.5-34	280.004
9.5	9.5-40	280.004
9.5	9.5-40a through 9.5-40c	Editorial
9.5	9.5-59 and 9.5-60	280.003
Appendix 9A	9A-2 and 9A-3	280.003
Appendix 9A	9A-8	280.006
Appendix 9A	9A-22	Technical
Appendix 9A	9A-124	280.003
Appendix 9A	9A-169 through 9A-179	Technical
Appendix 9A	9A-183 and 9A-185	Technical
Appendix 9A	9A-191 and 9A-193	Technical
10.1	10.1-1	Editorial
10.2	10.2-11	251.024
10.4	10.4-3	410.004
VOLUME 9		
11, T of C	iv	Editorial
11.2	11.2-1	460.004
11.2	11.2-1a and 11.2-1b	Editorial
11.2	11.2-39	Technical
11.2	11.2-41	Technical
11.3	11.3-1	410.011
11.4	11.4-14	460.008
12.2	12.2-9	Technical

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
12.3	12.3-27 through 12.3-37	Technical
12.3	12.3-59 through 12.3-69	Technical
12.3	12.3-89 through 12.3-99	Technical
12.4	12.4-4	Technical
12.4	12.4-11	Technical
12.4	12.4-12	Technical
12.4	12.4-13	Technical
13	i	620.015
13	13-1	620.015
13	13-3	620.016
14, T of C	iv	Editorial
14.1	14.1-1	Editorial
14.2	14.2-51	261.004
14.2	14.2-102 and 14.2-103	261.005
14.2	14.2-107 and 14.2-108	261.006
14.2	14.2-113	261.006 261.010
14.2	14.2-115	261.006 261.007
14.3	14.3-13 through 14.3-16	Editorial
14.3	14.3-18 and 14.3-19	Technical
14.3	14.3-22 and 14.3-23	Editorial
14.3	14.3-30	Editorial
14.3	14.3-32	Editorial
14.3	14.3-49	480.009
VOLUME 10		
15, T of C	viii	Editorial
15, T of C	ix	Editorial
15, T of C	xviii	Editorial
15.0	15.0-6	440.021
15.0	15.0-9	435.001 Editorial

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
15.0	15.0-17 through 15.0-18a	440.055 (440.021)
15.0	15.0-18b	Editorial
15.0	15.0-19 through 15.0-20a	440.055 (440.021)
15.0	15.0-20b	Editorial
15.0	15.0-21	440.055 (440.021)
15.0	15.0-27 through 15.0-28a	440.059
15.0	15.0-28b	Editorial
15.0	15.0-29	440.059
15.0	15.0-29a and 15.0-29b	Editorial
15.0	15.0-30	440.059
15.1	15.1-3	440.021
15.1	15.1-5	440.063
15.1	15.1-7	440.021
15.1	15.1-9	440.065
15.1	15.1-14	440.021
15.1	15.1-22	440.021
15.1	15.1-26	440.063
15.1	15.1-28	470.001
15.2	15.2-4	440.021
15.2	15.2-5	440.072
15.2	15.2-5a and 15.2-5b	Editorial
15.2	15.2-13 and 15.2-14	440.117
15.2	15.2-27	440.079
15.3	15.3-2	440.021
15.3	15.3-14	470.002
15.4	15.4-3	440.021
15.4	15.4-7	440.021
15.4	15.4-14 through 15.4-16	440.021
15.4	15.4-18	Editorial
15.4	15.4-39	Editorial
15.4	15.4-44	Editorial
15.4	15.4-45	470.003

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
15.6	15.6-3	440.021
15.6	15.6-11	440.089
15.6	15.6-25 through 15.25e	440.097
15.6	15.6-25f	Editorial
15.6	15.6-26	440.097
15.6	15.6-35	Editorial
15.6	15.6-40a	440.096
15.6	15.6-41	440.097
15.6	15.6-46	440.089
15.6	15.6-49	440.093
15.6	15.6-54 through 15.6-58	440.097
15.6	15.6-59 through 15.6-61a	440.094
15.6	15.6-81a through 15.6-81l	440.097
15.6	15.6-168	440.096
15.6	15.6-177 and 15.6-178	440.096
15.6	15.6-181	440.096
15.6	15.6-184	440.096
15.6	15.6-191 and 15.6-192	440.096
15.6	15.6-195	440.096
15.6	15.6-198	440.096
Appendix 15A	15A-3	Editorial
Appendix 15A	15A-5	451.005
Appendix 15A	15A-15	451.006
VOLUME 11		
16, T of C	i through vii	Editorial
16.1	16.1-1	Editorial
16.1	i through B 3.9.6-4	Format to NUREG-1431, Rev. 2
VOLUME 12		
17	17-2	260.001
17	17-10	260.001
17	17-18	260.002
17	17-19	260.003
17	17-20	260.002 720.061

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
18, T of C	iii	Editorial
18, T of C	v	620.038 Editorial
18.1	18.1-2	620.017 620.019
18.1	18.1-3	620.018 (620.012)
18.1	18.1-3a and 18.1-3b	Editorial
18.1	18.1-4	620.019
18.1	18.1-5	620.020 (620.018)
18.2	18.2-2	620.021
18.2	18.2-17	620.018
18.2	18.2-18	620.018 620.021 620.024 Editorial
18.2	18.2-19	Editorial
18.2	18.2-20	Editorial
18.2	18.2-21	620.026
18.8	18.8-1	620.028
18.8	18.8-2	620.029
18.8	18.8-4 and 18.8-4a	620.030 620.031
18.8	18.8-4b	Editorial
18.8	18.8-26	Editorial
18.11	18.11-1	Editorial
18.11	18.11-5	620.038
18.12	18.12-2	620.039
18.13	18.13-1	620.018 Editorial
18.14	18.14-1	620.018 Editorial

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
19, To of C	ii	Editorial
19, T of C	v	Editorial
19, T of C	vi	Editorial
19, T of C	viii	Editorial
19, T of C	ix through xi	Editorial
19.34	19.34-1	720.042
19.34	19.34-1a and 19.34-1b	Editorial
19.34	19.34-3 and 19.34-4	720.042
19.34	19.34-5 and 19.34-6	720.042 Editorial
19.34	19.34-6a	720.042
19.39	19.39-2 and 19.39-3	720.088 (720.048, 720.074, 720.083, 720.084, and 720.089)
19.39	19.39-3a and 19.39-3b	Editorial
19.39	19.39-6	Editorial
19.39	19.39-7	Editorial
19.39	19.39-9	Editorial
19.41	19.41-7a	720.054
19.59	19.59-21	Editorial
19.59	19.59-23 through 19.59-25	Technical
19.59	19.59-28 through 19.59-28i	720.038
19.59	19.59-28j	Editorial
19.59	19.59-62	Editorial
19.59	19.59-63	Technical
19.59	19.59-64a through 19.59-64x	720.038
19.59	19.59-66	Technical
Appendix 19B	19B-7	720.076
Appendix 19E	19E-6	440.110
Appendix 19E	19E-7	440.011
Appendix 19E	19E-10 and 19E-10a	720.066
Appendix 19E	19E-10b	Editorial
Appendix 19E	19E-11	Editorial

TIER 2 REVISION 3 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
Appendix 19E	19E-12	440.113
Appendix 19E	19E-34 through 19E-35e	440.119
Appendix 19E	19E-35f	Editorial
Appendix 19E	19E-36 and 19E-37	Editorial
Appendix 19E	19E-39 and 19E-40	Editorial
Appendix 19E	19E-42	440.115
Appendix 19E	19E-45 through 19E-47	440.119
Appendix 19E	19E-52 through 19E-86	440.119
Appendix 19E	19E-87 through 19E-90	Editorial

1. Changes incorporated as a result of Westinghouse responses to NRC Request for Additional Information (RAI) identified by RAI number. RAI number in parenthesis contains a reference to RAI response listed above.

TIER 2 REVISION 4 CHANGE ROADMAP

Section	Page No.	Type of Change[1]
VOLUME 2		
Tier 2 List of Effective Pages	1 through 36	Editorial
Master T of C	i through xxxii	Editorial
Tier 2 Revision 4 Change Roadmap	lxiv through lxxiv	Editorial
1.2	1.2-39	Technical
1.2	1.2-71 through 1.2-85	Technical
1.6	1.6-5	210.001 (R1)
1.6	1.6-12	251.021 (R1)
1.6	1.6-20	620.001 (R1)
1.8	1.8-12	251.004 (R1)
1.8	1.8-13	410.007 (R1)
1.8	1.8-16	620.018 (R1) Editorial
1.9	1.9-66 through 1.9-66d	Editorial
1.9	1.9-75	620.004 (R1)
1.9	1.9-84	Editorial
1.9	1.9-105	281.001 (R1)
1.9	1.9-107 and 1.9-108	410.007 (R2)
1.9	1.9-115	440.037 (R1)
1.9	1.9-152 and 1.9-153	Editorial
Appendix 1A	1A-16	Editorial
Appendix 1A	1A-28 and 1A-29	410.007 (R2)
Appendix 1A	1A-34	410.007 (R2)
VOLUME 3		
2	2-8	241.001 (R1)
2	2-15	451.008
3	iii	Editorial
3	xx	Editorial
3	xxii	Editorial

TIER 2 REVISION 4 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
3.4	3.4-16 and 3.4-17	620.004 (R1)
3.5	3.5-7	620.004 (R1)
3.6	3.6-8	620.004 (R1)
3.6	3.6-35	251.004 (R1)
3.7	3.7-6 through 3.7-6b	Technical
3.7	3.7-12	Editorial
3.7	3.7-20	Editorial
3.7	3.7-71	Technical
3.7	3.7-74	Editorial
3.7	3.7-85	620.004 (R1) Editorial
3.7	3.7-88 through 3.7-99	Editorial
3.7	3.7-171	Technical
VOLUME 4		
3.8	3.8-1	220.002 (R1)
3.8	3.8-12	Editorial
3.8	3.8-14	Editorial
3.8	3.8-15 and 3.8-15a	220.002 (R1)
3.8	3.8-15b	Editorial
3.8	3.8-17a	220.012 (R1)
3.8	3.8-17b	Editorial
3.8	3.8-19 and 3.8-20	Editorial
3.8	3.8-31	Editorial
3.8	3.8-40	620.004 (R 1)
3.8	3.8-55 and 3.8-56	241.001 (R1)
3.8	3.8-72	220.010 (R1)
3.8	3.8-99	241.001 (R1) Editorial
3.8	3.8-147	Technical
3.8	3.8-164 and 3.8-165	Technical
3.8	3.8-173	Editorial
3.8	3.8-178	Editorial
3.8	3.8-187 and 3.8-188	241.001 (R1)
3.8	3.8-189 and 3.8-190	Editorial
3.8	3.8-193	Editorial

TIER 2 REVISION 4 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
3.9	3.9-21	210.028 (R1)
3.9	3.9-49	210.049 (R1)
3.9	3.9-78a	210.021 (R1)
3.9	3.9-92	210.049 (R1) 251.011 (R1) Editorial
3.9	3.9-94	210.001 (R1)
3.9	3.9-119	210.023 (R1)
3.9	3.9-175 through 3.9-177	Editorial
3.11	3.11-31	Editorial
3.11	3.11-50	Editorial
VOLUME 5		
Appendix 3D	3D-20	Editorial
Appendix 3D	3D-36	Editorial
4.2	4.2-33	261.002 (R1)
4.5	4.5-3	251.011 (R1)
4.5	4.5-3a and 4.5-3b	Editorial
5.1	5.1-4	252.006 (R1) (251.022, R1)
5.2	5.2-9	251.012 (R1)
5.2	5.2-11	252.002 (R1)
5.2	5.2-27	410.005 (R1)
5.2	5.2-30	251.012 (R1)
5.2	5.2-31	252.002 (R1)
5.3	5.3-17a	252.001 (R1)
5.3	5.3-17b	Editorial
5.3	5.3-19	252.001 (R1)
5.3	5.3-19a and 5.3-19b	Editorial
5.3	5.3-22	720.050 (R1)
5.4	5.4-6	251.021 (R1)
5.4	5.4-12	252.006 (R1) (251.022, R1)

TIER 2 REVISION 4 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
5.4	5.4-15	252.006 (R1) (251.022, R1)
5.4	5.4-17	252.006 (R1) (251.022, R1)
5.4	5.4-19	252.006 (R1) (251.022, R1)
5.4	5.4-30 through 5.4-31	210.050 (R1)
5.4	5.4-42	620.004 (R1)
5.4	5.4-68 and 5.4-69	440.048 (R1) (440.049, R1)
5.4	5.4-70	620.004 (R1)
5.4	5.4-76	251.021 (R1)
5.4	5.4-94	440.048 (R1) (440.049, R1)
VOLUME 6		
6.1	6.1-9	281.001 (R1)
6.2	6.2-23	620.004 (R1)
6.2	6.2-50	480.011
6.2	6.2-97	620.004 (R1)
6.3	6.3-18	650.003 (R1)
6.3	6.3-65	440.050 (R1)
6.3	6.3-70 and 6.3-71	Editorial
6.4	6.4-8a	410.007 (R2)
6.4	6.4-11	410.007 (R1) 410.007 (R2)
6.4	6.4-12	410.007 (R2)
7	i	Editorial
7.1	7.1-1	420.029 (R1)
7.1	7.1-5	420.029 (R1)
7.1	7.1-8 through 7.1-9	420.007 (R1)
7.1	7.1-9a	Editorial
7.1	7.1-10	420.046 (R1)
7.1	7.1-10a and 7.1.10b	420.008 (R1) 420.046 (R1)
7.1	7.1-21	420.029 (R1) 420.046 (R1)

TIER 2 REVISION 4 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
7.2	7.2-16	420.045 (R1)
7.2	7.2-61	440.014 (R1)
7.4	7.4-12	420.047
7.4	7.4-13	620.004 (R1)
7.7	7.7-12	440.014 (R1)
7.7	7.7-12a and 7.7-12b	Editorial
7.7	7.7-15	440.014 (R1)
7.7	7.7-16	420.012 (R1)
VOLUME 7		
8.3	8.3-15	620.004 (R1)
8.3	8.3-20	620.004 (R1)
9	vii	Editorial
9.1	9.1-17	410.016 (R1)
9.1	9.1-19	410.018 (R1)
9.1	9.1-20 and 9.1-21	410.019 (R1) Editorial
9.1	9.1-52	Technical
9.4	9.4-5 and 9.4-6	620.004 (R1)
9.4	9.4-55 and 9.4-56	Technical
9.4	9.4-104	620.004 (R1)
VOLUME 8		
9.5	9.5-5	620.004 (R1)
9.5	9.5-18 through 9.5-22	620.004 (R1)
9.5	9.5-36	620.004 (R1)
9.5	9.5-38	620.004 (R1)
9.5	9.5-61 and 9.5-62	620.004 (R1)
9.5	9.5-64	Editorial
Appendix 9A	9A-5	620.004 (R1)
Appendix 9A	9A-36	620.004 (R1)
Appendix 9A	9A-51 and 9A-52	620.004 (R1)
Appendix 9A	9A-68	620.004 (R1)

TIER 2 REVISION 4 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
Appendix 9A	9A-70	620.004 (R1)
Appendix 9A	9A-84	Technical
Appendix 9A	9A-87 and 9A-88	Technical
Appendix 9A	9A-138	620.004 (R1)
Appendix 9A	9A-150	620.004 (R1)
Appendix 9A	9A-152 and 9A-153	Technical
Appendix 9A	9A-165	620.004 (R1)
Appendix 9A	9A-173	620.004
Appendix 9A	9A-193	620.004
Appendix 9A	9A-197 through 9A-205	Technical
VOLUME 9		
11.4	11.4-15	Editorial
11.5	11.5-13 and 11.5-14	471.011
12.1	12.1-6	471.011 (R1)
12.3	12.3-21	Editorial
12.3	12.3-31	Editorial
12.3	12.3-33 and 12.3-35	471.005 (R1)
12.3	12.3-49 through 12.3-53	Technical
12.3	12.3-63	Editorial
12.3	12.3-81	Technical
12.3	12.3-83	Editorial
12.3	12.3-93	Editorial
12.3	12.3-111 and 12.3-113	Technical
13	13-2	Editorial
14.2	14.2-74 and 14.2-75	Editorial
14.2	14.2-113	261.010 (R1)
14.2	14.2-132	620.004 (R1)
14.3	14.3-47	620.004 (R1)

TIER 2 REVISION 4 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
VOLUME 10		
15	ix	Editorial
15.3	15.3-14	Editorial
15.6	15.6-11	440.089 (R1)
15.6	15.6-25b	440.097 (R1)
15.6	15.6-25f	440.097 (R1)
15.6	15.6-27 through 15.6-30	Editorial
15.6	15.6-32 through 15.6-34	Editorial
15.6	15.6-36	Editorial
15.6	15.6-39	Technical
15.6	15.6-58	440.097 (R1)
15.6	15.6-58a	Editorial
15.6	15.6-58b and 15.6-58c	440.052 (R1)
15.7	15.7-5	630.052 (R1)
Appendix 15B	15B-6 and 15B-7	470.011 (R1)
VOLUME 11		
16	i	Editorial
16	iii	Editorial
16	vi	Editorial
16.1	i through vi	
16.1	3.3.1-2 through 3.3.1-7	630.021 (R1)
16.1	3.3.1-9	630.021 (R1)
16.1	3.3.2-1 through 3.3.2-3	630.021 (R1)
16.1	3.3.2-12	630.021 (R1)
16.1	3.3.2-14	Editorial
16.1	3.3.2-16	Editorial
16.1	3.3.2-18	Editorial
16.1	3.3.2-24	Editorial
16.1	3.3.4-1 and 3.3.4-2	Editorial
16.1	3.3.5-1	100.003 (R1) Editorial
16.1	3.4.4-1 and 3.4.4-2	Editorial
16.1	3.4.7-2	Editorial
16.1	3.4.8-2	Editorial

TIER 2 REVISION 4 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
16.1	3.4.11-1	630.028 (R1)
16.1	3.4.12-1	630.028 (R1)
16.1	3.5.1-2	Editorial
16.1	3.5.2-2	Editorial
16.1	3.5.4-3	Editorial
16.1	3.5.5-1	720.099
16.1	3.5.6-1	630.039 (R1)
16.1	3.5.6-2	Editorial
16.1	3.5.7-1	630.039 (R1)
16.1	3.5.8-1	630.039 (R1)
16.1	3.6.6-1 through 3.6.7-1	Editorial
16.1	3.7.3-1 and 3.7.3-2	Editorial
16.1	3.9.1-1	Editorial
16.1	3.9.5-2	Editorial
16.1	5.5-6	250.003 (R1)
16.1	5.5-9	250.003 (R1)
16.1	5.5-13	480.010
16.1	5.5-14	Editorial
16.1	5.6-3 and 5.6-4	Editorial
16.1	B 3.0-9 and B 3.0-10	Editorial
16.1	B 3.1.1-4	Editorial
16.1	B 3.1.4-2	Editorial
16.1	B 3.1.4-4 and B 3.1.4-5	Editorial
16.1	B 3.1.6-1	Editorial
16.1	B 3.1.7-4	Editorial
16.1	B 3.3.1-12	Editorial
16.1	B 3.3.1-23	Editorial
16.1	B 3.3.1-30 through B 3.3.1-32	630.021 (R1)
16.1	B 3.3.1-34 through B 3.3.1-37	630.021 (R1)
16.1	B 3.3.1-38	Editorial
16.1	B 3.3.1-39	630.021 (R1)
16.1	B 3.3.1-43 and B 3.3.1-44	630.021 (R1)
16.1	B 3.3.1-48	630.021 (R1)
16.1	B 3.3.2-3	Editorial
16.1	B 3.3.2-13	Editorial
16.1	B 3.3.2-26	Editorial
16.1	B 3.3.2-50	630.021 (R1)
16.1	B 3.3.2-53 and B 3.3.2-54	630.021 (R1)
16.1	B 3.3.2-63	Editorial

TIER 2 REVISION 4 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
16.1	B 3.3.2-64 and B 3.3.2-65	630.021 (R1)
16.1	B 3.3.2-68	630.021 (R1)
16.1	B 3.3.3-2	Editorial
16.1	B 3.3.5-1	100.003 (R1) Editorial
16.1	B 3.3.5-2	Editorial
16.1	B 3.3.5-3 and B 3.3.5-3a	100.003 (R1) Editorial
16.1	B 3.4.7-3 through B 3.4.7-5	Editorial
16.1	B 3.4.8-1	Editorial
16.1	B 3.4.9-2 and B 3.4.9-3	Editorial
16.1	B 3.4.10-1	Editorial
16.1	B 3.4.11-2	630.027 (R1)
16.1	B 3.4.11-3	630.028 (R1)
16.1	B 3.4.11-3a	Editorial
16.1	B 3.4.12-1	Editorial
16.1	B 3.4.12-2	630.028 (R1)
16.1	B 3.4.12-2a	Editorial
16.1	B 3.4.13-2	Editorial
16.1	B 3.4.13-3	Editorial
16.1	B 3.4.14-6	Editorial
16.1	B 3.4.15-3	Editorial
16.1	B 3.4.16-2	630.025 (R1)
16.1	B 3.4.17-1	Editorial
16.1	B 3.5.3-2	Editorial
16.1	B 3.5.4-2 through B 3.5.4-4	Editorial
16.1	B 3.5.4-6	Editorial
16.1	B 3.5.5-1 and B 3.5.5-2	720.099 Editorial
16.1	B 3.5.6-3	630.039 (R1) Editorial
16.1	B 3.5.7-2	630.039 (R1) Editorial
16.1	B 3.5.7-3	Editorial
16.1	B 3.5.8-2	630.039 (R1) Editorial
16.1	B 3.6.3-3	Editorial
16.1	B 3.6.4-1	480.010
16.1	B 3.6.7-3	Editorial
16.1	B 3.6.8-1	720.038 (R1) Editorial

TIER 2 REVISION 4 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
16.1	B 3.6.8-2	630.045 (R1) 720.038 (R1)
16.1	B 3.6.8-2a	720.038 (R1)
16.1	B 3.6.8-4 and B 3.6.8-5	Editorial
16.1	B 3.7.3-3 through B 3.7.4-2	Editorial
16.1	B 3.7.6-1	410.007 (R2) Editorial
16.1	B 3.7.6-2 through B 3.7.6-6	Editorial
16-1	B 3.7.6-7	410.007 (R2) Editorial
16.1	B 3.8.2-4	Editorial
16.1	B 3.8.6-1 through B 3.8.6-4	Editorial
16.1	B 3.9.5-1	Editorial
VOLUME 12		
16.3	16.3-4	Editorial
16.3	16.3-7	Editorial
16.3	16.3-10	Editorial
16.3	16.3-13	Editorial
16.3	16.3-16	Editorial
16.3	16.3-19	Editorial
16.3	16.3-22	Editorial
16.3	16.3-23	720.039 (R2) Editorial
16.3	16.3-25	720.039 (R2) Editorial
16.3	16.3-28	Editorial
16.3	16.3-31	Editorial
16.3	16.3-33	Editorial
16.3	16.3-35	Editorial
16.3	16.3-38	Editorial
16.3	16.3-41	Editorial
16.3	16.3-46	720.039 (R2) Editorial
17	17-1	Editorial to reflect current information
17	17-2	260.004
17	17-4 and 17-5	260.004

TIER 2 REVISION 4 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
17	17-8	260.004 260.005 Editorial
17	17-11	Editorial
18	ii	Editorial
18.1	18.1-3	620.018 (R1)
18.2	18.2-7	620.004 (R1)
18.2	18.2-17	620.004 (R1)
18.2	18.2-18	620.018 (R1)
18.4	18.4-2	620.018 (R1)
18.5	18.5-5	620.018 (R1)
18.8	18.8-5 and 18.8-6	620.001 (R1)
18.8	18.8-19	472.003 (R1)
18.8	18.8-26	620.018 (R1)
18.8	18.8-27	620.001 (R1)
19.59	19.59-23	720.038 (R1)
19.59	19.59-23a and 19.59-23b	Editorial
19.59	19.59-62	720.038 (R1)
19.59	19.59-64o	620.004 (R1)
Appendix 19E	19E-33	440.186
Appendix 19E	19E-33a and 19E-33b	Editorial

1. Changes incorporated as a result of Westinghouse responses to NRC Request for Additional Information (RAI) identified by RAI number. RAI number in parenthesis contains a reference to RAI response listed above.

TIER 2 REVISION 5 CHANGE ROADMAP

Section	Page No.	Type of Change[1]
VOLUME 2		
Tier 2 List of Effective Pages	1 through 36	Editorial
Master T of C	i through xxxii	Editorial
Tier 2 Revision 5 Change Roadmap	lxxv through lxxvii	Editorial
1.9	1.9-11	Technical
1.9	1.9-111	Editorial
Appendix 1A	1A-24	261.015
VOLUME 3		
2	i and ii	Editorial
2	2-6 and 2-7	240.005 Editorial
2	2-8	Editorial
2	2-9	240.005
2	2-10	230.023 240.005
2	2-12	240.005
2	2-13	240.005
3.2	3.2-27	Technical
VOLUME 4		
3.8	3.8-36	Incorporation of summary of results for design of critical sections
3.8	3.8-67	Technical – see letter DCP/NRC 1583
3.8	3.8-73 through 3.8-83	Incorporation of summary of results for design of critical sections
3.8	3.8-84	Editorial
3.8	3.8-151	Technical
3.8	3.8-179	Incorporation of summary of results for design of critical sections

TIER 2 REVISION 5 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
VOLUME 5		
5.2	5.2-19	Editorial
VOLUME 6		
6.1	6.1-4	Editorial
6.2	6.2-1	Editorial
6.2	6.2-52 and 6.2-53	Technical
6.2	6.2-69 through 6.2-83	Technical
6.2	6.2-95	Technical
6.2	6.2-118 through 6.2-123	Technical
6.2	6.2-125 through 6.2-128	Technical
VOLUME 7		
9.1	9.1-36 and 9.1-37	Technical
9.1	9.1-40	Technical
9.4	9.4-13	410.022
9.4	9.4-19 and 9.4-20	410.022
9.4	9.4-37	410.022
9.4	9.4-73	Editorial
VOLUME 8		
VOLUME 9		
13	13-3 through 13-10	Technical
14.2	14.2-6	261.016 (261.017)
14.2	14.2-9	261.016 (261.017)
14.2	14.2-81	420.048
VOLUME 10		
Appendix 15A	15A-14	Editorial

TIER 2 REVISION 5 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
VOLUME 11		
16.1	5.6-4	Editorial
16.1	B 3.2.3-5	Editorial
16-1	B 3.3.5-4	Editorial
16.1	B 3.9.6-3 and B 3.9.6-4	Editorial
VOLUME 12		
17	17-1	260.008 Editorial
17	17-11	260.008

1. Changes incorporated as a result of Westinghouse responses to NRC Request for Additional Information (RAI) identified by RAI number. RAI number in parenthesis contains a reference to RAI response listed above.

TIER 2 REVISION 6 CHANGE ROADMAP

Section	Page No.	Type of Change[1]
VOLUME 2		
Tier 2 List of Effective Pages	1 through 36	Editorial
Master T of C	i through xxxii	Editorial
Tier 2 Revision 6 Change Roadmap	lxxviii through lxxx	Editorial
VOLUME 3		
3	xv	Editorial
3	xvii	Editorial
3	xx	Editorial
3	xxiii	Editorial
3	xxiv	Editorial
3.7	3.7-7a through 3.7-8a	220.020
3.7	3.7-49	220.020
3.7	3.7-56	220.020
3.7	3.7-58	220.020
3.7	3.7-60 through 3.7-61c	220.020
3.7	3.7-61d	Editorial
3.7	3.7-62 through 3.7-70	220.020
3.7	3.7-115 through 3.7-130	220.020
3.7	3.7-141 through 3.7-146	220.020
3.7	3.7-175 through 3.7-204	220.020
3.7	3.7-205	230.018 (R3)
VOLUME 4		
3.8	3.8-21	220.007 (R1)
3.8	3.8-145	220.007 (R1)
VOLUME 5		
Appendix 3D	3D-58 through 3D-58d	Editorial
Appendix 3D	3D-59 and 3D-60	Technical
Appendix 3H	3H-6 and 3H-7	Completion of design of AP1000 critical sections
Appendix 3H	3H-10	Completion of design of AP1000 critical sections
Appendix 3H	3H-10a and 3H-10b	Editorial
Appendix 3H	3H-11 and 3H-12	Completion of design of AP1000 critical sections

TIER 2 REVISION 6 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
Appendix 3H	3H-17 through 3H-19	Completion of design of AP1000 critical sections
Appendix 3H	3H-20 through 3H-39	Completion of design of AP1000 critical sections Editorial
Appendix 3H	3H-45 through 3H-46a	Completion of design of AP1000 critical sections
Appendix 3H	3H-46b	Editorial
Appendix 3H	3H-47 and 3H-48	Completion of design of AP1000 critical sections
Appendix 3H	3H-51	Completion of design of AP1000 critical sections
Appendix 3H	3H-56	Completion of design of AP1000 critical sections
Appendix 3H	3H-67	Completion of design of AP1000 critical sections
5.3	5.3-22	Editorial
VOLUME 6		
6.2	6.2-95 and 6.2-96	Editorial
6.4	6.4-8a	410.007 (R3)
6.4	6.4-12	410.007 (R3)
VOLUME 7		
9.1	9.1-18	Editorial
VOLUME 8		
VOLUME 9		
13	13-3 through 13-8	Technical
14.2	14.2-129	261.018
14.3	14.3-19	Editorial
VOLUME 10		

TIER 2 REVISION 6 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
VOLUME 11		
16.1	3.6.6-2	Editorial
16.1	B 3.5.1-1	Editorial
16.1	B 3.5.1-3	Editorial
16.1	B 3.5.2-2	Editorial
VOLUME 12		

1. Changes incorporated as a result of Westinghouse responses to NRC Request for Additional Information (RAI) identified by RAI number.

TIER 2 REVISION 7 CHANGE ROADMAP

Section	Page No.	Type of Change[(1)]
VOLUME 2		
Tier 2 List of Effective Pages	1 through 35	Editorial
Master T of C	i through xxxii	Editorial
Tier 2 Revision 7 Change Roadmap	lxxxi through lxxxix	Editorial
1, T of C	ii through iv	Editorial
1.6	1.6-4	DSER OI 14.2.7-3 Editorial
1.6	1.6-18	DSER OI 20.7-2 Editorial
1.6	1.6-19 and 1.6-20	DSER OI 18.11.3.5-1 (R1)
1.8	1.8-11 and 1.8-12	Letter DCP NRC 1613 Editorial
1.8	1.8-13	DSER OI 4.4-1 DSER OI 6.2.1.8.3-1 (R2) Letter DCP NRC 1613 Editorial
1.8	1.8-14	DSER OI 9.5.1-1 DSER OI 14.3.2-7 (R1) Editorial
1.8	1.8-15 and 1.8-16	Letter DCP NRC 1613 Editorial
1.8	1.8-17	Editorial
1.9	1.9-56	DSER OI 13.3-1 (R1)
1.9	1.9-102	DSER OI 14.2.7-3 Editorial
1.9	1.9-112	Editorial
Appendix 1A	1A-12	DSER OI 17.3.2-3 (R1)
Appendix 1A	1A-46	Editorial
VOLUME 3		
2, T of C	i and ii	Editorial
2	2-2	DSER OI 3.3.1-1
2	2-3	DSER OI 2.3.4-1 Editorial

TIER 2 REVISION 7 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
2	2-4	Editorial
2	2-7 and 2-8	DSER OI 3.7.2.16-1
2	2-9 through 2-12	Editorial
2	2-13 through 2-16	DSER OI 2.3.4-1
3, T of C	iii through vii	Editorial
3, T of C	xiv through xvi	Editorial
3, T of C	xviii through xxiii	Editorial
3.1	3.1-11	DSER OI 13.3-1 (R1) Editorial
3.2	3.2-34	Editorial
3.6	3.6-35	DSER OI 3.6.3.4-1 (R1)
3.7	3.7-5	Editorial
3.7	3.7-8 and 3.7-9	Confirmatory Item 3.7.2.1-2
3.7	3.7-19 and 3.7-20	Editorial
3.7	3.7-47	Letter DCP NRC 1613
3.7	3.7-51 through 3.7-58	Editorial
3.7	3.7-65	Editorial
3.7	3.7-66	Confirmatory Item 3.7.2.1-2 Editorial
3.7	3.7-69	Confirmatory Item 3.7.2.1-2 Editorial
3.7	3.7-93	Editorial
3.7	3.7-130	Editorial
VOLUME 4		
3.8	3.8-1	DSER OI 14.3.2-3
3.8	3.8-4	DSER OI 3.8.2.2-2
3.8	3.8-21	Editorial
3.8	3.8-32	Editorial
3.8	3.8-58	Editorial
3.8	3.8-60	DSER OI 3.8.5.5-1 Editorial
3.8	3.8-61	Letter DCP NRC 1613 Editorial
3.8	3.8-82	Editorial
3.8	3.8-89	Editorial
3.8	3.8-90	Technical

TIER 2 REVISION 7 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
3.8	3.8-140	Editorial
3.8	3.8-184	Technical
3.9	3.9-101	DSER OI 14.2-1
VOLUME 5		
Appendix 3H	3H-4	Editorial
Appendix 3H	3H-12	Editorial
Appendix 3H	3H-52	Editorial
4, T of C	ii	Editorial
4, T of C	vii	Editorial
4.3	4.3-28	Technical
4.4	4.4-1	Editorial
4.4	4.4-3	Editorial
4.4	4.4-16	Editorial
4.4	4.4-23	Editorial
4.4	4.4-31	DSER OI 4.4-1
4.4	4.4-39	Editorial
4.4	4.4-42	Editorial
5, T of C	iii	Editorial
5, T of C	vi and vii	Editorial
5.2	5.2-9	DSER OI 5.2.3-1
5.2	5.2-30	DSER OI 4.5.1-1 DSER OI 4.5.1-2
5.2	5.2-31	DSER OI 5.2.3-1
5.2	5.2-32 through 5.2-36	Editorial
5.3	5.3-21 and 5.3-22	Technical
5.3	5.3-23	DSER OI 14.3.2-11 (R1) Technical
5.3	5.3-26 and 5.3-27	Editorial
VOLUME 6		
6, T of C	i through iii	Editorial
6, T of C	vi and vii	Editorial

TIER 2 REVISION 7 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
6.1	6.1-4	DSER OI 6.1.1-1
6.1	6.1-8	Editorial
6.1	6.1-13	Confirmatory Item 3.7.2.1-2
6.1	6.1-14	Editorial
6.2	6.2-95	DSER OI 14.2-1
6.3	6.3-11	Editorial
6.3	6.3-15	Editorial
6.3	6.3-17	DSER OI 6.2.1.8.1-1
6.3	6.3-22	Editorial
6.3	6.3-27	Editorial
6.3	6.3-38	Editorial
6.3	6.3-43 and 6.3-44	Editorial
6.3	6.3-47 and 6.3-48	Editorial
6.3	6.3-49	DSER OI 6.2.1.8.3-1 (R2)
6.3	6.3-50 through 6.3-56	Editorial
6.4	6.4-1	DSER OI 13.3-1 (R1)
6.4	6.4-7	DSER OI 13.3-1 (R1)
6.4	6.4-8 and 6.4-9	DSER OI 2.3.4-1
6.4	6.4-10	DSER OI 13.3-1 (R1)
7.2	7.2-20	DSER OI 14.3.3-5 (R1)
7.2	7.2-24	DSER OI 14.3.3-5 (R1)
7.2	7.2-55	DSER OI 14.3.3-5 (R1)
7.3	7.3-11	DSER OI 14.3.3-5 (R1)
7.3	7.3-32	DSER OI 14.3.3-5 (R1)
7.3	7.3-37 and 7.3-38	DSER OI 14.3.3-5 (R1)
7.7	7.7-5 and 7.7-6	Technical
VOLUME 7		
8, T of C	ii and iii	Editorial
8.2	8.2-2	DSER OI 8.2.3.1-1 (R1)
8.3	8.3-18	DSER OI 20.7-2
8.3	8.3-27 through 8.3-38	Editorial

TIER 2 REVISION 7 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
9, T of C	i	Editorial
9, T of C	iv through vi	Editorial
9, T of C	ix through xi	Editorial
9.1	9.1-15 and 9.1-16	Technical
9.1	9.1-37	Editorial
9.1	9.1-41	Editorial
9.1	9.1-52	Editorial
9.1	9.1-59	Technical
9.4	9.4-3	DSER OI 14.3.3-17 (R1)
9.4	9.4-11	DSER OI 13.3-1 (R1) Editorial
9.4	9.4-12	DSER OI 13.3-1 (R1)
9.4	9.4-76 and 9.4-77	Editorial
VOLUME 8		
9.5	9.5-15	DSER OI 9.5.1-1 DSER OI 19.1.10.1-6
9.5	9.5-16	DSER OI 14.3.2-7 (R1)
9.5	9.5-19	DSER OI 9.5.2-3 DSER OI 14.3.2-7 (R1)
9.5	9.5-21	DSER OI 14.3.3-17 (R1)
9.5	9.5-31	DSER OI 9.5.2-3
9.5	9.5-32 through 9.5-64	Editorial
9.5	9.5-69	Editorial
9.5	9.5-72	Editorial
10, T of C	i	Editorial
10, T of C	v and vi	Editorial
10.2	10.2-13	DSER OI 10.2.8-3
10.2	10.2-17	Editorial
10.2	10.2-24	Editorial
VOLUME 9		
12.3	12.3-25 through 12.3-33	Technical
12.3	12.3-59	Technical
12.3	12.3-63 and 12.3-65	Technical

TIER 2 REVISION 7 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
12.3	12.3-69 and 12.3-71	Technical
12.3	12.3-93	Technical
13, T of C	i	Editorial
13	13-2	DSER OI 13.3-2
13	13-3	DSER OI 19.3.3-1
14, T of C	i through v	Editorial
14.2	14.2-18	DSER OI 14.2-1
14.2	14.2-20	DSER OI 14.2-1
14.2	14.2-21	DSER OI 14.2-1 Editorial
14.2	14.2-22 and 14.2-23	DSER OI 14.2-1
14.2	14.2-32	DSER OI 14.2-1
14.2	14.2-48	DSER OI 14.2-1
14.2	14.2-54 through 14.2-56	DSER OI 14.3.2-12 (R2)
14.2	14.2-57	DSER OI 14.2-1
14.2	14.2-60	DSER OI 14.2-1
14.2	14.2-81	DSER OI 14.3.2-7 (R1)
14.2	14.2-90 through 14.2-93	DSER OI 14.2-1
14.2	14.2-94	DSER OI 14.2-1 Editorial
14.2	14.2-103	DSER OI 14.2-1
14.2	14.2-106 and 14.2-107	DSER OI 14.2-1
14.2	14.2-112	DSER OI 14.2-1
14.2	14.2-127	DSER OI 14.2-1
14.3	14.3-19 and 14.3-20	DSER OI 14.2-1
14.3	14.3-23	DSER OI 14.2-1 Editorial
14.3	14.3-49	DSER OI 2.3.4-1
VOLUME 10		
15, T of C	v	Editorial
15, T of C	vii through xii	Editorial
15, T of C	xiv and xv	Editorial
15, T of C	xviii through xxi	Editorial
15.0	15.0-25	Editorial

TIER 2 REVISION 7 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
15.1	15.1-18 through 15.1-20	DSER OI 2.3.4-1
15.1	15.1-27	DSER OI 2.3.4-1
15.3	15.3-8 through 15.3-10	DSER OI 2.3.4-1
15.3	15.3-14 and 15.3-15	DSER OI 2.3.4-1
15.4	15.4-36 through 15.4-38	DSER OI 2.3.4-1
15.4	15.4-46	DSER OI 2.3.4-1
15.6	15.6-5	DSER OI 2.3.4-1
15.6	15.6-15	DSER OI 2.3.4-1
15.6	15.6-19	DSER OI 2.3.4-1
15.6	15.6-21 through 15.6-23	DSER OI 2.3.4-1
15.6	15.6-29	Editorial
15.6	15.6-33 through 15.6-43	Editorial
15.6	15.6-44 and 15.6-45	DSER OI 15.2.7-1 (R1) Editorial
15.6	15.6-46 through 15.6-49	DSER OI 15.2.7-1 (R1)
15.6	15.6-50	Editorial
15.6	15.6-52	Editorial
15.6	15.6-56	DSER OI 2.3.4-1
15.6	15.6-58 through 15.6-61	DSER OI 2.3.4-1
15.6	15.6-67 through 15.6-72	Editorial
15.6	15.6-140 through 15.6-182	Editorial
15.6	15.6-183 through 15.6-210	DSER OI 15.2.7-1 (R1)
15.7	15.7-5 and 15.7-6	DSER OI 2.3.4-1
Appendix 15A	15A-5 and 15A-6	DSER OI 2.3.4-1
Appendix 15A	15A-14 through 15A-18	DSER OI 2.3.4-1
Appendix 15B	15B-5 through 15B-8	DSER OI 2.3.4-1
VOLUME 11		
16, T of C	iii	Editorial
16, T of C	vii	Editorial
16.1	i through vi	Editorial
16.1	3.3.1-8	Editorial
16.1	3.4.10-2	DSER OI 16.2-1
16.1	3.5.6-1	DSER OI 16.2-2
16.1	3.5.6-2 through 3.5.6-4	Editorial

TIER 2 REVISION 7 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
16.1	3.9.7-1	DSER OI 16.2-3
16.1	3.9.7-2	Editorial
16.1	5.5-13	DSER OI 6.2.6.4-1
16.1	B 3.3.1-41 and B 3.3.1-42	Editorial
16.1	B 3.3.5-5	DSER OI 20.7-2
16.1	B 3.5.6-1	DSER OI 16.2-2
16.1	B 3.5.6-3	DSER OI 16.2-2
16.1	B 3.6.4-1	DSER OI 6.2.6.4-1
16.1	B 3.9.7-1 and B 3.9.7-2	DSER OI 16.2-3
VOLUME 12		
17, T of C	ii and iii	Editorial
17	17-3	Editorial
17	17-9	Editorial
17	17-10	DSER OI 17.5-1
17	17-12 through 17-14	Editorial
17	17-15 through 17-18	DSER OI 14.3.2-15 (R1) Editorial
17	17-19	DSER OI 14.3.2-15 (R1)
17	17-20	DSER OI 14.3.2-15 (R1) Editorial
17	17-21	DSER OI 14.3.2-15 (R1)
17	17-22	DSER OI 14.3.2-15 (R1) Editorial
18, T of C	ii through v	Editorial
18.1	18.1-4	DSER OI 18.11.3.5-1 (R1)
18.8	18.8-4	Editorial
18.8	18.8-8	Editorial
18.8	18.8-17	DSER OI 14.3.2-7 (R1)
18.8	18.8-18 and 18.8-19	DSER OI 13.3-2
18.8	18.8-25	DSER OI 18.11.3.5-1 (R1)
18.8	18.8-30	Editorial
18.11	18.11-1	DSER OI 18.11.3.5-1 (R1)

TIER 2 REVISION 7 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
19, T of C	v through xii	Editorial
19.59	19.59-25 and 19.59-26	DSER OI 19.1.10.3-1 (R1)
19.59	19.59-36	DSER OI 19A.3-2 (R1)
19.59	19.59-44 through 19.59-69	Editorial
19.59	19.59-72	DSER OI 19.1.10.3-1 (R1)
19.59	19.59-73	Editorial
19.59	19.59-99	DSER OI 19.1.10.3-1 (R1)

1. Changes incorporated as a result of Draft Safety Evaluation Report (DSER) Open Item (OI) Response identified by DSER OI number.

TIER 2 REVISION 8 CHANGE ROADMAP

Section	Page No.	Type of Change(1)
VOLUME 2		
Tier 2 List of Effective Pages	1 through 35	Editorial
Master T of C	i through xxxii	Editorial
Tier 2 Revision 8 Change Roadmap	xc through xcvii	Editorial
1, T of C	iii through v	Editorial
1.2	1.2-61 through 1.2-65	DSER OI 9.5.1-1 (R2)
1.6	1.6-1	Editorial
1.6	1.6-12	DSER OI 5.3.3-1 (R2)
1.6	1.6-17	Editorial
1.6	1.6-19	DSER OI 14.3.3-14 DSER OI 14.3.3-15 DSER OI 14.3.3-16 DSER OI 18.11.3.5-2 DSER OI 18.11.3.5-3 DSER OI 18.11.3.5-4
1.6	1.6-20	DSER OI 14.3.3-14 DSER OI 14.3.3-15 DSER OI 14.3.3-16 DSER OI 18.11.3.5-2 DSER OI 18.11.3.5-3 DSER OI 18.11.3.5-4 Editorial
Appendix 1B	1B-1 through 1B-24	DSER OI 19.4-1 (R1)
VOLUME 3		
2, T of C	i and ii	Editorial
2	2-6	DSER OI 2.5.1-1 (R1)
2	2-8	Editorial (per Oct. 6-9 meeting)
2	2-10	DSER OI 2.5.4-2 (R2)
2	2-11	DSER OI 3.8.5.1-1 (R1)
2	2-12	DSER OI 2.5.4-2 (R2) DSER OI 3.8.5.1-1 (R1)
2	2-13	DSER OI 3.8.5.1-1 (R1)
2	2-14	DSER OI 2.5.4-2 (R2)
2	2-16 and 2-17	DSER OI 2.3.4-1 (R2)

TIER 2 REVISION 8 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
3, T of C	iii through v	Editorial
3, T of C	xv through xvii	Editorial
3, T of C	xix through xxii	Editorial
3.3	3.3-1	DSER OI 3.3.1-1 (R1) DSER OI 3.3.1-2 (R1) Editorial (per Oct. 6-9 meeting)
3.3	3.3-2 and 3.3-3	DSER OI 3.3.2-1 (R1)
3.3	3.3-4	DSER OI 3.3.2-2 (R1) Editorial
3.3	3.3-5	DSER OI 3.3.1-2 (R1) Editorial
3.4	3.4-1 through 3.4-24	Editorial (format)
3.6	3.6-27	Editorial
3.6	3.6-28	DSER OI 14.2-1 Item aa (R3) Editorial
3.7	3.7-7	Editorial (per Oct. 6-9 meeting)
3.7	3.7-9	Editorial (per Oct. 6-9 meeting)
3.7	3.7-11	Editorial
3.7	3.7-18 and 3.7-19	Editorial
3.7	3.7-26 through 3.7-28	Editorial
3.7	3.7-48 and 3.7-49	Editorial
3.7	3.7-73	Editorial (per Oct. 6-9 meeting)
3.7	3.7-75	Editorial (per Oct. 6-9 meeting)
3.7	3.7-79	Editorial
3.7	3.7-89	Editorial
3.7	3.7-135 and 3.7-137	Editorial
3.7	3.7-149	Editorial
3.7	3.7-195 and 3.7-197	Editorial
VOLUME 4		
3.8	3.8-1	DSER OI 3.8.2.1-1 (R2)
3.8	3.8-2	DSER OI 3.8.2.1-1 (R2) DSER OI 19A.2-8 (R2)
3.8	3.8-29 and 3.8-30	DSER OI 3.8.3.5-2 (R1)
3.8	3.8-37	DSER OI 3.8.3.5-2 (R1)
3.8	3.8-50	DSER OI 3.8.4.2-1 (R2)

TIER 2 REVISION 8 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
3.8	3.8-72	Technical (per Oct. 6-9 meeting)
3.8	3.8-80 through 3.8-82	DSER OI 3.8.3.5-2 (R1)
3.8	3.8-94	Editorial
3.9	3.9-42	DSER OI 14.2-1 Item aa (R3)
3.9	3.9-91	Editorial
3.9	3.9-94	Editorial
3.9	3.9-101	Editorial
3.9	3.9-103	Editorial
3.9	3.9-105	Editorial
3.9	3.9-110	Editorial
3.9	3.9-112	Editorial
3.9	3.9-120	Editorial
VOLUME 5		
Appendix 3H	3H-22 and 3H-23	Technical (per Oct. 6-9 meeting)
Appendix 3H	3H-36	Technical (per Oct. 6-9 meeting)
Appendix 3H	3H-53	Technical (per Oct. 6-9 meeting)
5, T of C	ii through vii	Editorial
5.2	5.2-2	NRC CIP Team Comment
5.2	5.2-7	DSER OI 5.3.3-1 (R2)
5.2	5.2-8	Editorial
5.2	5.2-12	Editorial
5.2	5.2-21	Editorial
5.2	5.2-30	DSER OI 4.5.1-2 (R1) Editorial
5.2	5.2-36	Editorial
5.3	5.3-6	DSER OI 20.7-1 (R1)
5.3	5.3-14	DSER OI 5.3.3-1 (R2)
5.3	5.3-18	Editorial
5.3	5.3-22	DSER OI 19.2.3.3-1 (R2)
5.3	5.3-23	DSER OI 20.7-1 (R1)
5.3	5.3-24	DSER OI 5.3.3-1 (R2)
5.3	5.3-32 and 5.3-33	DSER OI 5.3.3-1 (R2) Editorial

TIER 2 REVISION 8 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
5.4	5.4-56	Editorial
5.4	5.4-59	Editorial
5.4	5.4-61	DSER OI 5.3.3-1 (R2)
5.4	5.4-76	NRC Generic Letter GL-97-06
5.4	5.4-82	Editorial
5.4	5.4-89	Editorial
5.4	5.4-94	DSER OI 5.3.3-1 (R2) Editorial
5.4	5.4-102	Editorial
5.4	5.4-103	DSER OI 5.3.3-1 (R2)
VOLUME 6		
6, T of C	ii	Editorial
6, T of C	v through vii	Editorial
6.2	6.2-3	Editorial
6.2	6.2-14	Editorial
6.2	6.2-22	Editorial
6.2	6.2-42	Editorial
6.2	6.2-51	Editorial
6.2	6.2-55 through 6.2-57	Editorial
6.2	6.2-97	Editorial
6.3	6.3-44	NRC Audit (Nov. 18-20) Action Item 5
6.3	6.3-51	Editorial
6.4	6.4-8 and 6.4-9	DSER OI 2.3.4-1 (R3)
VOLUME 7		
9, T of C	iii through viii	Editorial
9, T of C	x through xii	Editorial
9.3	9.3-21	NRC CIP Team Comment
9.3	9.3-27	NRC CIP Team Comment
9.3	9.3-51	Editorial

TIER 2 REVISION 8 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
VOLUME 8		
9.5	9.5-3 and 9.5-4	DSER OI 9.5.1-1 (R2), Addendum A
9.5	9.5-34	DSER OI 9.5.1-1 (R2), Addendum B
9.5	9.5-39	DSER OI 9.5.1-1 (R2), Addendum A DSER OI 9.5.1-1 (R2), Addendum B
9.5	9.5-46	Editorial
Appendix 9A	9A-3	Editorial
Appendix 9A	9A-34	DSER OI 9.5.1-1 (R2), Addendum B
Appendix 9A	9A-41	Editorial
Appendix 9A	9A-70 and 9A-71	DSER OI 9.5.1-1 (R2), Addendum A
Appendix 9A	9A-82 and 9A-83	DSER OI 9.5.1-1 (R2), Addendum A
Appendix 9A	9A-87 and 9A-88	DSER OI 9.5.1-1 (R2), Addendum A
Appendix 9A	9A-96	Editorial
Appendix 9A	9A-97 and 9A-98	DSER OI 9.5.1-1 (R2), Addendum A
Appendix 9A	9A-100	DSER OI 9.5.1-1 (R2), Addendum A
Appendix 9A	9A-141 through 9A-162	Editorial
Appendix 9A	9A-195 through 9A-209	DSER OI 9.5.1-1 (R2), Addendum A
VOLUME 9		
12.1	12.1-4	Editorial
12.1	12.1-6	Editorial
12.3	12.3-41 through 12.3-45	DSER OI 9.5.1-1 (R2)
12.3	12.3-65	Drawing note clarification
12.3	12.3-73 through 12.3-77	DSER OI 9.5.1-1 (R2)
12.3	12.3-103 through 12.3-107	DSER OI 9.5.1-1 (R2)

TIER 2 REVISION 8 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change(1)
13, T of C	i	Editorial
13	13-2	Editorial
13	13-3 and 13-4	References deleted for clarification
13	13-6	References deleted for clarification Editorial
13	13-8	References deleted for clarification
14.2	14.2-20	NRC Audit (Nov. 18-20) Action Item 5
14.3	14.3-4	Editorial
14.3	14.3-20	Editorial
14.3	14.3-23	NRC Audit (Nov. 18-20) Action Item 5
14.3	14.3-51	Editorial
VOLUME 10		
15, T of C	vii	Editorial
15, T of C	ix	Editorial
15, T of C	xxi	Editorial
15.6	15.6-194	NRC Audit (Nov. 18-20) Action Item 2
Appendix 15A	15A-15	DSER OI 2.3.4-1 (R3)
Appendix 15A	15A-17 and 15A-18	DSER OI 2.3.4-1 (R3)
Appendix 15B	15B-2 through 15B-4	DSER OI 15.3-1 (R1)
Appendix 15B	15B-7	DSER OI 15.3-1 (R1)
Appendix 15B	15B-9	DSER OI 15.3-1 (R1)
VOLUME 11		
16.1	ii and iii	Editorial
16.1	v	Editorial
16.1	3.4.14-1 through 3.4.14-3	DSER OI 5.3.3-1 (R2)
16.1	3.5.1-1	DSER OI 16.2-2 (R1)
16.1	3.5.2-1	DSER OI 16.2-2 (R1)

TIER 2 REVISION 8 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
16.1	3.5.6-2	DSER OI 16.2-2 (R1) Editorial
16.1	3.5.7-1	DSER OI 16.2-2 (R1)
16.1	3.5.8-1	DSER OI 16.2-2 (R1)
16.1	3.5.8-2	Editorial
16.1	5.5-13	Editorial
16.1	B 3.4.14-3 through B 3.4.14-5	DSER OI 5.3.3-1 (R2)
16.1	B 3.4.14-7	DSER OI 5.3.3-1 (R2)
16.1	B 3.5.1-4	DSER OI 16.2-2 (R1)
16.1	B 3.5.2-4 and B 3.5.2-5	DSER OI 16.2-2 (R1)
16.1	B 3.5.2-8	Editorial
16.1	B 3.5.6-4 and B 3.5.6-5	DSER OI 16.2-2 (R1)
16.1	B 3.5.7-2	DSER OI 16.2-2 (R1)
16.1	B 3.5.8-2	DSER OI 16.2-2 (R1)
16.1	B 3.6.4-1	Editorial
VOLUME 12		
17	17-1	Editorial
17	17-10	DSER OI 17.5-1 (R1)
17	17-22	Editorial
18.1	18.1-4	DSER OI 14.3.3-14 DSER OI 14.3.3-15 DSER OI 14.3.3-16 DSER OI 18.11.3.5-2 DSER OI 18.11.3.5-3 DSER OI 18.11.3.5-4
18.8	18.8-25	DSER OI 14.3.3-14 DSER OI 14.3.3-15 DSER OI 14.3.3-16 DSER OI 18.11.3.5-2 DSER OI 18.11.3.5-3 DSER OI 18.11.3.5-4
18.11	18.11-1	DSER OI 14.3.3-14 DSER OI 14.3.3-15 DSER OI 14.3.3-16 DSER OI 18.11.3.5-2 DSER OI 18.11.3.5-3 DSER OI 18.11.3.5-4

TIER 2 REVISION 8 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
19, T of C	iv through xii	Editorial
19.55	19.55-6	DSER OI 19A.2-8 (R2)
19.55	19.55-9	Editorial
19.59	19.59-36	Editorial
19.59	19.59-37	DSER OI 19A.2-7 (R2)
19.59	19.59-45	Editorial
19.59	19.59-77	Editorial
19.59	19.59-81	Editorial
19.59	19.59-83	Editorial
19.59	19.59-90	Editorial
Appendix 19E	19E-6	Editorial
Appendix 19E	19E-26	Editorial
Appendix 19E	19E-37 through 19E-39	DSER OI 5.3.3-1 (R2)
Appendix 19E	19E-44	Editorial
Appendix 19E	19E-47 and 19E-48	Editorial
Appendix 19E	19E-49	DSER OI 5.3.3-1 (R2)
Appendix 19E	19E-62 through 19E-78	DSER OI 5.3.3-1 (R2)

1. Changes incorporated as a result of Draft Safety Evaluation Report (DSER) Open Item (OI) Response identified by DSER OI number.

TIER 2 REVISION 9 CHANGE ROADMAP

Section	Page No.	Type of Change[1]
VOLUME 2		
Tier 2 List of Effective Pages	1 through 36	Editorial
Master T of C	i through xxxii	Editorial
Tier 2 Revision 9 Change Roadmap	xcviii through ciii	Editorial
1, T of C	iii and iv	Editorial
1.2	1.2-35 and 1.2-37	Technical
1.2	1.2-55 and 1.2-57	Technical
1.2	1.2-71	Technical
1.6	1.6-4	DSER OI 1.10-1 (R1)
1.6	1.6-7 through 1.6-12	Editorial
1.6	1.6-13	DSER OI 1.10-1 (R1)
1.6	1.6-14 through 1.6-21	Editorial
1.8	1.8-3	Editorial
1.8	1.8-15	DSER OI 13.6-1 (R1)
1.9	1.9-65	DSER OI 1.10-1 (R1)
1.9	1.9-98	Editorial
1.9	1.9-100	Editorial
1.9	1.9-102	DSER OI 1.10-1 (R1)
Appendix 1B	1B-2 and 1B-3	DSER OI 19.4-1 (R3), Attachment 2
Appendix 1B	1B-6	Editorial
Appendix 1B	1B-7	DSER OI 19.4-1 (R3), Attachment 2
Appendix 1B	1B-9	DSER OI 19.4-1 (R3), Attachment 2
Appendix 1B	1B-12	Editorial
Appendix 1B	1B-13 through 1B-17	DSER OI 19.4-1 (R3), Attachment 2
Appendix 1B	1B-19 through 1B-23	DSER OI 19.4-1 (R3), Attachment 2

TIER 2 REVISION 9 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
VOLUME 3		
2, T of C	i	Editorial
2	2-4	Clarification of COL Item
3, T of C	v	Editorial
3, T of C	xv through xvii	Editorial
3, T of C	xx	Editorial
3.6	3.6-34	DSER OI 3.6.3.4-2, Addendum 2
3.6	3.6-35	DSER OI 3.6.3.4-2, Addendum 2 Editorial
3.7	3.7-133	Technical
3.7	3.7-147	Technical
VOLUME 4		
3.8	3.8-1	Editorial
3.8	3.8-59	DSER OI 3.8.5.1-1 (R2)
3.8	3.8-61	DSER OI 3.8.5.1-1 (R2) Editorial (per Dec. 15–16 meeting)
3.8	3.8-62	Editorial (per Dec. 15–16 meeting)
3.8	3.8-64	Editorial
3.8	3.8-66 and 3.8-67	Editorial
3.8	3.8-83	Editorial (per Dec. 15–16 meeting)
3.8	3.8-94	Editorial
3.8	3.8-120 and 3.8-121	Technical
3.8	3.8-125	Technical
VOLUME 5		
5, T of C	ii	Editorial
5.2	5.2-5	Editorial
5.2	5.2-7 through 5.2-9	Editorial

TIER 2 REVISION 9 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
5.2	5.2-10	DSER OI 5.2.3-2 (R2)
5.2	5.2-30	DSER OI 1.10-1 (R1) Editorial
5.3	5.3-35	Technical
VOLUME 6		
6, T of C	ii and iii	Editorial
6, T of C	vi and vii	Editorial
6.2	6.2-134	Technical
6.2	6.2-136	Technical
6.3	6.3-14	DSER OI 15.2.7-1 Item 7 (R4), Addendum Editorial
6.3	6.3-19 and 6.3-20	DSER OI 6.2.1.8.3-3 (R2)
6.3	6.3-49 and 6.3-50	DSER OI 6.2.1.8.3-4 (DSER OI 6.2.1.8.3-1 [R3])
6.3	6.3-53	DSER OI 6.2.1.8.3-3 (R2)
6.3	6.3-58	Editorial
6.3	6.3-61	DSER OI 6.2.1.8.3-3 (R2)
7, T of C	i	Editorial
7, T of C	v	Editorial
7.1	7.1-22	DSER OI 1.10-1 (R1)
7.2	7.2-15	Editorial
7.2	7.2-16	DSER OI 1.10-1 (R1)
VOLUME 7		
9, T of C	i	Editorial
9, T of C	ix	Editorial
9, T of C	xi	Editorial
9.1	9.1-11	Editorial
9.1	9.1-40	Editorial
9.1	9.1-42	DSER OI 1.10-1 (R1) COL, Action Item
9.1	9.1-43	Editorial

TIER 2 REVISION 9 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
9.1	9.1-47	Editorial
9.1	9.1-60	Editorial
VOLUME 8		
9.5	9.5-15	DSER OI 19.1.10.2-6 (R2)
Appendix 9A	9A-34	DSER OI 9.5.1-1 (R4), Addendum D
Appendix 9A	9A-75	Design Change
Appendix 9A	9A-150	Design Change
Appendix 9A	9A-154	Design Change
Appendix 9A	9A-167 and 9A-169	Technical
Appendix 9A	9A-183	Technical
Appendix 9A	9A-195	Technical
VOLUME 9		
12.3	12.3-27 and 12.3-29	Technical
12.3	12.3-49	Technical
12.3	12.3-59 and 12.3-61	Technical
12.3	12.3-81	Technical
12.3	12.3-89 and 12.3-91	Technical
12.3	12.3-111	Technical
13, T of C	i	Editorial
13	13-1	COL, Action Item
13	13-2	DSER OI 1.10-1 (R1)
13	13-7	Editorial
13	13-8	DSER OI 1.10-1 (R1) DSER OI 13.6-1 (R1) Editorial
14.2	14.2-36 and 14.2-37	DSER OI 1.10-1 (R1)
14.2	14.2-115	DSER OI 14.2.10-1 (R4)
14.3	14.3-21 and 14.3-22	Editorial
14.3	14.3-23	DSER OI 15.2.7-1 Item 7 (R4), Addendum Editorial
14.3	14.3-27 and 14.3-28	Editorial
14.3	14.3-31 and 14.3-32	Editorial

TIER 2 REVISION 9 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
14.3	14.3-35 and 14.3-36	Editorial
14.3	14.3-38	Editorial
14.3	14.3-40 and 14.3-41	Editorial
14.3	14.3-44 and 14.3-45	Editorial
14.3	14.3-47	Editorial
14.4	14.4-1	DSER OI 1.10-1 (R1) Editorial
14.4	14.4-2	DSER OI 1.10-1 (R1)
VOLUME 10		
15, T of C	v	Editorial
15, T of C	viii and ix	Editorial
15, T of C	xviii through xxii	Editorial
15.1	15.1-13	Editorial
15.1	15.1-25	Editorial
15.6	15.6-33 through 15.6-37	DSER OI 21.5-2
15.6	15.6-39	DSER OI 15.2.7-1 Item 7 (R5) DSER OI 21.5-2
15.6	15.6-42	DSER OI 15.2.7-1 Item 7 (R5) DSER OI 21.5-2
15.6	15.6-44	DSER OI 15.2.7-1 Item 7 (R5)
15.6	15.6-45	DSER OI 21.5-2
15.6	15.6-46 and 15.6-47	DSER OI 15.2.7-1 Item 7 (R5) DSER OI 21.5-2
15.6	15.6-48 and 15.6-49	DSER OI 21.5-2
15.6	15.6-50	DSER OI 15.2.7-1 Item 7 (R5) DSER OI 21.5-2
15.6	15.6-51	DSER OI 15.2.7-1 Item 7 (R5) DSER OI Post LOCA Boron (R1)
15.6	15.6-52 and 15.6-53	DSER OI Post LOCA Boron (R1)
15.6	15.6-55 and 15.6-56	DSER OI 21.5-2
15.6	15.6-60	Editorial
15.6	15.6-65	Editorial
15.6	15.6-76	DSER OI 15.2.7-1 Item 7 (R5) DSER OI 21.5-2
15.6	15.6-77	DSER OI 15.2.7-1 Item 7 (R5)
15.6	15.6-79	DSER OI 21.5-2

TIER 2 REVISION 9 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
15.6	15.6-147 through 15.6-166	DSER OI 15.2.7-1 Item 7 (R5)
15.6	15.6-167 through 15.6-186	DSER OI 15.2.7-1 Item 7 (R5) DSER OI 21.5-2
15.6	15.6-210 through 15.6-221	DSER OI 21.5-2
15.6	15.6-222 through 15.6-235	DSER OI 21.5-2
15.6	15.6-236 through 15.6-249	DSER OI 15.2.7-1 Item 7 (R5)
15.6	15.6-250 through 15.6-263	DSER OI 15.2.7-1 Item 7 (R5)
VOLUME 11		
VOLUME 12		
17	17-5	Editorial
17	17-10	DSER OI 1.10-1 (R1)
17	17-15	DSER OI CIP Issue 7
17	17-22	Editorial
19.55	19.55-2	Editorial (per Dec. 15–16 meeting)
19.55	19.55-4 through 19.55-7	Editorial (per Oct. 6–9 meeting)

1. Changes incorporated as a result of Draft Safety Evaluation Report (DSER) Open Item (OI) Responses identified by DSER OI number. DSER OI number in parentheses contains a reference to the DSER OI response listed above.

TIER 2 REVISION 10 CHANGE ROADMAP

Section	**Page No.**	**Type of Change**[1]
VOLUME 2		
Tier 2 List of Effective Pages	1 through 36	Editorial
Master T of C	i through xxxii	Editorial
Tier 2 Revision 10 Change Roadmap	civ through cvii	Editorial
1.2	1.2-29	Technical
1.6	1.6-13	Editorial
1.8	1.8-14	Editorial
1.8	1.8-17	NRC Comments
1.9	1.9-2	DSER OI 13.6-1 (R2)
1.9	1.9-20	NRC Comments
1.9	1.9-25	DSER OI 1.9 – USI/GSI Item
1.9	1.9-58	NRC Comments
1.9	1.9-119	NRC Comments
1.9	1.9-121	NRC Comments
1.9	1.9-125	NRC Comments
1.9	1.9-128	NRC Comments
1.9	1.9-154 through 1.9-156	NRC Comments
VOLUME 3		
2	2-3	DSER OI 15.3-1 (R4)
2	2-15 and 2-16	DSER OI 15.3-1 (R4)
3.6	3.6-12 through 3.6-14	Tier 2* for Piping DAC
3.6	3.6-20 and 3.6-21	Tier 2* for Piping DAC
3.6	3.6-33 and 3.6-34	Tier 2* for Piping DAC
3.7	3.7-19 and 3.7-20	Tier 2* for Piping DAC
3.7	3.7-24	Tier 2* for Piping DAC
3.7	3.7-30 and 3.7-31	Tier 2* for Piping DAC
3.7	3.7-35 and 3.7-36	Tier 2* for Piping DAC
3.7	3.7-51	Tier 2* for Piping DAC

TIER 2 REVISION 10 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[(1)]
VOLUME 4		
3.8	3.8-4	Editorial
3.9	3.9-26 and 3.9-27	Tier 2* for Piping DAC
3.9	3.9-46	Tier 2* for Piping DAC
3.9	3.9-54 and 3.9-55	Tier 2* for Piping DAC
3.9	3.9-59	Tier 2* for Piping DAC
3.9	3.9-61 through 3.9-63	Tier 2* for Piping DAC
3.9	3.9-65	Tier 2* for Piping DAC
3.9	3.9-102 through 3.9-105	Tier 2* for Piping DAC
3.9	3.9-106	Tier 2* for Piping DAC Editorial
3.9	3.9-108	Tier 2* for Piping DAC
3.9	3.9-110	Tier 2* for Piping DAC
VOLUME 5		
4.3	4.3-2	NRC Comments
4.3	4.3-44	Editorial
4.3	4.3-48 and 4.3-49	Editorial
4.3	4.3-51	Editorial
4.3	4.3-54	Editorial
5, T of C	ii	Editorial
5, T of C	iv	Editorial
5.2	5.2-3	Tier 2* for Piping DAC
5.2	5.2-9 and 5.2-10	DSER OI 5.2.3-2 (R3)
5.2	5.2-25 and 5.2-26	DSER OI 3.6.3.4-2 (R1) Addendum 2
5.2	5.2-29 and 5.2-30	DSER OI 3.6.3.4-2 (R1) Addendum 2
5.2	5.2-31	DSER OI 4.5.1-1 (R2)
5.2	5.2-32 through 5.2-34	DSER OI 5.2.3-2 (R3)
5.2	5.2-36	Tier 2* for Piping DAC
5.2	5.2-37	DSER OI 3.6.3.4-2 (R1) Addendum 2
5.4	5.4-52 through 5.4-55	NRC Comments
5.4	5.4-56	Editorial
5.4	5.4-58 and 5.4-59	NRC Comments

TIER 2 REVISION 10 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
VOLUME 6		
6.1	6.1-1	DSER OI 5.2.3-2 (R3)
6.1	6.1-13	Editorial
6.2	6.2-38	Clarification
6.2	6.2-127	Editorial
6.4	6.4-8	DSER OI 15.3-1 (R4)
7.1	7.1-22	Editorial
VOLUME 7		
9.1	9.1-42	Response to NRC Comment
9.4	9.4-16	DSER OI 15.3-1 (R4)
9.4	9.4-72	NRC Comments
9.4	9.4-74	NRC Comments
9.4	9.4-77	DSER OI 15.3-1 (R4)
VOLUME 8		
9.5	9.5-16	NRC Comment
9.5	9.5-75 and 9.5-77	Editorial
VOLUME 9		
11, T of C	i	Editorial
11.2	11.2-13	Editorial
11.2	11.2-22	Editorial
11.2	11.2-35	Editorial
11.2	11.2-37	Editorial
11.2	11.2-41	Editorial
11.2	11.2-43	DSER OI 3.6.3.4-2 (R1) Addendum 2
13	13-8	DSER OI 13.6-1 (R2)
VOLUME 10		
15, T of C	vii	Editorial
15, T of C	ix	Editorial

TIER 2 REVISION 10 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
15.6	15.6-22 and 15.6-23	DSER OI 15.3-1 (R4)
15.6	15.6-25	NRC Comments
15.6	15.6-33 and 15.6-34	NRC Comments
15.6	15.6-36	DSER OI 21.5-2
15.6	15.6-44	NRC Comments
15.6	15.6-49	NRC Comments
15.6	15.6-54	NRC Comments
15.6	15.6-65 and 15.6-66	DSER OI 15.3-1 (R4)
Appendix 15A	15A-14 and 15A-15	DSER OI 15.3-1 (R4)
Appendix 15B	15B-5	DSER OI 15.3-1 (R4)
Appendix 15B	15B-7 and 15B-8	DSER OI 15.3-1 (R4)
Appendix 15B	15B-10 through 15B-12	DSER OI 15.3-1 (R4)
VOLUME 11		
16.1	ii through iv	Editorial
16.1	vi	Editorial
16.1	3.4.9-1 through 3.4.9-3	DSER OI 3.6.3.4-2 (R2) Addendum 2
16.1	3.7.8-1	Editorial
16.1	B 3.4.9-1 through 3.4.9-5	DSER OI 3.6.3.4-2 (R2) Addendum 2
16.1	B 3.4.9-7	Editorial
16.1	B 3.7.6-7	NRC Comments
VOLUME 12		
17	17-10	Editorial
19.59	19.59-4	Editorial
19.59	19.59-9	Editorial
19.59	19.59-98	DSER OI 19.1.10.2-1 (R2)

1. Changes incorporated as a result of Draft Safety Evaluation Report (DSER) Open Item (OI) Responses identified by DSER OI number.

TIER 2 REVISION 11 CHANGE ROADMAP

Section	Page No.	Type of Change[1]
VOLUME 2		
Tier 2 List of Effective Pages	1 through 36	Editorial
Master T of C	i through xxxii	Editorial
Tier 2 Revision 11 Change Roadmap	cviii through cxi	Editorial
1.6	1.6-12	Editorial
1.7	1.7-4 and 1.7-5	NRC Comments
1.9	1.9-37	DSER OI May 6, 2004 Security Telecon
1.9	1.9-109	NRC Comments
1.9	1.9-121	NRC Comments
Appendix 1A	1A-3	Editorial
VOLUME 3		
3.7	3.7-22 through 3.7-25	Tier 2* for Piping DAC
3.7	3.7-27 through 3.7-33	Tier 2* for Piping DAC
3.7	3.7-36	Tier 2* for Piping DAC
3.7	3.7-40 through 3.7-43	Tier 2* for Piping DAC
3.7	3.7-44	Tier 2* for Piping DAC NRC Comments
VOLUME 4		
3.9	3.9-3	Tier 2* for Piping DAC
3.9	3.9-44	Tier 2* for Piping DAC
3.9	3.9-48	Tier 2* for Piping DAC
3.9	3.9-52 through 3.9-55	Tier 2* for Piping DAC
3.9	3.9-59	Tier 2* for Piping DAC
3.9	3.9-61 and 3.9-62	Tier 2* for Piping DAC
3.9	3.9-64	Tier 2* for Piping DAC
3.9	3.9-92 and 3.9-93	Tier 2* for Piping DAC
3.9	3.9-121 through 3.9-161	Editorial

TIER 2 REVISION 11 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
VOLUME 5		
4, T of C	iii	Editorial
4.5	4.5-1 through 4.5-4	Editorial for Pagination
5, T of C	ii	Editorial
5.1	5.1-5	Technical Editorial
5.2	5.2-2 and 5.2-3	Tier 2* for Piping DAC
5.2	5.2-30	NRC Comment on DSER OI 3.6.3.4-2 Addendum 2, Revision 1 Response
5.4	5.4-2 and 5.4-3	Technical
5.4	5.4-78	Technical Editorial
5.4	5.4-81	Editorial
VOLUME 6		
6.2	6.2-2 and 6.2-3	DSER OI May 5, 2004 Containment Pressure Telecon
6.2	6.2-38	Editorial
6.2	6.2-50	Editorial
6.2	6.2-107 through 6.2-109	Editorial
6.3	6.3-17	Editorial
6.3	6.3-19	NRC Comments
6.3	6.3-38	Editorial
Appendix 6A	6A-1	Editorial
Appendix 6A	6A-3	Editorial
Appendix 6A	6A-9	Editorial
VOLUME 7		
8.3	8.3-2	Technical
8.3	8.3-28 and 8.3-29	Technical
8.3	8.3-34	Editorial
8.3	8.3-35	Technical

TIER 2 REVISION 11 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
9.2	9.2-47 and 9.2-48	Technical
9.2	9.2-59 and 9.2-61	Technical
9.4	9.4-16	NRC Comments
9.4	9.4-74	NRC Comments
9.4	9.4-75	NRC Comment on DSER OI 15.3-1 (R4) Response
VOLUME 8		
VOLUME 9		
13	i	Editorial
13	13-4	NRC Comments
13	13-5 and 13-6	DSER OI May 6, 2004 Security Telecon
13	13-7	NRC Comments
13	13-8	DSER OI May 6, 2004 Security Telecon
14.3	14.3-15	NRC Comments
VOLUME 10		
15, T of C	iii	Editorial
15.2	15.2-6	Editorial
15.2	15.2-12 and 15.2-13	Editorial
15.2	15.2-15	Editorial
15.2	15.2-17	Editorial
15.6	15.6-22	NRC Comments on Tracking Item 26
VOLUME 11		
16.1	iv	Editorial
16.1	B 3.4.4-1	Technical

TIER 2 REVISION 11 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
VOLUME 12		
18, T of C	i	Editorial
18.2	18.2-14	NRC Comments
18.12	18.12-1 through 18.12-3	NRC Comments
18.12	18.12-5 and 18.12-6	NRC Comments Editorial
18.12	18.12-7	NRC Comments
18.12	18.12-9	Editorial
19, T of C	ii and iii	Editorial
19, T of C	ix	Editorial
19, T of C	xi	Editorial
19.34	19.34-1	Editorial
19.39	19.39-1	Editorial
19.39	19.39-3	Editorial
19.39	19.39-7	Editorial
19.41	19.41-1 through 19.41-11	Editorial for Pagination
Appendix 19D	19D-20 through 19D-26	Editorial

1. Changes incorporated as a result of Draft Safety Evaluation Report (DSER) Open Item (OI) Responses identified by DSER OI number.

TIER 2 REVISION 12 CHANGE ROADMAP

Section	Page No.	Type of Change[1]
VOLUME 2		
Tier 2 List of Effective Pages	1 through 36	Editorial
Master T of C	i through xxxii	Editorial
Tier 2 Revision 12 Change Roadmap	cxii and cxiii	Editorial
VOLUME 3		
2	2-15 and 2-16	DSER OI 15.3-1 (R5)
3, T of C	x	Editorial
3, T of C	xv	Editorial
3, T of C	xvii	Editorial
3, T of C	xxiii	Editorial
3.2	3.2-20 through 3.2-84	Editorial
VOLUME 4		
3.8	3.8-176 through 3.8-180	Elevations corrected to be consistent with data provided on Figure 3.7.2-12. Format revised similar to that provided in Figure 3.8.3-1.
3.9	3.9-45	NRC Comments
VOLUME 5		
Appendix 3D	3D-39 through 3D-44	Editorial
Appendix 3D	3D-87	Editorial
Appendix 3H	3H-50	Figure corrected to be consistent with data provided on Sheets 1 and 2 of this figure.
VOLUME 6		
6.4	6.4-8	DSER OI 15.3-1 (R5)

TIER 2 REVISION 12 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
7, T of C	iii	Editorial
7.4	7.4-1	Editorial
7.4	7.4-4	Editorial
7.4	7.4-9	Editorial
7.6	7.6-5	Consistency with DCD Chapter 16
VOLUME 7		
9.4	9.4-77	DSER OI 15.3-1 (R5)
VOLUME 9		
14.2	14.2-56	NRC Comments
VOLUME 10		
15.6	15.6-23	DSER OI 15.3-1 (R5)
15.6	15.6-65 and 15.6-66	DSER OI 15.3-1 (R5)
Appendix 15A	15A-14 and 15A-15	DSER OI 15.3-1 (R5)
Appendix 15B	15B-8	DSER OI 15.3-1 (R5)
Appendix 15B	15B-10 through 15B-12	DSER OI 15.3-1 (R5)

1. Changes incorporated as a result of Draft Safety Evaluation Report (DSER) Open Item (OI) Responses identified by DSER OI number.

TIER 2 REVISION 13 CHANGE ROADMAP

Section	Page No.	Type of Change
VOLUME 2		
Tier 2 List of Effective Pages	1 through 36	Editorial
Master T of C	i through xxxii	Editorial
Tier 2 Revision 13 Change Roadmap	cxiv and cxv	Editorial
1.6	1.6-4	NRC Comments
1.6	1.6-14	NRC Comments Editorial
1.6	1.6-15 and 1.6-16	Editorial
1.6	1.6-18	Editorial
1.6	1.6-21	Editorial
1.8	1.8-14	NRC Comments
1.8	1.8-17	NRC Comments
1.9	1.9-35	NRC Comments
1.9	1.9-38	Editorial
1.9	1.9-64	Editorial
1.9	1.9-102	NRC Comments
VOLUME 3		
VOLUME 4		
VOLUME 5		
VOLUME 6		
6.3	6.3-49	ACRS Comment
VOLUME 7		
VOLUME 8		
9.5	9.5-15	NRC Comments

TIER 2 REVISION 13 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
VOLUME 9		
VOLUME 10		
15.0	15.0-12	NRC Comments
15.0	15.0-15	Editorial
15.6	15.6-25	NRC Comments
VOLUME 11		
16.1	16.1-1	Editorial
16.1	i through vi	Editorial
16.1	1.4-8	Editorial
16.1	3.1.4-1	Editorial
16.1	3.1.7-1 and 3.1.7-2	Editorial
16.1	3.1.8-2	Editorial
16.1	3.3.1-12 through 3.3.1-15	Editorial
16.1	3.3.2-14 through 3.3.2-26	Editorial
16.1	3.4.9-1	Editorial
16.1	3.6.6-2	NRC Comments
16.1	3.7.2-3	Editorial
16.1	3.7.10-1	Editorial
16.1	3.8.1-1	Editorial
16.1	3.9.5-2	Editorial
16.1	3.9.7-1	Editorial
16.1	B 3.1.1-4 and B 3.1.1-5	Editorial
16.1	B 3.3.2-46	Editorial
16.1	B 3.4.11-1 through B 3.4.12-4	Reformatted due to Pagination
16.1	B 3.6.6-5 and B 3.6.6-6	NRC Comments
16.1	B 3.6.8-1 through B 3.6.8-9	Reformatted due to Pagination
16.1	B 3.7.3-4	Editorial
16.1	B 3.7.8-2	Editorial
16.1	B 3.9.4-1	Editorial
VOLUME 12		
19.59	19.59-37	NRC Comments
19.59	19.59-92	NRC Comments
19.59	19.59-98	NRC Comments

TIER 2 REVISION 14 CHANGE ROADMAP

Section	Page No.	Type of Change
VOLUME 2		
Tier 2 List of Effective Pages	1 through 36	Editorial
Master T of C	i through xxxii	Editorial
Tier 2 Revision 14 Change Roadmap	cxvi and cxviii	Editorial
1.5	1.5-1 and 1.5-2	Editorial
1.5	1.5-4	Editorial
1.5	1.5-6	Editorial
1.5	1.5-8 and 1.5-9	Editorial
1.6	1.6-2 through 1.6-18	Editorial
1.6	1.6-20 and 1.6-21	Editorial
1.9	1.9-102	Editorial
Appendix 1A	1A-68	Editorial
VOLUME 3		
3.6	3.6-18	Editorial
3.6	3.6-35	Editorial
VOLUME 4		
3.8	3.8-65 and 3.8-66	Editorial
3.9	3.9-12	NRC Comments
3.9	3.9-94	Editorial
VOLUME 5		
4.1	4.1-5	Editorial
4.1	4.1-9	Editorial
4.2	4.2-2	Editorial
4.2	4.2-11	Editorial
4.2	4.2-35 through 4.2-37	Editorial
4.3	4.3-39 through 4-43	Editorial
4.3	4.3-48	Editorial

TIER 2 REVISION 14 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
4.4	4.4-31 through 4.4-33	Editorial
4.4	4.4-35	Editorial
4.4	4.4-37	Editorial
5.1	5.1-10	NRC Comments
5.3	5.3-7	NRC Comments
5.3	5.3-13	NRC Comments
5.3	5.3-23	NRC Comments
5.3	5.3-24	Editorial
VOLUME 6		
6.1	6.1-9	NRC Comments
6.2	6.2-49 and 6.2-50	Editorial
Appendix 6A	6A-8 and 6A-9	Editorial
7.1	7.1-22 and 7.1-23	Editorial
VOLUME 7		
VOLUME 8		
9.5	9.5-31	Editorial
10.4	10.4-56	Editorial
VOLUME 9		
13	13-6	NRC Comments
14.2	14.2-32	Editorial
VOLUME 10		
15.0	15.0-10	Editorial
15.0	15.0-15	Editorial
15.1	15.1-24	Editorial

TIER 2 REVISION 14 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
15.2	15.2-21	Editorial
15.3	15.3-11	Editorial
15.4	15.4-38 and 15.4-39	Editorial
15.6	15.6-55 and 15.6-56	Editorial
VOLUME 11		
16.1	iii and iv	Editorial
16.1	5.6-3 and 5.6-4	Editorial
16.1	B 3.2.1-10	Editorial
16.1	B 3.2.3-4	Editorial
16.1	B 3.3.1-48	Editorial
16.1	B 3.3.2-68	Editorial
VOLUME 12		
Appendix 19D	19D-18	Editorial
Appendix 19E	19E-44	Editorial

TIER 2 REVISION 15 CHANGE ROADMAP

TIER 2 REVISION 15 CHANGE ROADMAP (Cont.)

Section	Page No.	Type of Change[1]
VOLUME 7		
9, T of C	i	Editorial
9, T of C	ix	Editorial
9, T of C	xi	Editorial
9.1	9.1-18 through 9.1-20	Technical
VOLUME 8		
9.5	9.5-77	Technical
Appendix 9A	9A-22	Technical
Appendix 9A	9A-24	Technical
Appendix 9A	9A-128 and 9A-129	Technical
Appendix 9A	9A-131	Technical
VOLUME 9		
14.2	14.2-15	Technical
14.2	14.2-102	Technical
14.2	14.2-121	Technical
VOLUME 10		
15.0	15.0-23	Technical
15.3	15.3-1	Technical
15.3	15.3-4	Technical
15.3	15.3-12	Technical
15.3	15.3-17 through 15.3-21	Technical
15.3	15.3-30 through 15.3-34	Technical
VOLUME 11		
16.1	i	Editorial
16.1	iv	Editorial
16.1	3.3.1-13	Technical
16.1	B 3.3.1-24	Technical
16.1	B 3.3.1-34	Technical
VOLUME 12		

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

LIST OF TABLES

LIST OF FIGURES

CHAPTER 1

INTRODUCTION AND GENERAL DESCRIPTION OF THE PLANT

1.1 Introduction

This Design Control Document (DCD) for a simplified passive advanced light water reactor plant is submitted to the NRC for review and approval under the provisions of 10 CFR Part 52. Westinghouse is requesting NRC issuance of a Safety Evaluation Report (SER) and Final Design Approval for the AP1000. This DCD also is submitted as part of the application for design certification of the AP1000 in accordance with 10 CFR 52 Subpart B.

1.1.1 Plant Location

The AP1000 is a standardized plant that is to be placed on a site with parameters described in Chapter 2, "Site Characteristics". The site parameters relate to the seismology, hydrology, meteorology, geology, heat sink, and other site-related aspects.

1.1.2 Containment Type

The containment building is a freestanding, cylindrical, steel containment vessel with elliptical upper and lower heads. It is surrounded by a seismic Category I reinforced concrete shield building. The containment vessel is an integral part of the passive containment cooling system. The vessel provides the safety-related interface with the ultimate heat sink, which is the surrounding atmosphere. Westinghouse is responsible, along with their contractor team members, for the design of the containment.

1.1.3 Reactor Type

The nuclear steam supply system (NSSS) for the AP1000 is a Westinghouse-designed pressurized water reactor.

1.1.4 Power Output

The plant's net producible electrical power to the grid is at least 1000 MWe, with a core power rating of 3400 MWt. In some safety evaluations a power level higher than the rated power level is employed.

1.1.5 Schedule

The scheduled completion date and estimated commercial operation date of nuclear power plants referencing the AP1000 design certification are provided by the Combined License applicant.

1.1.6 Format and Content

1.1.6.1 Regulatory Guide 1.70

To the extent practical, the AP1000 DCD has used as a guide the format and content recommendations of Regulatory Guide 1.70, Revision 3, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants - LWR Edition," November 1978.

The DCD generally uses the same chapter, section, subsection, and paragraph headings used in the standard format. Where appropriate, the DCD is subdivided beyond the extent of the standard format to provide additional information specifically required for that area. Similarly, some of the passive features of the AP1000 require modification of the standard format and content either in terms of placement or type of material presented.

1.1.6.2 Standard Review Plan

The technical guidance provided in NUREG-0800, is followed in the preparation of the AP1000 DCD. Standard Review Plan conformance is also determined in accordance with 10 CFR 50.34 to identify the deviations of the AP1000 DCD from the Standard Review Plan. See subsection 1.9.2 for additional details on Standard Review Plan conformance.

1.1.6.3 Text, Tables and Figures

AP1000 DCD tables of data are identified by the section or subsection number followed by a sequential number (for example, Table 3.3-5 is the fifth table of Section 3.3). Tables are located at the end of the section immediately following the text. Drawings, pictures, sketches, curves, graphs, plots, and engineering diagrams are identified as figures and are numbered sequentially by section or subsection similar to tables, and follow at the end of the applicable section or subsection.

1.1.6.4 Numbering of Pages

Text pages are numbered sequentially within each section or subsection.

1.1.6.5 Proprietary Information

The AP1000 DCD contains no proprietary information.

1.1.6.6 DCD Acronyms

Table 1.1-1 provides a list of acronyms used in the AP1000 DCD. Acronyms for systems are defined in the section in which they are used. Other acronyms may be defined in the section in which they are used. Table 1.7-2 provides a list of AP1000 system designators.

1.1.7 Combined License Information

Combined License applicants referencing the AP1000 certified design will provide the construction and startup schedule information.

Table 1.1-1 (Sheet 1 of 4)

AP1000 DCD ACRONYMS

ac	-	Alternating Current
ACI	-	American Concrete Institute
ACRS	-	Advisory Committee on Reactor Safeguards
ADS	-	Automatic Depressurization System
AISC	-	American Institute of Steel Construction
AISI	-	American Iron and Steel Institute
ALARA	-	As-Low-As-Reasonably Achievable
ALWR	-	Advanced Light Water Reactor
AMCA	-	Air Movement and Control Association
ANS	-	American Nuclear Society
ANL	-	Argonne National Laboratory
ANSI	-	American National Standards Institute
API	-	American Petroleum Institute
ARI	-	Air Conditioning and Refrigeration Institute
ASCE	-	American Society of Civil Engineers
ASHRAE	-	American Society of Heating, Refrigeration and Air-Conditioning Engineers
ASME	-	American Society of Mechanical Engineers
ASTM	-	American Society for Testing and Materials
ATWS	-	Anticipated Transient Without Scram
AWS	-	American Welding Society
BEACON	-	Best Estimate Analyzer for Core Operations - Nuclear
BOL	-	Beginning of Life
BOP	-	Balance of Plant
BTP	-	Branch Technical Position
CFR	-	Code of Federal Regulations
CHF	-	Critical Heat Flux
CMAA	-	Crane Manufacturers Association of American
CMT	-	Core Makeup Tank
CRD	-	Control Rod Drive
CRDM	-	Control Rod Drive Mechanism
CVS	-	Chemical and Volume Control System
DAC	-	Design Acceptance Criteria
dc	-	Direct Current
DBA	-	Design Basis Accident
DBE	-	Design Basis Event
DCD	-	Design Control Document
DEH	-	Digital Electrohydraulic
DEMA	-	Diesel Engine Manufacturers Association
DNB	-	Departure from Nucleate Boiling
DNBR	-	Departure from Nucleate Boiling Ratio
DOE	-	Department of Energy
DPU	-	Distributed Processing Unit

Table 1.1-1 (Sheet 2 of 4)

AP1000 DCD ACRONYMS

EFPD	-	Effective Full Power Days
EIS	-	Environmental Impact Statement
EMI	-	Electromagnetic Interference
EOF	-	Emergency Offsite Facility
EPA	-	Environmental Protection Agency
EPRI	-	Electric Power Research Institute
ER	-	Environmental Report
ERF	-	Emergency Response Facility
ESF	-	Engineered Safety Features
ESFAS	-	Engineered Safety Features Actuation System
FID	-	Fixed Incore Detector
FM	-	Factory Mutual Engineering and Research Corporation
FMEA	-	Failure Modes and Effects Analysis
FWPCA	-	Federal Water Pollution Control Act
GDC	-	General Design Criteria
GSI	-	Generic Safety Issues
HEPA	-	High Efficiency Particulate Air
HFE	-	Human Factors Engineering
HVAC	-	Heating, Ventilation and Air Conditioning
I&C	-	Instrumentation and Control
ICEA	-	Insulated Cable Engineers Association
IDCOR	-	Industry Degraded Core Rulemaking
IEEE	-	Institute of Electrical and Electronics Engineers
IES	-	Illumination Engineering Society
ILRT	-	Integrated Leak Rate Test
INEL	-	Idaho National Engineering Laboratory
I/O	-	Input/Output
IRWST	-	In Containment Refueling Water Storage Tank
ISA	-	Instrument Society of America
ISI	-	Inservice Inspection
IST	-	Inservice Testing
ITAAC	-	Inspections, Tests, Analyses and Acceptance Criteria
LBB	-	Leak-Before-Break
LOCA	-	Loss of Coolant Accident
LOF	-	Loss-of-Flow with Failure to Scram
LOFT	-	Loss of Flow Test
LOOP	-	Loss of Offsite Power
LOSP	-	Loss of System Pressure with Degraded ECCS Operation
LPZ	-	Low Population Zone
LWR	-	Light Water Reactor
MAAP	-	Modular Accident Analysis Programs
MCC	-	Motor Control Center
MCR	-	Main Control Room

Table 1.1-1 (Sheet 3 of 4)

AP1000 DCD ACRONYMS

MCRHS	-	Main Control Room Habitability System
MFCV	-	Main Feedwater Control Valve
MFIV	-	Main Feedwater Isolation Valve
M-MIS	-	Man-Machine Interface System
MOV	-	Motor-operated Valves
MPC	-	Maximum Permissible Concentration
MSIV	-	Main Steam Isolation Valve
MSLB	-	Main Steam Line Break
MTBE(F)	-	Mean Time Between Event (Failure)
MW	-	Megawatt
MWe	-	Megawatt, electric
MWt	-	Megawatt, thermal
NAE	-	National Academy of Engineering
NAS	-	National Academy of Sciences
NBS	-	National Bureau of Standards
NEC	-	National Electrical Code
NEI	-	Nuclear Energy Institute
NEMA	-	National Electrical Manufacturers Association
NFPA	-	National Fire Protection Association
NPSH	-	Net Positive Suction Head
NRC	-	Nuclear Regulatory Commission
NSSS	-	Nuclear Steam Supply System
NUMARC	-	Nuclear Management and Resources Council (Superceded by NEI)
NUREG	-	Report designator for NRC reports
ORE	-	Occupation Radiation Exposure
PCS	-	Passive Containment Cooling System
P&ID	-	Piping and Instrumentation Diagram
PRA	-	Probabilistic Risk Assessment
PRHR	-	Passive Residual Heat Removal
PRHR HX	-	Passive Residual Heat Removal Heat Exchanger
PWR	-	Pressurized Water Reactor
PXS	-	Passive Core Cooling System
QA	-	Quality Assurance
RAM	-	Reliability, Availability, Maintainability
RAP	-	Reliability Assurance Program
RCS	-	Reactor Coolant System
RCDT	-	Reactor Coolant Drain Tank
RFI	-	Radio Frequency Interference
R.G.	-	Regulatory Guide
RNS	-	Normal Residual Heat Removal
RSW	-	Remote Shutdown Workstation

Table 1.1-1 (Sheet 4 of 4)

AP1000 DCD ACRONYMS

RV	-	Reactor Vessel
SECY	-	Secretary of the Commission Letter
SER	-	Safety Evaluation Report
SMACNA	-	Sheet Metal and Air Conditioning Contractors National Association
SRP	-	Standard Review Plan
SSAR	-	Standard Safety Analysis Report
SSD	-	System Specification Document
SSI	-	Soil Structure Interaction
SSE	-	Safe Shutdown Earthquake
SUFCV	-	Startup Feedwater Control Valve
SUFIV	-	Startup Feedwater Isolation Valve
TID	-	Total Integrated Dose
TMI	-	Three Mile Island
TSC	-	Technical Support Center
UBC	-	Uniform Building Code
UL	-	Underwriters Laboratories
UPS	-	Uninterruptable Power Supply
URD	-	Utility Requirements Document
USI	-	Unresolved Safety Issue
USPHS	-	United States Public Health Service
WCAP	-	Westinghouse report designator, originally Westinghouse Commercial Atomic Power

1.2 General Plant Description

This section includes a general discussion of the objectives, design criteria, operating characteristics and safety considerations for the AP1000 and provides a general description of the plant site, the site criteria, the general plant arrangement, the plant arrangement criteria and key features of each of the individual buildings that are collectively defined as the power generation complex.

Design Certification is sought for the power generation complex, excluding those elements and features considered site-specific. The AP1000 design extends beyond those structures, systems, and equipment which are safety-related. All safety-related structures, systems, and components are located on the nuclear island and are to be included in the design certification. To provide a better understanding of the safety-related features of the AP1000, nonsafety-related features are also described in this DCD. In addition, some plant design features which are outside the boundary of the AP1000, and considered to be site-specific, are described for completeness and to provide a basis for quantification of the required interfaces, as required by 10 CFR 52.47 (a)(1)(ix). The site-specific structures located off the nuclear island are neither safety-related nor seismic Category I. A more complete description of interfaces for the standard design is contained in Section 1.8.

1.2.1 Design Criteria, Operating Characteristics, and Safety Considerations

This section provides an overview of the AP1000 design objectives, design criteria, operating characteristics and safety considerations.

1.2.1.1 Overall Plant

The primary objective of the AP1000 design is to meet applicable safety requirements and goals defined for advanced light water pressurized water reactors with passive safety features. Since the AP600 has already received a Design Certification, it is also a design objective for AP1000 to be as similar as possible to the AP600.

Westinghouse was a principal participant in the development of the EPRI sponsored Utility Requirements Document (URD) and continues to be involved with EPRI on changes to that document. Therefore, an objective of the AP1000 design is to remain as consistent as possible with the EPRI URD. Additional design objectives for the AP1000 are to provide a greatly simplified plant with respect to design, licensing, construction, operation, inspection and maintenance. Specific design objectives follow.

1.2.1.1.1 Power Capability Objectives

- The plant's net electrical power to the grid is at least 1000 MWe with a nuclear steam supply system power rating (core plus reactor coolant pump heat) of about 3415 MWt.

- The plant is designed for rated performance with up to 10 percent of the steam generator tubes plugged and with a maximum hot leg temperature of 610°F.

- The plant is designed to accept a step load increase or decrease of 10 percent between 25 and 100 percent power without reactor trip or steam dump system actuation provided the rated power level is not exceeded.

- The plant is designed to accept a 100 percent load rejection from full power to house loads without reactor trip or operation of the pressurizer or steam generator safety valves. The design provides for a turbine capable of continued stable operation at house loads.

- The plant is designed to accept ramp load changes of 5 percent per minute while operating in the range of 25 to 100 percent of full power without reactor trip or steam dump actuation subject to core power distribution limits and provided the rated power level is not exceeded.

- The plant is designed to permit a design basis daily load follow cycle for at least 90 percent of the fuel cycle length. The design basis daily load follow cycle is defined as the daily (24 hour period) cycle of operation at 100 percent power, followed by a 2-hour linear ramp to 50 percent power, operation at 50 percent power and a 2-hour linear ramp back to 100 percent power. The duration of time at 50 percent power can vary between 2 and 10 hours. This load follow capability is achievable during 90 percent of each fuel cycle.

- During load follow the plant is designed to routinely make load changes of ≤ 10 percent at ± 2 percent per minute between 50 and 100 percent power without exceeding the core power distribution limits for the purpose of responding to grid frequency changes. No change to the reactor coolant boron concentration is required during these load follow maneuvers.

1.2.1.1.2 Reliability and Availability Objectives

- The overall plant availability goal is greater than 90 percent considering all forced and planned outages.

- The rate of unplanned reactor trips goal is less than one per year.

- The plant is designed with significantly fewer components and significantly fewer safety-related components than a current pressurized water reactor of a comparable size.

- The plant design objective is 60 years without the planned replacement of the reactor vessel which itself has a 60 year design objective based on conservative assumptions. The design provides for the replaceability of other major components, including the steam generators.

- The design of the major components required for power generation such as the steam generators, reactor coolant pumps, fuel, internals, turbine and generator is based on equipment that has successfully operated in power plants. Modifications to these proven designs were based on similar equipment that had successful operating experience in similar or more severe conditions.

1.2.1.1.3 Safety Design Criteria

- The plant design conforms to applicable regulations as discussed in Sections 1.9 and 3.1.
- The plant is designed to be fabricated, erected, and operated in such a manner that the release of radioactive materials to the environment does not exceed the limits and guideline values of applicable government regulations pertaining to the release of radioactive materials for normal operations and for design basis transients and accidents.
- Gaseous and liquid waste disposal facilities are designed so that the discharge of radioactive effluents can be made in accordance with applicable regulations.
- The design provides means by which plant operators are alerted when limits on the release of radioactive effluent are approached.
- The reactor core is designed so its nuclear characteristics do not contribute to a divergent power transient.
- The reactor is designed so that there is no tendency for divergent oscillation of any operating characteristic, considering the interaction of the reactor with other appropriate plant systems.
- Sufficient indications are provided to allow determination that the reactor is operating within the envelope of conditions considered by plant safety analysis.
- Essential safety actions are provided by equipment of sufficient redundancy and independence so that no single failure of active components can prevent the required actions.
- Provisions are made for control of active components of nuclear safety systems and engineered safety features from the control room.
- Those portions of the nuclear steam supply system that form part of the reactor coolant pressure boundary are designed to retain integrity as a radioactive material containment barrier following design basis operational transients and accidents.
- Nuclear safety systems and engineered safety features functions are designed so that no damage to the reactor coolant pressure boundary results from internal pressures caused by design basis operational transients and accidents.
- Nuclear safety systems and engineered safety features are designed to permit demonstrations of their functional performance requirements.
- The design of nuclear safety systems and engineered safety features includes allowances for natural environmental disturbances such as earthquakes, floods, and storms at the station site.
- Standby electrical power sources have sufficient capacity to power the nuclear safety systems and engineered safety features requiring electrical power. Safety-related electrical power requirements needed during a loss of offsite power are supplied via Class 1E dc power.

- Standby electrical power sources are provided to allow prompt reactor shutdown and removal of decay heat under circumstances where normal auxiliary power is not available.

- A containment is provided which completely encloses the reactor system.

- The containment is designed to allow periodic integrity and leak tightness testing.

- The containment, in conjunction with other engineered safety features, limits the release of radioactivity from inside the containment, in the event of a design basis accident. This has the effect of limiting radiological consequences of a design basis accident to within an appropriate fraction of regulatory guidelines.

- Piping that penetrates the containment and could serve as a path for the uncontrolled release of radioactive material to the environs is automatically isolated whenever such uncontrolled radioactive material release is threatened. Such isolation is effected in time to limit radiological effects to less than the specified acceptable limits.

- Provisions are made for passively removing energy from the containment to maintain the integrity of the containment system following accidents that release energy to the containment.

- Passive core cooling systems are provided to limit fuel cladding temperature to less than the limits established by 10 CFR 50.46 in the event of a loss-of-coolant accident.

- The passive core cooling system provides for core cooling over the complete range of postulated break sizes in the reactor coolant pressure boundary.

- Actuation of the passive core cooling system occurs automatically when required, regardless of the availability of offsite power supplies and the normal generating system.

- The control room is shielded against radiation so that continued occupancy under accident conditions is possible.

- In the event that the control room becomes uninhabitable, it is possible to bring the reactor from power range operation to safe shutdown conditions by utilizing the remote shutdown workstation located outside the control room.

- Backup reactor shutdown capability is provided independent of normal reactivity control provisions. This backup system has the capability to shutdown the reactor from any normal operating conditions and subsequently to maintain the shutdown condition.

- The fuel handling and storage facility is designed to prevent inadvertent criticality and to maintain shielding and cooling of spent fuel.

1.2.1.1.4 Site Objectives

- The plant is designed for location at a site with the parameters set forth in Chapter 2, Site Characteristics.

1.2.1.1.5 Other Objectives

- The radiation exposure goal for plant personnel resulting from normal operation, inspection and maintenance is less than 100 man-Rem/year. Radiation shielding is provided and access control patterns are established to allow a properly trained operating staff to control radiation doses within the limits of applicable regulations in any mode of normal plant operations.

- The total low level radioactive waste volume goal is less than 1,970 cubic feet per year after de-watering. This waste includes items such as spent resins, spent filter elements, tank sludge, chemical wastes, and clothing. Spent condensate polishing resins are not included. The total wet radioactive waste volume produced from spent resin and filter elements, tank sludge and chemical waste is designed not to exceed 550 cubic feet per year (de-watered).

1.2.1.2 Reactor Coolant System Design

The AP1000 reactor coolant system (Figure 1.2-1) is designed to remove or to enable removal of heat from the reactor during all modes of operation, including shutdown and accident conditions.

The system consists of two heat transfer circuits, each with a steam generator, two reactor coolant pumps, a single hot leg and two cold legs, for circulating reactor coolant. In addition the system includes a pressurizer, interconnecting piping, valves and instrumentation necessary for operational control and safeguards actuation. All system equipment is located in the reactor containment.

During operation, the reactor coolant pumps circulate pressurized water through the reactor vessel and the steam generators. The water, which serves as coolant, moderator and solvent for boric acid (chemical shim control), is heated as it passes through the core to the steam generators where the heat is transferred to the steam system. The water is then is returned to the reactor (core) by the pumps to repeat the process.

The reactor coolant system pressure is controlled by operation of the pressurizer, where water and steam are maintained in equilibrium by the activation of electrical heaters and/or a water spray. Steam is formed by the heaters or condensed by the water spray to control pressure variations due to expansion and contraction of the reactor coolant.

Overpressure protection for the reactor coolant system is provided by the spring loaded safety valves installed on the pressurizer. These valves discharge to the containment atmosphere. The valves for the first three stages of automatic depressurization are also mounted on the pressurizer. These valves discharge steam through spargers to the in-containment refueling water storage tank. The discharged steam is condensed and cooled by mixing with water in the tank.

The reactor coolant system is also served by a number of auxiliary systems, including the chemical and volume control system, the passive core cooling system, the spent fuel pit cooling system, the

steam generator system, the primary sampling system, the liquid radwaste system and the component cooling water system.

1.2.1.2.1 Reactor Design

- The core is designed for an 18-month fuel cycle.
- There are no reactor vessel penetrations below the top of the core.
- The core is designed for a moderator temperature coefficient that is non-positive over the entire fuel cycle at any power level with the reactor coolant at the normal operating temperature.
- A core design is maintained for projected fuel cycles.
- The core design provides adequate margin so that departure from nucleate boiling will not occur with a 95 percent probability and 95 percent confidence basis for all Condition I and II events.
- The core is located low in the vessel to minimize core temperature during loss-of-coolant accidents.
- The vessel and internals are designed so coolant at approximately the average of T_{cold} and T_{hot} is maintained in the head and control rod drive mechanism regions.
- The lower internals are designed to prevent flow jetting into the core.
- Bottom mounted incore instrumentation is not used. No vessel penetrations exist below the top of the core.
- An integrated head package which contains the control rod drive mechanisms, integrated head cooling fans, instrument columns, insulation, seismic support and package lift rig is employed.
- A permanent welded seal ring is used to provide the seal between the vessel flange and the refueling cavity floor.

1.2.1.2.2 Steam Generator Design

- The Model Delta 125 steam generator of proven design is employed. The steam generator employs thermally treated nickel-chromium-iron Alloy 690 tubes and a steam separator area sludge trap with clean out provisions.
- The channel head is designed for the direct attachment of two reactor coolant pumps.
- The channel head is designed for both manual and robotic accessibility for inspection, plugging, sleeving and nozzle dam placement operations.

1.2.1.2.3 Reactor Coolant Pump Design

- Hermetically sealed canned pumps of proven design are employed.
- Two reactor coolant pumps are attached directly to each steam generator channel head with the motor located below the channel head to simplify the loop piping and eliminate fuel uncovery during small loss-of-coolant accidents.
- Each reactor coolant pump includes sufficient internal rotating inertia to provide a flow coastdown to avoid departure from nucleate boiling following a loss of reactor coolant flow accident.
- Each reactor coolant pump impeller and diffuser vanes are ground and polished to minimize radioactive crud deposition and to maximize pump efficiency.
- The reactor coolant pump motors are designed with appropriate lifting and handling attachments (lugs and trunnions) to facilitate maintenance.
- The reactor coolant pumps are designed such that they are not damaged due to a loss of all cooling water until a safety-related pump trip occurs on high bearing water temperature. This automatic protection is provided to protect the reactor coolant pumps from an extended loss of coolant water.

1.2.1.2.4 Pressurizer and Loop Arrangement

- The piping layout is designed for adequate thermal expansion flexibility assuming a fixed vessel and a free floating steam generator/reactor coolant pump support system.
- The reactor coolant loop and surge line piping are designed to leak-before-break criteria.
- The pressurizer is designed such that, with design spray flow rates, the power-operated relief valve function is not required nor provided.

1.2.1.3 Steam and Power Conversion System Design

1.2.1.3.1 Turbine Design

- The turbine is a power conversion system designed to change the thermal energy of the steam flowing through the turbine into rotational mechanical work which rotates a generator to provide electrical power. It consists of a double flow high pressure cylinder (high pressure turbine) and three double flow low pressure cylinders (low pressure turbines) which exhaust to the condenser. It is a six flow tandem compound, 1800 rpm machine. The turbine system includes stop, control and intercept valves directly attached to the turbine and in the steam flow path, crossover and crossunder piping between the turbine cylinders and the moisture separator reheater.

- The high pressure turbine has a connection for one stage of feedwater heating. The high pressure turbine exhaust steam provides steam for one stage of feedwater heating in the deaerator. The low pressure turbines have extraction connections for four stages of feedwater heating.

- The moisture separator reheater is an integral component of the turbine system which extracts moisture from the steam and reheats the steam to improve the turbine system performance. There are two moisture separator reheaters located between the high pressure turbine exhaust and the low pressure turbine inlet. The reheater has a single stage of reheat.

- The turbine orientation minimizes potential interaction between turbine missiles and safety-related structures and components.

1.2.1.3.2 Main Steam System Design

- The main steam system is designed to supply steam from the steam generators to the high pressure turbine over a range of flows and pressures for the entire plant operating range, i.e., from system warmup to valves-wide-open turbine conditions.

- The main steam system is also designed to dissipate heat generated by the nuclear steam supply system to the condenser through steam dump valves or to the atmosphere through power-operated atmospheric relief valves or spring-loaded main steam safety valves when either the turbine-generator or the condenser is not available.

- Six steam generator safety valves are utilized per steam header. There are two steam headers.

1.2.1.3.3 Main Feedwater and Condensate System Design

- The main feedwater system is designed to supply the steam generators with adequate feedwater during all modes of plant operation including transient conditions. The condensate system is designed to condense and collect steam from the low-pressure turbines and turbine steam bypass systems and then, transfer this condensate from the main condenser to the deaerator.

- The main feedwater and condensate systems are designed for increased availability and improved dissolved oxygen control.

- A deaerating heater is employed.

1.2.1.4 Auxiliary Fluid Systems Design

1.2.1.4.1 Engineered Safeguards Systems Design

- The safety systems are designed to mitigate design basis accidents with a single failure, as defined in Chapter 15.

- The safety systems are designed to maximize the use of natural driving forces such as pressurized nitrogen, gravity flow and natural circulation flow. They do not use active components such as pumps, fans or diesel generators. A minimum number of valves are used for the purpose of initially aligning the safety systems.

- The safety systems are designed to function without safety-related support systems such as alternating current, component cooling water, service water, heating, ventilation and air conditioning.

- The number and complexity of operator actions required to control the safety systems are minimized. In meeting this objective, the approach was to eliminate the required action and not to automate them.

- An automatic reactor coolant system depressurization feature is included in the design and meets the following criteria:

  – The reliability (redundancy and diversity) of the automatic depressurization system valves and controls satisfies single failure criteria as well as the failure tolerance required by the low core melt frequency goals.

  – The design provides for both real demands (such as reactor coolant system leaks and failure of the chemical and volume control system makeup pumps) and spurious instrumentation signals. The probability of significant flooding of the containment due to the use of the automatic depressurization system is less than once in 600 years.

- The design is such that, for small break loss-of-coolant accidents up to 8 inches in diameter, the core remains covered.

- The passive safety-related systems can operate for at least 1 hour following anticipated transients without release of contaminants that require significant plant cleanup. The automatic depressurization system is designed not to activate for anticipated transients.

- The passive safety-related systems are designed to cool the reactor coolant system from normal operating temperatures to safe shutdown conditions.

- The passive containment cooling system maintains the containment pressure and temperature within the appropriate design limits for both design basis and severe accident scenarios.

1.2.1.4.2 Nonsafety-Related Systems Designs

- The nonsafety-related systems designs are simplified; the number of systems and components and the complexity of operation and maintenance are reduced from current operating plants.

- The nonsafety-related systems are not relied upon to provide safety functions required to mitigate design basis accidents.

- Nonsafety-related systems that are required for normal plant operation provide high plant availability. These systems have appropriate redundancy, are powered by onsite standby power supplies and have sufficient capacity to prevent automatic passive safety system actuation following anticipated Condition II events.
  - The reactor coolant system makeup capability design is sufficient for reactor coolant leaks up to 3/8 inch.
  - Steam generator feedwater capability from the startup feedwater system is designed to provide sufficient flow for a loss of main feedwater event.
  - The normal containment sump pumps (part of the radioactive waste drain system) are designed to assist in recovery from leakage to the containment sump.
- Boric acid solutions are designed to be stored at concentrations that do not require heat tracing or room temperatures above normal values.

1.2.1.5 Electrical and Control Systems Designs

1.2.1.5.1 Control and Protection Systems Designs

- The design provides that during normal operation, a single failure in the protection and safety monitoring system does not result in a reactor trip or engineered safety features actuation. For the reactor trip function this is true even with a channel under maintenance or test.
- The potential for reactor trip and for safeguards actuation due to failures in the plant control system is reduced relative to current operating plants.
- The number of measured plant variables used for reactor trip and for safeguards actuation is minimized relative to current operating plants.
- The margin between the normal operating conditions and the protection system setpoints is increased relative to current operating plants.
- The potential for interaction between the protection and safety monitoring system and the plant control system is reduced relative to current operating plants by incorporating a signal selector function that selects signals for control and for protection.
- A distributed logic system utilizing multiplexing techniques is used to significantly reduce the amount of wiring required in the plant.

1.2.1.5.2 Alternating Current and Direct Current Power Design

- Safety-related direct current (dc) power is provided to support reactor trip and engineered safeguards actuation. Batteries are sized to provide the necessary dc power and uninterruptible ac power for items such as the protection and safety monitoring system

actuation, the control room functions including habitability, dc-powered valves in the passive safety-related systems and containment isolation.

- All safety-related electrical power is provided from the Class 1E dc power system. No separate safety-related ac power system is required.

1.2.1.5.3 Control Room Design

- A main control room is provided that is able to control the plant during normal and anticipated transients and design basis accidents. The main control room includes indications and controls capable of monitoring and controlling the plant safety systems as well as the nonsafety-related control systems.

- A remote shutdown capability is provided. The remote shutdown workstation contains the safety-related indications and controls that allow an operator to achieve and maintain safe shutdown of the plant following an event when the main control room is unavailable. Additional nonsafety-related indications and controls are provided as described in Chapter 7.

- The remote shutdown workstation contains indications and controls consistent with its intended use; i.e., the remote shutdown workstation is to be used in the unlikely event that the main control room is not available.

- Access to the remote shutdown workstation transfer mechanism is under strict administrative control.

- The main control room is serviced by reliable and redundant nonsafety-related power sources and heating, ventilation and air conditioning systems during normal operation.

- In the unlikely event that the normal power source or the heating, ventilating and air conditioning system becomes unavailable, there are passive systems (batteries, compressed air) to support the main control room for up to 3 days.

- The main control room contains the safety-related instrumentation and controls to allow the operator to achieve and maintain safe shutdown following any design basis accident.

- The safety-related power sources and passive cooling system are designed to provide a habitable environment for the operating staff assuming that no ac power is available. Installed equipment provides for at least 3 days of operation, as stated above. After 3 days, it is possible to continue operation with the control room cooled and ventilated with circulation of outside air.

- A mechanism is provided to allow the operating staff to transfer control from the main control room to the remote shutdown workstation.

- The system prevents spurious signals caused by fire damage from being issued to components once transfer to the remote shutdown workstation has been effected.

- The transfer of the control of components to the remote shutdown workstation is alarmed in the main control room.

- Both the main control room and the remote shutdown workstation are designed in accordance with human factors engineering principles and practices.

- Human factors considerations are utilized so that the indications and controls for the remote shutdown workstation are similar to those provided in the main control room.

- The safety-related instrumentation (equipment racks) is maintained at acceptable ambient conditions for 3 days following a loss of all ac power by using a passive cooling system. After 3 days, it is possible to continue operation with the instrumentation and control rooms cooled by circulation of outside air.

- A technical support center is provided.

1.2.1.6 Plant Arrangement and Construction

1.2.1.6.1 Plant Arrangement

- The plant arrangement is comprised of five principal building structures; the nuclear island, the turbine building, the annex building, the diesel generator building, and the radwaste building (see Figure 1.2-3).

- The nuclear island is structurally designed to meet seismic Category I requirements as defined in Regulatory Guide 1.29. The nuclear island consists of a free-standing steel containment building, a concrete shield building, and an auxiliary building. The foundation for the nuclear island is an integral basemat which supports these buildings.

- The nuclear island structures are designed to withstand the effects of natural phenomena such as hurricanes, floods, tornados, tsunamis, and earthquakes without loss of capability to perform safety functions. Design for natural phenomena is based on the industry standards as described in Chapters 2 and 3.

- The nuclear island is designed to withstand the effects of postulated internal events such as fires and flooding without loss of capability to perform safety functions.

- The turbine building is designed to Uniform Building Code requirements. The turbine building is supported on a single basemat foundation.

- The annex building is designed to seismic Category II requirements and includes functions such as the health physics area, the technical support center, access control, and personnel facilities (shower and locker rooms).

- The diesel generator building houses two diesel generators and their associated heating, ventilation and air conditioning equipment. The building is a nonseismic structure designed for wind and seismic loads in accordance with the Uniform Building Code.

- The radwaste building contains facilities for the handling and storage of plant wastes. It is a nonseismic structure designed for wind and seismic loads in accordance with the Uniform Building Code. The foundation for the building is a reinforced concrete mat on grade.

- Radioactive equipment and piping in all buildings are arranged and shielded to minimize radiation exposure.

- The overall plant arrangement utilizes building configurations and structural designs to minimize the building volumes and quantities of bulk materials (concrete, structural steel, rebar) consistent with safety, operational, maintenance, and structural needs.

- The plant arrangement provides separation between safety-related and nonsafety-related systems to preclude adverse interaction between safety-related and nonsafety-related equipment. Separation between redundant safety-related equipment and systems provides confidence that the safety design functions can be performed. In general this separation is provided by partitioning an area with concrete walls.

- The plant arrangement provides separation for radioactive and non-radioactive equipment and provides separate pathways to these areas for personnel access.

- Pathways through the plant are designed to accommodate equipment maintenance and equipment removal from within the plant. The size of the pathways is dictated by the largest appropriate piece of equipment that may have to be removed or installed after initial installation. Where required, laydown space is provided for disassembling large pieces of equipment to accommodate the removal or installation process.

- Adequate space is provided for equipment maintenance, laydown, removal and inspection. Hatches, monorails, hoists, and removable shield walls are provided to facilitate maintenance.

1.2.2 Site Description

Site Characteristics

The AP1000 is a standard plant that is to be placed on a site with parameters bounded by those used as a basis for design certification as described in Chapter 2, Site Characteristics. The site parameters relate to the seismology, hydrology, meteorology, geology, heat sink and other site-related aspects. The allowable site interface parameters bound a large percentage of potential sites.

The AP1000 is designed on the basis that the equipment, modules, structures, and bulk material can be shipped to the site by commercial rail or truck. This does not preclude the shipment of large equipment or structures by barges should a specific site be accessible by water.

Site Plan

The site plan is defined in the site specific licensing process. A proposed plan has been provided for site interface purposes. Specific details of the site plan will be covered in the site application or in the combined license application.

A typical site plan for the single unit AP1000 reference is shown on Figure 1.2-2. Direction of north, south, east and west used in this description are nominal site description directions and have no relationship to directions on an actual site. With the exception of the parking area, the entire facility is contained within the perimeter fence. The area within the 1400 feet x 775 feet perimeter fence is approximately 25 acres. The gatehouse at the main gate controls ingress and egress to and from the site.

As previously stated in subsection 1.2.1.6.1, the power block complex consists of five principal building structures; the nuclear island, the turbine building, the annex building, the diesel generator building and the radwaste building. Each of these building structures is constructed on an individual basemat. The nuclear island consists of the containment building, the shield building, and the auxiliary building, all of which are constructed on a common basemat.

As shown on the site plan, Figure 1.2-2, these building structures are oriented such that the turbine building is located to the north of the nuclear island, with the other principal buildings adjacent to the nuclear island to meet their functional purpose and to provide access control to vital areas from a central security control point located within the annex building.

The reference plant main cooling tower-circulating water pump complex consists of a natural draft cooling tower, a pump basin, and circulating water pumps. The final configuration of the cooling tower is site-specific.

The circulating water pumps circulate the cooling water from the pump basin to the main condenser and back to the cooling tower through two precast concrete supply and return pipes that are below grade. These two circulating water pipes are shown on Figure 1.2-2 between the main cooling tower and the turbine building.

The transformer area is located immediately adjacent to and north of the turbine building. The unit auxiliary transformers, the reserve auxiliary transformer and the main step-up transformers are located in the transformer area. The main switchyard area is site-specific.

The rail and road accesses to the site are through the east perimeter fence. The rail access to the auxiliary building is primarily for the transportation of new and spent fuel. A rail access to the turbine building is also provided.

During construction, a heavy lift crane is used to place major pieces of equipment such as the turbine-generator, the reactor vessel, the steam generators, containment ring sections, large structural modules and other large or heavy equipment modules.

Figure 1.2-3 provides a functional representation of the principal systems and components that are located in each of the key AP1000 buildings. This figure identifies major systems and components that are contained in these structures.

1.2.3 Plant Arrangement Description

Building Definition

A set of the general arrangement drawings for the AP1000 is provided in Figures 1.2-4 through 1.2-30.

The AP1000 consists of the following five principal structures. Each of these buildings is constructed on an individual basemat:

- Nuclear island
- Turbine building
- Annex building
- Diesel generator building
- Radwaste building

The structures that make up the nuclear island are:

- Containment building
- Shield building
- Auxiliary building

These nuclear island buildings are depicted on the site plan. The safety-related equipment designed to perform accident mitigation functions is located in the nuclear island.

1.2.4 Nuclear Island

1.2.4.1 Containment Building

Building Function

The containment building is the containment vessel and the structures contained within the containment vessel. The containment building is an integral part of the overall containment system with the functions of containing the release of airborne radioactivity following postulated design basis accidents and providing shielding for the reactor core and the reactor coolant system during normal operations.

The containment vessel is an integral part of the passive containment cooling system. The containment vessel and the passive containment cooling system are designed to remove sufficient energy from the containment to prevent the containment from exceeding its design pressure following postulated design basis accidents.

The containment building is designed to house the reactor coolant system and other related systems and provides a high degree of leak tightness.

Civil/Structural Features

The containment building, a seismic Category I structure, is a freestanding cylindrical steel containment vessel with elliptical upper and lower heads. It is surrounded by a seismic Category I reinforced concrete shield building.

Figures 1.2-13 through 1.2-16 provide sectional views through the containment that show the configuration of the containment vessel and the internal structures of the containment.

There are two floor elevations (grade access maintenance floor and operating deck) and four lower equipment compartments within the containment building. Floor gratings are provided for access to equipment at other elevations.

Figures 1.2-7, 1.2-8, 1.2-9, 1.2-15, and 1.2-16 depict the configuration of the refueling water storage tank. This tank is located below the operating deck. The capacity of the refueling water storage tank exceeds the quantity of water required to accomplish safety functions or to fill the refueling cavity during refueling operations. The refueling cavity has two floor elevations. The upper and lower reactor internals storage area is at the lower elevation as is the fuel transfer tube.

Equipment Arrangement

The principal system located within the containment building is the reactor coolant system that consists of two main coolant loops, a reactor vessel, two steam generators, four canned motor reactor coolant pumps, and a pressurizer. Figures 1.2-9, 1.2-14 and 1.2-16 depict the reactor coolant system component locations in the containment.

The main steam and feedwater lines are routed from the steam generators to a horizontal run below the operating deck. The steam and feedwater lines penetrate the north side of the containment vessel and are routed through the main steam isolation valve area in the auxiliary building to the turbine island.

The passive core cooling system is also located in the containment building. The primary components of the passive core cooling system are two core makeup tanks, two accumulators, the refueling water storage tank, the passive residual heat removal heat exchanger, and two spargers. The first three stages of the automatic depressurization valves are located above the pressurizer and consist of a two-tier valve module.

The passive residual heat removal heat exchanger and the spargers are located within the refueling water storage tank (Figures 1.2-7 and 1.2-9). The core makeup tanks are located on floor elevation 107′2″ level (Figures 1.2-7 and 1.2-9).

The chemical and volume control system equipment module is located in the containment below the maintenance floor level. This module represents the high pressure purification loop of the chemical and volume control system (Figure 1.2-14).

The reactor coolant drain tank, the reactor coolant drain tank heat exchanger and the containment sump pumps are located in the compartment adjacent to the reactor vessel cavity. Access to the reactor vessel cavity is via a stairwell that descends from the maintenance floor (Figure 1.2-14).

Two containment recirculation cooling units are located adjacent to the steam generator compartments. Each unit consists of two vane axial fans, cooling coils and the associated exit ducts and inlet plenum. The four recirculation fans are connected to the common exit plenum (ring header). Several vertical ducts branch off from the ring header to provide cooling flow to the lower compartments in the containment while other vertical ducts are directed up to provide cooling flow to the upper regions of the containment vessel.

Equipment and Material Handling

A seismic Category I polar crane is provided in the containment and its bridge is sized for lifting the steam generator during a steam generator removal operation. A temporary construction trolley is required for this operation. The polar crane support is attached to the steel cylindrical shell of the containment as shown in Figures 1.2-14 and 1.2-16.

The layout of the containment is designed to permit the removal of either steam generator through a temporary opening cut through the top of containment, then through the center of the passive containment cooling air diffuser. During a steam generator removal operation, the steam generator is lifted from the steam generator compartment by a temporary construction trolley and then through containment by a large mobile crane.

The polar crane trolley is designed for normal refueling operations such as lifting the integrated head package, the lower internals package and the upper internals package.

An auxiliary hook is provided with the polar crane for easier movement of smaller equipment. The polar crane is used for lifting reactor coolant pump motor/impeller assemblies from the steam generator/loop compartments to the operating deck in the event that the reactor coolant pump motor/impeller assemblies have to be removed from the containment for major maintenance.

A reactor coolant pump maintenance cart is provided for use in either of the two steam generator/loop compartments for removing the reactor coolant pump motor/impeller assemblies from the bottom head of the steam generators. This maintenance cart transports the reactor coolant pump motor/impeller assemblies to a designated area in each of the steam generator/loop compartments where the assemblies are lifted from the compartment to the operating deck by the polar crane. Removable sections of grating at all platform levels in the steam generator/loop compartments permit direct access to the pumps. From the operating deck level, the reactor coolant pump motor/impeller assemblies are removed from the containment via the main equipment hatch into the annex building maintenance area.

A refueling machine is provided to move fuel between the fuel transfer system and the reactor core (Figure 1.2-14). The refueling machine consists of a rectilinear bridge and a trolley crane with a vertical mast extending down into the refueling cavity. The bridge spans the refueling cavity and runs on rails set into the edge of the refueling cavity. The bridge and trolley motions are used to position the vertical mast over a fuel assembly. In addition, the refueling machine is equipped with an auxiliary hoist which provides additional capability for other refueling operations.

A fuel transfer system is provided to transfer nuclear fuel assemblies between the refueling cavity in the containment building and the fuel transfer canal/spent fuel pit located in the fuel handling

area of the auxiliary building. The fuel transfer system also has the capability to transfer control rod clusters.

Building Access and Exit

Access to the containment is provided through a personnel airlock and the main equipment hatch located at the operating deck level and a personnel airlock and a maintenance hatch at the maintenance floor level. Access to the containment can be controlled by the health physics office in the annex building.

In the event that large numbers of temporary personnel require access to the containment during a major outage, temporary personnel facilities can be provided immediately adjacent to the health physics area in the annex building.

1.2.4.2 Shield Building

Building Function

The shield building is the structure that surrounds the containment vessel. During normal operations, a primary function of the shield building is to provide shielding for the containment vessel and the radioactive systems and components located in the containment building. The shield building, in conjunction with the internal structures of the containment building, provides the required shielding for the reactor coolant system and the other radioactive systems and components housed in the containment.

Another function of the shield building is to protect the containment building from external events. The shield building protects the containment vessel and the reactor coolant system from the effects of tornadoes and tornado produced missiles.

During accident conditions, the shield building provides the required shielding for radioactive airborne materials that may be dispersed in the containment as well as radioactive particles in the water distributed throughout the containment.

The shield building is an integral part of the passive containment cooling system.

Civil/Structural Features

The shield building is a seismic Category I reinforced concrete structure. It shares a common basemat with the containment building and the auxiliary building.

Figures 1.2-13 through 1.2-16 provide sectional views of the shield building which show the basic configuration of the shield building and the annulus area between the containment vessel and the shield building.

The following items represent the significant features of the shield building and the annulus area:

- Shield building cylindrical structure
- Shield building roof structure

- Lower annulus area
- Middle annulus area
- Upper annulus area
- Passive containment cooling system air inlet
- Passive containment cooling system air inlet plenum
- Passive containment cooling system water storage tank
- Passive containment cooling system air diffuser
- Passive containment cooling system air baffle

The cylindrical section of the shield building serves as shielding and a missile barrier and is a key component of the passive containment cooling system. It structurally supports the roof and is a major structural member for the entire nuclear island. Floor slabs and structural walls of the auxiliary building are structurally connected to the cylindrical section of the shield building.

A watertight seal is provided between the upper and middle annulus areas to provide an environmental barrier. The middle annulus area contains the majority of containment penetrations and radioactive piping. This environmental barrier is provided to protect against the following:

- In the event of an accident or spurious actuation, the passive containment cooling system drains the system water storage tank. The water, which runs down the outside of the containment vessel, is prevented from draining into the middle annulus area by the watertight seal. Drains are provided to direct the passive containment cooling system runoff water out of the shield building.

- The passive containment cooling system is designed to perform with the upper annulus permanently open to the environment to permit sufficient air flow through the shield building in the event of an accident. The watertight seal protects the middle annulus area from ambient environmental conditions.

The shield building roof is a reinforced concrete conical shell supporting the passive containment cooling system water storage tank and air diffuser. Air intakes are located at the top of the cylindrical portion of the shield building. The conical roof supports the passive containment cooling system water storage tank which is constructed with a stainless steel liner attached to reinforced concrete walls. The air diffuser in the center of the roof discharges containment cooling air directly upwards.

The passive containment cooling system air baffle is located in the upper annulus area. It is attached to the cylindrical section of the containment vessel. The function of the passive containment cooling system air baffle is to provide a pathway for natural circulation of cooling air in the event that a design basis accident results in a large release of energy into the containment. In this event the outer surface of the containment vessel transfers heat to the air between the baffle and the containment shell. This heated and thus, lower density air flows up through the air baffle to the air diffuser and cooler and higher density air is drawn into the shield building through the air inlets at the top cylindrical portion of the shield building.

Equipment and Material Handling

A monorail is provided in the upper annulus area of the shield building to facilitate the initial installation of the passive containment cooling system air baffle panels and to permit the removal of these air baffle panels when an inspection or repainting of the containment vessel is required.

Two personnel workstation platforms are provided for transporting staff and equipment from the operating deck floor level of the upper annulus area to the top of the shield building. The work station platforms are powered from their respective monorail sections and are able to be positioned at any circumferential position or height beneath the monorail sections. Figures 1.2-14 and 1.2-16 depict the monorail system and the personnel work station platforms.

1.2.4.3 Auxiliary Building

Building Function

The primary function of the auxiliary building is to provide protection and separation for the seismic Category I mechanical and electrical equipment located outside the containment building.

The auxiliary building provides protection for the safety-related equipment against the consequences of either a postulated internal or external event. The auxiliary building also provides shielding for the radioactive equipment and piping that is housed within the building.

The most significant equipment, systems, and functions contained within the auxiliary building are the following:

- Main control room
- Class 1E instrumentation and control systems
- Class 1E electrical system
- Fuel handling area
- Mechanical equipment areas
- Containment penetration areas
- Main steam and feedwater isolation valve compartment

Main control room: The main control room provides the human system interfaces required to operate the plant safely under normal conditions and to maintain it in a safe condition under accident conditions. The main control room includes the main control area, the operations staff area, the switching and tagging room and offices for the shift supervisor and administrative support personnel.

Instrumentation and control systems: The protection and safety monitoring system and the plant control system provide monitoring and control of the plant during startup, ascent to power, powered operation, and shutdown. The instrumentation and control systems include the protection and safety monitoring system, the plant control system, and the data display and processing system.

Class 1E electrical system: The Class 1E system provides 125 volts dc power for safety-related and vital control instrumentation loads including monitoring and control room emergency lighting. It is required for safe shutdown of the plant during a loss of ac power and during a design basis accident with or without concurrent loss of offsite power.

Fuel handling area: The primary function of the fuel handling area is to provide for the handling and storage of new and spent fuel. The fuel handling area in conjunction with the annex building provides the means for receiving, inspecting and storing the new fuel assemblies. It also provides for safe storage of spent fuel as described in DCD Section 9.1, Fuel Storage and Handling.

The fuel handling area provides for transferring new fuel assemblies from the new fuel storage area to the containment building and for transferring spent fuel assemblies from the containment building to the spent fuel storage pit within the auxiliary building.

The fuel handling area provides the means for removing the spent fuel assemblies from the spent fuel storage pit and loading the assemblies into a shipping cask for transfer from the facility.

The fuel handling area is protected from external events such as tornadoes and tornado produced missiles. Protection is provided for the spent fuel assemblies, the new fuel assemblies and the associated radioactive systems from external events.

The fuel handling area is constructed so that the release of airborne radiation following any postulated design basis accident that could result in damage to the fuel assemblies or associated radioactive systems does not result in unacceptable site boundary radiation levels.

Mechanical equipment areas: The mechanical equipment located in radiological control areas of the auxiliary building are the normal residual heat removal pumps and heat exchangers, the spent fuel cooling system pumps and heat exchangers, the solid, liquid, and gaseous radwaste pumps, tanks, demineralizers and filters, the chemical and volume control pumps, and the heating, ventilating and air conditioning exhaust fans.

The mechanical equipment located in the clean areas of the auxiliary building are the heating, ventilating and air conditioning air handling units, associated equipment that service the main control room, instrumentation and control cabinet rooms, the battery rooms, the passive containment cooling system recirculation pumps and heating unit and the equipment associated with the air cooled chillers that are an integral part of the chilled water system.

Containment penetration areas: The auxiliary building contains all of the containment penetration areas for mechanical, electrical, and instrumentation and control penetrations. The auxiliary building provides separation of the radioactive piping penetration areas from the non-radioactive penetration areas and separation of the electrical and instrumentation and control penetration areas from the mechanical penetration areas. Also provided is separation of redundant divisions of instrumentation and control and electrical equipment.

Main steam and feedwater isolation valve compartment: The main steam and feedwater isolation valve compartment is contained within the auxiliary building. The auxiliary building provides an adequate venting area for the main steam and feedwater isolation valve compartment in the event of a postulated leak in either a main steam line or feedwater line.

Civil/Structural Features

The auxiliary building is a seismic Category I reinforced concrete structure. It shares a common basemat with the containment building and the shield building.

The auxiliary building wraps around approximately 70 percent of the circumference of the shield building. Floor slabs and the structural walls of the auxiliary building are structurally connected to the cylindrical section of the shield building.

Equipment and Material Handling

A cask handling crane is located in the fuel handling area of the auxiliary building. The cask handling crane is designed to transport the spent fuel cask between the rail car, the cask loading pit, and the cask washdown pit. The crane rail length and rail stop limits the crane travel and thus precludes the movement of this crane in the near vicinity of the spent fuel pit. A jib crane is provided to transfer new fuel from the new fuel racks to the new fuel elevator. A bridge crane is provided in the rail car bay for handling the spent resin waste container fill station cover, the spent resin waste container, and the high activity filter transfer casks.

The major components of the fuel transfer system are located in the fuel transfer canal. The fuel transfer system is designed to transfer fuel assemblies between the fuel transfer canal located in the fuel handling area and the refueling cavity located in the containment building. The fuel transfer system consists of a transfer car/fuel container, a drive car, a traverse drive mechanism, an upending mechanism, the transfer tube, a quick opening hatch on the containment side of the transfer tube and a valve on the fuel handling area side of the transfer tube.

A spent fuel handling machine is provided to move the spent fuel assemblies between the fuel transfer canal, the spent fuel pool and the cask loading pit. The spent fuel pool handling machine consists of a rectilinear bridge and a trolley crane with a vertical mast extending down into the spent fuel pool.

The high bay area is designed for a rail car to enter the building through a slide-up door. When used to transport a spent fuel cask to the fuel handling area, the rail car is positioned in the high bay area and the cask lifting rig is attached to the cask handling crane. When the cask is in the vertical position, it is disconnected from the trunnion and lifted to the operating deck through the equipment hatch and placed in the cask loading pit.

1.2.5 Annex Building

Building Function

The annex building (Figures 1.2-17 through 1.2-20) provides the main personnel entrance to the power generation complex. It includes accessways for personnel and equipment to the clean areas of the nuclear island in the auxiliary building and to the radiological control area. The building includes the health physics facilities for the control of entry to and exit from the radiological control area as well as personnel support facilities such as locker rooms. The building also contains the non-1E ac and dc electric power systems, the ancillary diesel generators and their fuel

supply, other electrical equipment, the technical support center, and various heating, ventilating and air conditioning systems. No safety-related equipment is located in the annex building.

The annex building includes the health physics facilities and provides personnel and equipment accessways to and from the containment building and the rest of the radiological control area via the auxiliary building. Provided are large, direct accessways to the upper and lower equipment hatches of the containment building for personnel access during outages and for large equipment entry and exit. The building includes a hot machine shop for servicing radiological control area equipment. The hot machine shop includes decontamination facilities including a portable decontamination system that may be used for decontamination operations throughout the nuclear island.

Civil/Structural Features

The annex building is a seismic Category II structure except for that portion of the building between column lines A and D, which is non-seismic. It is designed so that it will not fail in a manner that would damage safety-related structures. No protection against missile penetration is required. However, certain areas of the building, such as the hot machine shop and the technical support center, are provided with shielding for protection against low level radiation from either internal sources or external sources under accident conditions. This is accomplished by either reinforced concrete walls or reinforced masonry walls.

The annex building is a combination of reinforced concrete structure and steel framed structure with insulated metal siding. Floor and roof slabs are reinforced concrete supported by metal decking. Floors are designed to act as diaphragms to transmit horizontal loads to side wall bracing and to concrete shear walls. The building foundation is a reinforced concrete mat.

1.2.6 Diesel Generator Building

Building Function

The diesel generator building (Figure 1.2-21) houses two identical slide along diesel generators separated by a three hour fire wall. These generators provide backup power for plant operation in the event of disruption of normal power sources. No safety-related equipment is located in the diesel generator building.

Civil/Structural Features

The diesel generator building houses the two diesel generators and their associated heating, ventilating and air conditioning equipment, none of which are required for the safe shutdown of the plant. Accordingly, the building is designed as a nonseismic structure subject to seismic and wind loads in accordance with the Uniform Building Code.

The building is a single story steel framed structure with insulated metal siding. The roof is composed of a metal deck supporting a concrete slab and serves as a horizontal diaphragm to transmit lateral loads to sidewall bracing and thereby to the foundation.

The foundation consists of a reinforced concrete mat. The diesel generators are skid-mounted and rest on vibration isolators supported directly from the mat.

1.2.7 Radwaste Building

Building Function

The radwaste building includes facilities for segregated storage of various categories of waste prior to processing, for processing by mobile systems, and for storing processed waste in shipping and disposal containers. No safety-related equipment is located in the radwaste building. Dedicated floor areas and trailer parking space for mobile processing systems is provided for the following:

- Contaminated laundry shipping for offsite processing
- Dry waste processing and packaging
- Hazardous/mixed waste shipping for offsite processing
- Chemical waste treatment
- Empty waste container receiving and storage
- Storage and loading packaged wastes for shipment

The radwaste building also provides for temporary storage of other categories of plant wastes.

Civil/Structural Features

The radwaste building general arrangement is shown on Figure 1.2-22. The radwaste building is a nonseismic structure designed in accordance with the Uniform Building Code. The liquid radwaste processing areas are designed to contain any liquid spills. These provisions include a raised perimeter and floor drains that lead to the liquid radwaste system waste holdup tanks. The foundation for the entire building is a reinforced concrete mat on grade.

1.2.8 Turbine Building

Building Function

The turbine building houses the main turbine, generator, and associated fluid and electrical systems. It provides weather protection for the laydown and maintenance of major turbine/generator components. The turbine building also houses the makeup water purification system. No safety-related equipment is located in the turbine building.

Civil/Structure Features

The turbine building, shown in Figures 1.2-23 through 1.2-30, is a steel column and beam structure. The turbine building ground floor (structural mat) is a reinforced concrete slab. The turbine building is a nonseismic structure designed for wind and seismic loads in accordance with the Uniform Building Code.

The turbine-generator is low-tuned by means of spring supports. The design consists of a reinforced concrete deck mounted on springs. The springs are supported on a structural steel

framework that forms an integral part of the turbine building structural system. Lateral bracing serves to provide lateral support for the building as well as the turbine-generator support. The spring-supported concept isolates dynamically the turbine-generator deck from the remainder of the structure for operating frequencies, thus allowing for an integrated structure below the deck. This includes an integrated reinforced concrete foundation mat that supports both the turbine generator and the building. The condenser is attached rigidly to the low pressure turbine exhaust and is supported on springs. The foundation for the entire building is a reinforced concrete mat.

1.2.9 Combined License Information

This section has no requirement for additional information to be provided in support of the Combined License application.

[Page Intentionally Left Blank]

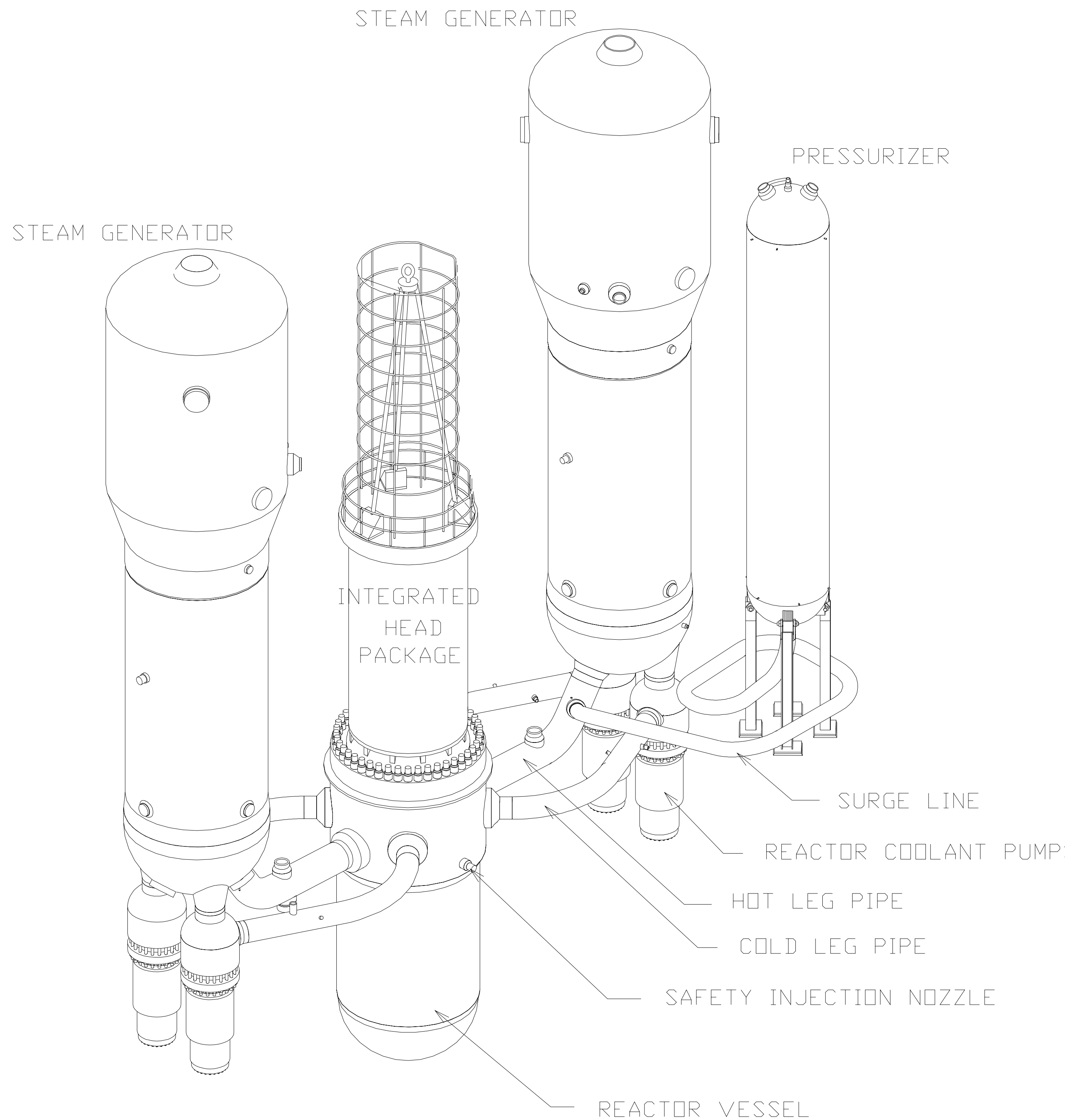


Figure 1.2-1

Reactor Coolant System

Withheld under 10 CFR 2.390.

Figure 1.2-2

Site Plan

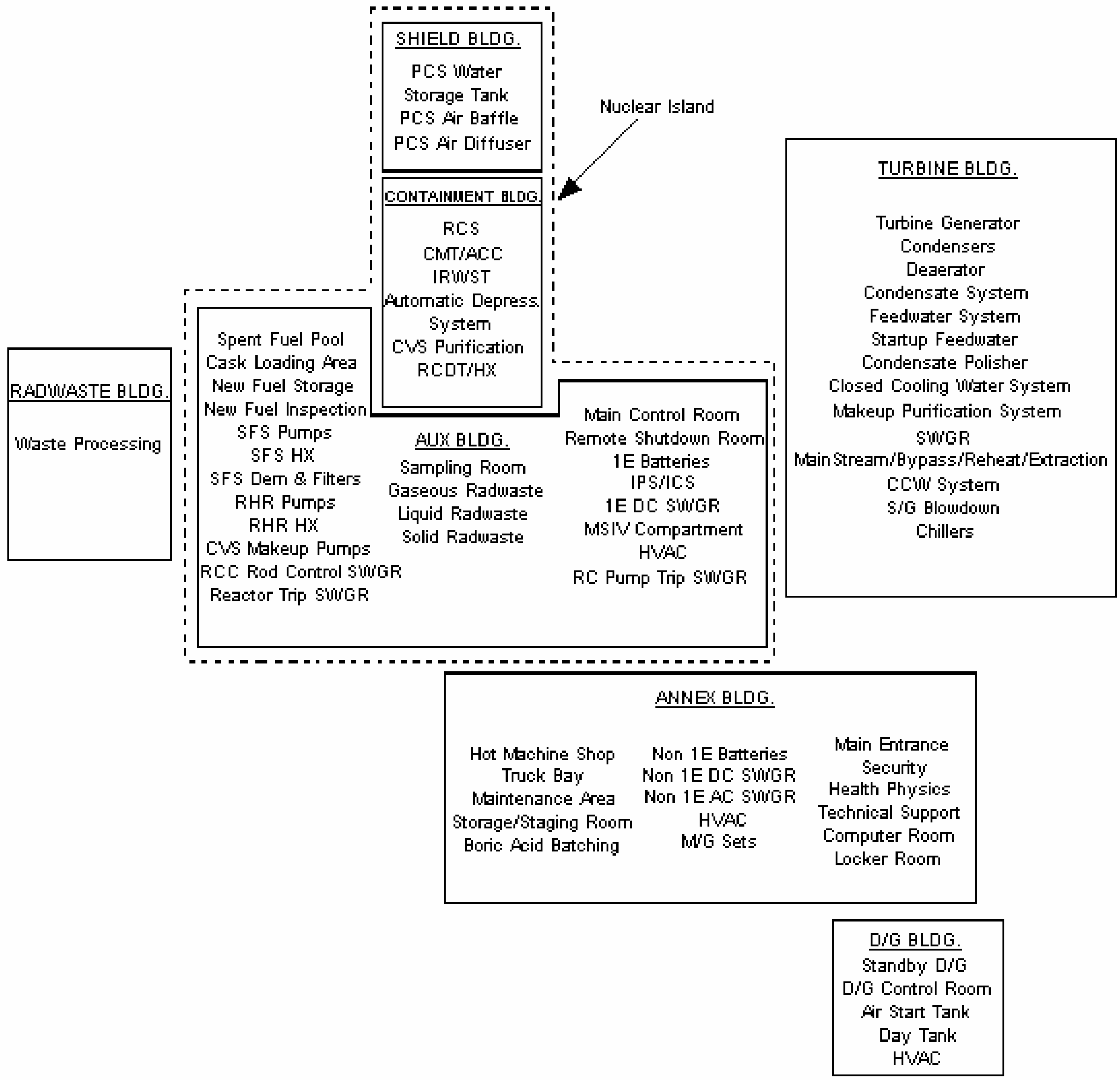


Figure 1.2-3

Functional Allocation of System Components of AP1000 Power Generation Complex

Withheld under 10 CFR 2.390.

Figure 1.2-4

Nuclear Island General Arrangement
Plan at Elevation 66′-6″

Withheld under 10 CFR 2.390.

Figure 1.2-5

Nuclear Island General Arrangement
Plan at Elevation 82′-6″

Withheld under 10 CFR 2.390.

Figure 1.2-6

Nuclear Island General Arrangement
Plan at Elevation 96′-6″

Withheld under 10 CFR 2.390.

Figure 1.2-7

Nuclear Island General Arrangement
Plan at Elevation 107′-2″ & 111′-0″

Withheld under 10 CFR 2.390.

Figure 1.2-8

Nuclear Island General Arrangement
Plan at Elevation 117′-6″ & 130′-0″

Withheld under 10 CFR 2.390.

Figure 1.2-9

Nuclear Island General Arrangement
Plan at Elevation 117′-6″ with Equipment

Withheld under 10 CFR 2.390.

Figure 1.2-10

Nuclear Island General Arrangement
Plan at El. 135′-3″

Withheld under 10 CFR 2.390.

Figure 1.2-11

Nuclear Island General Arrangement
Plan at Elevation 153′-0″ & 160′-6″

Withheld under 10 CFR 2.390.

Figure 1.2-12

Nuclear Island General Arrangement
Plan at Elevation 160′-6″ & 180′-0″

Withheld under 10 CFR 2.390.

Figure 1.2-13

Nuclear Island General Arrangement
Section A-A

Withheld under 10 CFR 2.390.

Figure 1.2-14

**Nuclear Island General Arrangement
Section A-A with Equipment**

Withheld under 10 CFR 2.390.

Figure 1.2-15

Nuclear Island General Arrangement
Section B-B

Withheld under 10 CFR 2.390.

Figure 1.2-16

Nuclear Island General Arrangement
Section B-B with Equipment

Withheld under 10 CFR 2.390.

Figure 1.2-17

Annex Building General Arrangement
Section A-A

Withheld under 10 CFR 2.390.

Figure 1.2-18

Annex Building General Arrangement
Plan at Elevation 100′-0″ & 107′-2″

Withheld under 10 CFR 2.390.

Figure 1.2-19

Annex Building General Arrangement Plan at Elevation 117′-6″ & 126′-3″

Withheld under 10 CFR 2.390.

Figure 1.2-20

Annex Building General Arrangement
Plan at Elevation 135′-3″, 156′-0″ & 158′-0″

Withheld under 10 CFR 2.390.

Figure 1.2-21

Diesel Generator Building General Arrangement Plan at Elevation 100′-0″ & Section A-A

Withheld under 10 CFR 2.390.

Figure 1.2-22

Radwaste Building General Arrangement
Plan at El. 100′-0″

Withheld under 10 CFR 2.390.

Figure 1.2-23

Turbine Building General Arrangement
Plan at Elevation 100′-0″

Withheld under 10 CFR 2.390.

Figure 1.2-24

Turbine Building General Arrangement
Plan at Elevation 117′-6″

Withheld under 10 CFR 2.390.

Figure 1.2-25

Turbine Building General Arrangement Plan at Elevation 135′-3″

Withheld under 10 CFR 2.390.

Figure 1.2-26

Turbine Building General Arrangement
Plan at Elevation 161′-0″

Withheld under 10 CFR 2.390.

Figure 1.2-27

Turbine Building General Arrangement
Plan at Elevation 161′-0″ with Equipment

Withheld under 10 CFR 2.390.

Figure 1.2-28

Turbine Building General Arrangement
Plan at El. 194′-0″ & 224′-0″

Withheld under 10 CFR 2.390.

Figure 1.2-29

Turbine Building General Arrangement
Section A-A

Withheld under 10 CFR 2.390.

Figure 1.2-30

Turbine Building General Arrangement
Section B-B

1.3 Comparisons With Similar Facility Designs

A comparison of the major AP1000 design features and nominal parameters with the certified AP600 and a typical two-loop Westinghouse plant is provided in Table 1.3-1. The values provided for AP1000 are nominal and provided for comparison. Design parameter values for design certification are delineated in the sections referenced. The values provided in Table 1.3-1 for the reference AP600 and two-loop plants are typical. The two-loop plant parameters are represented by Waterford Unit 3.

Table 1.3-1 (Sheet 1 of 6)

AP1000 PLANT COMPARISON WITH SIMILAR FACILITIES

Systems – Components	DCD	AP1000	AP600	Reference 2 Loop
Plant design objective	1.2	60 yrs	60 yrs	40 yrs
NSSS power	4.0	3,415 MWt	1,940 MWt	3,410 MWt
Core power	4.0	3,400 MWt	1,933 MWt	3,390 MWt
Net electrical output	1.2	1,090 MWe	600 MWe	1,075 MWe
Reactor operating pressure	5.1	2,250 psia	2,250 psia	2,250 psia
Hot leg temp	5.1	610°F	600°F	611°F (Cycle 1) 603°F (current)
Steam Generator Design pressure	5.4	1200 psia	1200 psia	1100 psia
Main feedwater temp	10.3	440°F	435°F	445°F
Core	4.0			
Number fuel assem.		157	145	217
Active fuel length		168 in	144 in	150 in
Fuel assembly array		17 x 17	17 x 17	16 x 16
Fuel rod OD		0.374 in	0.374 in	0.382 in
Number control assem.		53	45	83
– Absorber material		Ag-In-Cd	Ag-In-Cd	B_4C/Ag-In-Cd
Number gray rod assem.		16	16	8 (part length)
– Absorber material		SS-304/Ag-In-Cd	SS-304/Ag-In-Cd	Inconel 625/ B_4C
Avg linear power		5.707 kW/ft	4.10 kW/ft	5.34 kW/ft
Heat flux hot channel factor, FQ		2.60	2.60	2.35

Table 1.3-1 (Sheet 2 of 6)

AP1000 PLANT COMPARISON WITH SIMILAR FACILITIES

Systems – Components	DCD	AP1000	AP600	Reference 2 Loop
Reactor Vessel	5.3			
Vessel ID		159 in	157 in	172 in
Construction		forged rings	forged rings	welded plate
Number hot leg nozzles		2	2	2
– ID		31.0 in	31.0 in	42 in
Number cold leg nozzles		4	4	4
– ID		22.0 in	22.0 in	30 in
Number safety injection nozzles		2	2	0
Steam Generators	5.4.2			
Type		Vertical U-tube Recirc. design	Vertical U-tube Recirc. design	Vertical U-tube Recirc. design
Model		Delta-125	Delta-75	–
Number		2	2	2
Heat transfer area/SG		125,000 ft^2	75,180 ft^2	103,574 ft^2
Number tubes/SG		10,000	6,307	9,300
Tube material		I 690 TT	I 690 TT	I 600 TT
Separate startup feedwater nozzle		Yes	Yes	No
Reactor Coolant Pumps	5.4.1			
Type		canned	canned	shaft seal
Number		4	4	4
Rated HP		6,000 hp/pump	≤3,500 hp/pump	9,700 hp/pump
Estimated flow/loop		150,000 gpm	102,000 gpm	198,000 gpm

Table 1.3-1 (Sheet 3 of 6)

AP1000 PLANT COMPARISON WITH SIMILAR FACILITIES

Systems – Components	DCD	AP1000	AP600	Reference 2 Loop
Pressurizer	5.4.5			
Total volume		2,100 ft^3	1,600 ft^3	1,500 ft^3
Volume/MWt		0.618 ft^3/MWt	0.825 ft^3/MWt	0.440 ft^3/MWt
Safety valves #/size		2 – 6"x8"	2 – 6"x6"	3 – 6"
PORV #/size		no	no	no
PRT volume		no	no	2,400 ft^3
Auto depressurization		yes	yes	no
Turbine Island	10.2			
Turbine – # HP cylinder		1	1	1
# LP cylinders		3	2	3
Max blade length		54 in	47 in	40 in
Number reheat stages		2	1	1
Feedwater heating stages				
– # LP stages		4	4	5
– # HP stages		1	2	1
Deaerator		yes	yes	no
Main feedwater pumps		3 motor driven	2 motor driven	2 turbine driven
Condensate pumps		3	3	3
Condenser tube material		Ti	Ti	SS
Condensate polishing		0–33%	33%	0–100%

Table 1.3-1 (Sheet 4 of 6)

AP1000 PLANT COMPARISON WITH SIMILAR FACILITIES

Systems – Components	DCD	AP1000	AP600	Reference 2 Loop
Containment	6.2			
Type		Steel	Steel	Steel
Inside dia.		130 ft	130 ft	140 ft
Volume		2.06 E+06 ft^3	1.76 E+06 ft^3	2.677 E+06 ft^3
Volume/MWt		606 ft^3/MWt	910 ft^3/MWt	785 ft^3/MWt
Post accident cooling		Air and water on outside of steel containment vessel	Air and water on outside of steel containment vessel	Component cooling water cooled fan coolers
Safety Injection	6.3			
Accumulator – #/volume		2/2,000 ft^3	2/2,000 ft^3	4/2,250 ft^3
Core makeup tank – #/volume		2/2,500 ft^3	2/2,000 ft^3	no
High head pumps – #		none	none	3
– runout flow		–	–	380 gpm
– shutoff head		–	–	1,365 psi
Low head pumps – #		none	none	See RHR pumps
Refuel water storage tank – #		1	1	1
– location		in containment	in containment	ex-containment
– volume		590,000 gal	530,000 gal	475,000 gal
Boron inject tank #/vol		no	no	1/630 gal (batching) 2/11,800 gal (makeup)
Normal Residual Heat Removal (NRHR)	5.4.7			
Design pressure		900 psig	900 psig	650 psig
Normal RHR pumps – #/design flow		2/1,000 gpm per pump	2/1,000 gpm per pump	2/4,050 gpm per pump

Table 1.3-1 (Sheet 5 of 6)

AP1000 PLANT COMPARISON WITH SIMILAR FACILITIES

Systems – Components	DCD	AP1000	AP600	Reference 2 Loop
Cooling Water Systems	9.2			
Safety-related		no	no	yes
Component cooling water pumps		2	2	3
Service water pumps		2	2	none
Heat sink		Separate mechanical draft cooling towers	Separate mechanical draft cooling towers	Separate mechanical draft cooling towers
Startup/Auxiliary Feedwater	10.4			
Motor pumps – #/flow per pump/safety-related		2/520 gpm/no	2/380 gpm/no	2/350 gpm/yes 1/900 gpm/no
Turbine pumps – #/flow		none/–	none/–	1/700 gpm
Passive RHR HX – #/heat removal/safety-related		1/60 MW/Yes	1/42 MW/Yes	None/–/–
Chemical and Volume Control	9.3.6			
Purification/Letdown flow				
– normal		100 gpm	100 gpm	38 gpm
– max		100 gpm	100 gpm	126 gpm
Purification location		IRC	IRC	ORC
RCP seal injection/pump		none	none	5 – 8 gpm
Charging pumps		2 @ 100 gpm	2 @ 100 gpm	3 @ 44 gpm
– SI use		no	no	no
– safe shutdown use		no	no	yes
– continuous oper.		no	no	yes
Boron thermal regeneration		no	no	no
Boron recycle evaporator		no	no	no

Table 1.3-1 (Sheet 6 of 6)

AP1000 PLANT COMPARISON WITH SIMILAR FACILITIES

Systems – Components	DCD	AP1000	AP600	Reference 2 Loop
Instrumentation and Control	7.7			
Type I&C system		digital	digital	analog
Type control room		work station	work station	control boards
Electrical				
Diesels – #	8.31	2	2	2
– safety-related		no	no	yes
– capacity		4,000 kW	4,000 kW	4,400 kW
1E batteries – total capacity	8.32	28,000 amp-hr	28,000 amp-hr	3 x 2,320 amp-hr (@ 8 hour rate)

1.4 Identification of Agents and Contractors

1.4.1 Applicant – Program Manager

Westinghouse Electric Company, LLC (Westinghouse), is responsible for the overall design and design certification of the AP1000 nuclear power plant. A significant portion of the AP1000 design is the same as the design of AP600. Westinghouse Electric Company was also responsible for the overall design and design certification of AP600.

Westinghouse has designed, developed, and manufactured nuclear facilities since the 1950s, beginning with the world's first large central station nuclear plant (Shippingport), which produced power from 1957.

Westinghouse has designed and delivered more than 100 commercial nuclear power plants with a combined electrical generating capacity in excess of 90,000 MW. The company's manufacturing facilities include the commercial nuclear fuel fabrication facility at Columbia, South Carolina; and nuclear component manufacturing facilities at Blairsville, Pennsylvania; and Newington, New Hampshire.

Westinghouse has been involved with advanced light water reactor plant design efforts for over fifteen years. Included is the development of the advanced, passive pressurized water reactors known as the AP600 and AP1000.

Westinghouse has substantial, proven experience, knowledge, and capability to design, manufacture and furnish technical assistance for the installation, startup and service of nuclear power plants.

1.4.2 Other Contractors and Participants

Under the direction of Westinghouse, a number of highly qualified organizations provide design and analysis in support of the AP600 and AP1000. Each has a specific responsibility to Westinghouse as defined by various contracts and agreements. Where design features are the same between AP600 and AP1000, the design and analysis performed for AP600 by organizations other than Westinghouse are applied directly to AP1000. The major contributors are identified in this section. They are included here if they have contributed to the base AP600 design or if they have contributed specifically to the AP1000 design.

Throughout the design process, lines of communication have been established among all participants. Design information is generated using common formats, electronic tools and software. Common requirement and compliance documentation has been established and followed. This has allowed design to progress in a complete and consistent manner with interfaces explicitly managed.

1.4.2.1 Bechtel North American Power Corporation

Bechtel North American Power Corporation (Bechtel) is one of the foremost architect-engineering firms in the United States, with the design and construction of 150 nuclear power projects in

25 countries to its credit. In addition to new construction, Bechtel has first-hand experience in operating plant retrofit design and construction, as well as maintenance and management.

1.4.2.2 Southern Electric International

Southern Electric International (SEI) is a wholly owned subsidiary of The Southern Company. The Southern Company is comprised of Southern Company Services, Inc. (an engineering technical services company), six operating utility companies, and Southern Electric International (a commercial engineering consulting services company).

Southern Electric International has benefited from over 99 years of engineering and consulting services experience with the Southern electric utility system. This expertise is derived from experience in designing, constructing, operating, maintaining, and modernizing the 251 generating units of the Southern electric system and those of Southern Electric International's clients. Southern Electric International provides a unique perspective and expertise of an operating electric utility.

1.4.2.3 Burns & Roe Company

Burns & Roe Company is an architect-engineering firm with considerable nuclear expertise. Burns & Roe has provided design, construction management and modernization services to a wide variety of domestic and foreign operating utilities. Burns & Roe contributed to the design and installation of a number of commercial nuclear power plants. Burns & Roe has also been involved with the development of advanced light water reactors since their inception.

1.4.2.4 Washington Group (MK-Ferguson Company)

MK-Ferguson Company is one of the larger construction firms in the world. Their planning and construction management work extends to commercial and industrial projects as well as power generation units. They are a DOE-approved subcontractor on the defense waste processing facility at Savannah River and have worked on such diverse nuclear plant challenges as the replacement of the steam generator at the D.C. Cook Nuclear Plant, decommissioning of the Shippingport Plant and nuclear reactor modifications at Bettis Atomic Power Laboratory.

1.4.2.5 Avondale Industries, Inc.

Avondale Industries, Inc. is the United States pioneer and leader in modular construction. Their modern shipyards prove ideally suited for the modular construction of industrial and commercial facilities. They have the sophisticated infrastructure in engineering, program management, materials and cost control needed to support large, complex projects.

1.4.2.6 Chicago Bridge & Iron Services, Inc.

Chicago Bridge & Iron Services (CBI) is the leading designer and maker of nuclear reactor containment vessels and liners. They have successfully erected 107 containment structures, 70 percent of all containments built in the United States. Chicago Bridge & Iron Services also specializes in operating plant modification and maintenance upgrades; their service expertise

includes planning, development, scheduling and implementation of work procedures, ALARA, and decontamination.

1.4.2.7 Other Participants

Westinghouse has also received support from a variety of engineering and testing firms on a subcontract basis. The organizations providing important design or testing services include: SOPREN/ANSALDO of Italy, University of Western Ontario of Canada, ENEL of Italy, BATAN of Indonesia, ENEA of Italy, BPPT of Indonesia, FIAT of Italy, INITEC of Spain, UNESA of Spain, UTE of Spain, PLN/BPPT of Indonesia, Oregon State University, EdF of France, SNERDI of China, MHI of Japan, UAK of Switzerland, DTN of Spain and Fortum of Finland.

1.4.3 Combined License Information

This section has no requirement for additional information to be provided in support of the combined license application.

1.5 Requirements for Further Technical Information

Introduction

Tests were conducted during the AP600 Conceptual Design Program (1986 through 1989) to provide input for plant design and to demonstrate the feasibility of unique design features. Tests for the AP600 design certification and design program were devised to provide input for the final safety analyses, to verify the safety analysis models (computer codes), and to provide data for final design and verification of plant components. An AP1000 specific Phenomena Identification and Ranking Table (PIRT) and scaling analysis (Reference 25) and a review of safety analysis evaluations of AP1000 (Chapter 15 of this DCD) show that AP600 and AP1000 exhibit a similar range of conditions for the events analyzed. This provides justification that the database of test information generated during the AP600 Conceptual Design Program is sufficient to meet the requirements of 10 CFR Part 52 for AP1000. Table 1.5-1 is a list of the AP600 tests and AP1000 evaluations with references to test and evaluation documentation. Note that Reference 25 reviews each of the AP600 tests described and assesses their applicability to AP1000. The evaluations of Reference 25 show that the AP600 tests are sufficient to support AP1000 safety analysis.

The AP600 tests related to the plant safety functions were selected based on the plant features that are different from current PWRs and where directly applicable experimental data are not available. The tests simulate plant features as required to demonstrate the phenomena being examined. To validate the computer models, these experiments are modeled using the same computer codes used for plant analyses.

Testing of some plant component designs is required to verify their reliability and manufacturability. Other component tests provide data for design optimization. The completed component design tests are described below.

1.5.1 AP600 Safety-Related Tests

The AP600 safety-related experiments are designed to meet several goals:

- Provide input for safety analysis
- Provide data on the passive safeguards systems to validate the safety analysis methods and computer codes
- Assess the design margin in the passive safety system performance

To accomplish these goals, the AP600 test program utilizes the available data from the NRC and industry light water reactor safety research programs as well as specific tests which address the uniqueness of the AP600. The AP600 safety-related test program utilizes component experiments and integral tests to determine the transient behavior of the AP600 safety system components such that computer models can be developed and verified.

The range of plant conditions for design basis accidents and transients, and the new features of the AP600 design were evaluated against current Westinghouse designs and safety-related data available in the literature (NUREG-1230). The results of this assessment were used to determine

the data needs, and to define the experiments to support the AP600 safety analysis. Based upon the experiments performed for AP600 and the AP1000 range of plant conditions for design basis accidents and transients, the tests were shown to be sufficient to support AP1000 safety analysis as well.

1.5.1.1 Large-Break LOCA

For large-break LOCA safety analysis, the relevant new features of the AP600 were the core makeup tanks (CMTs), which drain by gravity, and the use of hermetically sealed, high inertia centrifugal canned-motor reactor coolant pumps (RCPs). Two-phase pump flow data exists for Westinghouse designed pumps and others (NUREG-1230) that can be used to characterize the AP600 pumps. The core makeup tank is unique to the AP600 and AP1000 design. A specific AP600 test was conducted for this component. In addition, a test of passive safety injection system check valve flow vs. ΔP with low differential pressure has been completed. The evaluation of Reference 25 shows that these tests are applicable to AP1000.

Core Makeup Tank Performance Test

The purpose of this experiment is to verify the natural circulation and draining behavior of the core makeup tank over a full range of flowrates, pressures and temperatures, and to provide data to support the design and operation of the tank level indication which acts as a control for the automatic depressurization system (ADS). When actuated, the CMT adds water mass to the reactor coolant system (RCS) by natural circulation when the cold leg contains hot water. The water in the core makeup tank drains by gravity head into the RCS when steam is provided from the cold leg to the top of the core makeup tank. This steam replaces the water drained from the core makeup tank. Some of the steam condenses upon entry into the core makeup tank and can affect the tank draining performance. The objective of the test is to verify that the tank will drain as predicted.

A one-eighth diameter and one-half height scale core makeup tank was constructed and instrumented to obtain the condensation rates within the tank to verify the computer model. The core makeup tank water delivery was examined.

Passive Safety Injection System Check Valve Tests

The AP1000 uses check valves to isolate passive systems from the reactor coolant system. Tests have been performed in the AP600 test program on these check valves to demonstrate their operability.

Tests were conducted to measure check valve pressure drop from very low flow to full flow conditions. Detailed data on initial valve opening, valve disk behavior and flow versus differential pressure were obtained for individual check valves as well as for valves installed in series.

Initial check valve low differential opening tests have determined the characteristic valve flow under the expected gravity drain conditions. A review of existing utility information has been conducted to assess check valve performance under conditions similar to those which would be experienced by the gravity drain check valves.

1.5.1.2 Small-Break LOCA

For small-break LOCA safety analysis, the relevant new features of the AP600 and the AP1000 designs are the core makeup tank, and the automatic depressurization system which depressurizes the primary system to near containment pressure.

The core makeup tank provides injection flow to the reactor vessel at any reactor coolant system pressure. The core makeup tank tests described above duplicated small-break conditions as well as the large-break conditions. The automatic depressurization system provides controlled venting of the reactor coolant system to reduce pressure to allow transition to gravity driven injection from the IRWST. Full-scale tests were conducted in the AP600 test program to obtain data on the performance of the automatic depressurization system. As shown by the AP1000 evaluations, these tests also support AP1000 safety analysis.

Automatic Depressurization System Hydraulic Tests

The purpose of these tests is to simulate the automatic depressurization system, to confirm the capacity of the automatic depressurization system valves and spargers, and to determine the dynamic effects on the IRWST structure.

A pressurized, heated water/steam source was used to simulate the water/steam flow rate from the AP600 reactor coolant system during various stages of the automatic depressurization system blowdown. Two test phases were conducted. Phase A consisted of steam only blowdowns at bounding volumetric flowrates. The flow is piped to a full sized sparger submerged in a quench tank simulating the IRWST. The Phase B1 portion of the test included steam/water blowdowns at bounding mass flowrates through a simulation of one of the two ADS stage 1,2,3 flowpaths. Instrumentation to measure water and steam flow rate, and IRWST dynamic loads was installed. Sparger behavior was obtained from ambient to fully saturated IRWST water temperatures.

1.5.1.3 Containment Cooling

Tests to characterize the heat removal capabilities of the AP600 containment design were performed to provide the database for the containment cooling models. These include the following:

- Study of water film behavior and wetting of a steel plate simulating the containment exterior surface
- Heated plate tests to examine the evaporating heat transfer of water from the steel surface of the containment and heat transfer with only air cooling
- Containment external cooling air flow path pressure drop tests to characterize the hydraulic losses
- Steam condensation heat transfer experiments on a flat cool surface at different angles of inclination to simulate the condensation on the inside of the containment in the presence of noncondensible gases

In addition, tests were performed to examine the integrated behavior of the steam condensation on the inside, and the evaporative film cooling and air cooling on the outside of a pressure vessel. The cylindrical vessel used for this integral test was 3 feet wide and 24 feet high. These experiments included transient and steady-state tests which have been used as the basis for the containment analyses. The limits of coolability and the effect of cold weather conditions were also examined.

As shown by the AP1000 evaluations, these tests also support AP1000 safety analysis.

Integral Containment Cooling Tests

This test examines the combined effect of natural convection and condensation on the interior of the containment while the exterior is cooled by film evaporation and air flow. This test demonstrated the operation of the passive containment cooling system over a range of operating conditions, including operation at low environmental temperatures. This test, in conjunction with completed conceptual design phase testing and the large scale containment test described below, characterize the passive containment cooling system design and performance.

Passive Containment Cooling System Heat Transfer Test

A one-eighth scale steel containment structure with external water film and natural circulation air cooling and modeled containment internal compartments was constructed.

This test accurately models both the containment dome and side wall heat transfer areas. It complements the integral containment experiment which simulates the side wall condensation and evaporating film heat transfer. This test was used to verify the containment analysis analytical methods.

Instrumentation measured the condensation heat flux distribution, the resulting heat transfer coefficients, the air/steam mass ratios, and the resulting liquid film evaporation rates. Both the current integral containment cooling test and this larger scale containment test have been modeled to verify the Chapter 15 analysis computer code and to demonstrate the scalability of the results.

Passive Containment Cooling System Water Distribution Test

A passive containment cooling system water distribution experiment was performed to examine and finalize the AP600 containment water distribution. The results provide input into the containment safety analysis computer codes for water coverage of the containment shell.

The test was performed on a full-scale 1/8th sector of the containment dome. The AP600 water supply/distribution arrangement was modeled. Tests were conducted to demonstrate and measure the water spreading from the top center of the dome to the outer edges. Tests have been conducted to verify the performance of the water distribution system design. Tests were conducted with the surface coated with the prototypic AP600 containment coating. Measurements of water film velocities and film thickness variation as a function of flow rate and radial distance on the dome were obtained.

Passive Containment Cooling System Wind Tunnel Tests

Containment cooling relies on natural circulation of air to enhance evaporative cooling of the containment shell during a design basis event. Wind tunnel tests were performed to demonstrate that wind does not adversely affect natural circulation air cooling through the shield building and around the containment shell.

An approximately 1/100-scale model of the AP600 plant, including the adjacent buildings and cooling tower structure, was constructed and instrumented with pressure taps. The model was placed in a boundary layer wind tunnel and tested at different wind directions. The results were used to design the shield building air inlet and exhaust arrangement and to determine the loads on the air baffle. Variations in site layout and topography have been addressed using an approximately 1/800-scale model of the site buildings and local topography.

Tests were also conducted in a larger, higher speed wind tunnel on an approximately 1/30-scale model. These tests were conducted to confirm that the early test results conservatively represented those expected at full scale Reynolds numbers and to obtain better estimates of the baffle loads in the presence of a cooling tower.

1.5.1.4 Non-LOCA Transient Analysis

The non-LOCA accidents are evaluated using the same transient analysis methods used on existing Westinghouse PWR designs. Passive core cooling system computer models have been developed and added to the transient analysis codes. These models consist of a core makeup tank model and a passive residual heat removal (PRHR) heat exchanger model. As shown by the AP1000 evaluations, these tests also support AP1000 safety analysis.

Passive Residual Heat Removal Heat Exchanger Performance Test

The PRHR heat exchanger is located in the IRWST. This heat exchanger, which is connected directly to the reactor coolant system, transfers core decay heat and sensible heat energy to the IRWST water and depends only on natural circulation driving forces.

The passive residual heat removal heat exchanger test determined the heat transfer characteristics of the PRHR heat exchanger and the mixing characteristics in the IRWST. These results confirm the heat exchanger size and configuration.

The test facility consisted of three full-length heat exchanger tubes placed vertically in a cylindrical tank filled with water and baffled to simulate the AP600 IRWST. Water at prototypic natural circulation and forced flow rates was run through the heat exchanger tubes at prototypic system pressure and temperatures. Data was taken with IRWST water cold to saturation temperature to define the PRHR heat transfer correlation. Tests were also conducted using a baffle to simulate the effect of other rows of tubes have on heat exchanger thermal performance and tank mixing.

Departure from Nucleate Boiling Test

Due to the shorter coastdown of the AP600 canned motor reactor coolant pumps, the flow rates at the time of minimum DNBR are somewhat below previously correlated flow rates. DNB testing was performed to extend the DNB correlation to these lower flows.

These critical heat flux tests were conducted using a 5x5, full length heated rod bundle with non-uniform radial and axial heating distributions.

1.5.1.5 Integral Systems Testing

In the AP600, the water injected into the reactor coolant system comes from the CMTs, accumulators, and the IRWST. Two integral systems tests were conducted in the AP600 test program, a low-pressure scaled test and a full-height, full-pressure test. In addition, the NRC conducted tests in the low-pressure scaled test facility (Reference 27). As shown in the AP1000 evaluations (Reference 25), these three test programs are sufficient to support AP1000 safety analysis.

Low-Pressure Integral Systems Test

The primary purpose of this experiment was to examine the operation of the long-term makeup path from the in-containment refueling water storage tank. In addition, analysis of this experiment demonstrates water flow through the core to limit the long-term concentration of boric acid. The facility is capable of simulating high-pressure system responses.

The test models the reactor vessel, steam generators, reactor coolant pumps, in-containment refueling water storage tank, the automatic depressurization system vent paths, the lower containment, and the connecting piping. The hot legs and cold legs are modeled as are the core makeup tanks, PRHR heat exchangers, accumulators, and pressurizer.

Water is the working fluid and the core is simulated with electric heater rods scaled to match the core power levels consistent with the test scaling approach. Tests were performed to simulate various small-break LOCAs with different break locations, break sizes, with and without nonsafety systems operating. The analysis methods in Chapter 15 were compared to the test.

Full-Height, Full-Pressure Integral Systems Test

A test was performed to provide data on system performance at high pressure. This test facility is configured as a full-height, full-pressure integral test with AP600 features including two loops with one hot leg and two cold legs per loop, two core makeup tanks, two accumulators, a PRHR heat exchanger and an automatic depressurization system. The facility includes a scaled reactor vessel, steam generators, pressurizer and reactor coolant pumps. Water is the working fluid and the core is simulated with electric heater rods.

Tests were performed simulating small break LOCAs, steam generator tube ruptures and a steam line break transient. The analysis methods in Chapter 15 were compared to the test results.

1.5.2 AP600 Component Design Tests

The component design tests will provide a larger database for design optimization during the detailed design of the plant. Tests on selected plant components were performed to confirm their reliability or that materials and fabrication methods meet ASME requirements. These tests are also applicable to the AP1000 design and analysis.

Incore Instrumentation System Tests

Systems similar to the AP600 and AP1000 top mounted fixed incore detector (FID) instrumentation have been demonstrated in operating plants. A test was performed to demonstrate that the system will not be susceptible to electro-magnetic interference (EMI) from the nearby control rod drive mechanisms.

The electro-magnetic interference test was performed by mocking up instrument cables, bringing them into close proximity with an operating control rod drive mechanism, and measuring the resulting noise induced on simulated flux signals.

Reactor Coolant Pump/Steam Generator Airflow Test

The airflow test was performed to identify effects on the pump performance due to non-uniform channel head flow distribution, pressure losses of the channel head nozzle dams and pump suction nozzle, and possible vortices in the channel head induced by the pump impeller rotation.

The air test facility was constructed as an approximate one-half scale mockup of the outlet half of the channel head, the two pump suction nozzles, and two pump impellers and diffusers. The channel head tube sheet was constructed from clear plastic to allow smoke flow stream patterns to be seen.

The results of the test showed no flow anomalies or vortices in the channel head were induced by the dual impellers.

Reactor Coolant Pump High Inertia Rotor/Bearing Tests

A rotor, manufactured of depleted uranium clad with stainless steel, has been incorporated into the hermetically sealed, high inertia centrifugal canned motor reactor coolant pump to provide the required flow coastdown performance for loss of flow transients.

Tests have been performed to verify manufacturability of the rotor, to determine friction and drag losses, to verify the operating performance of the pivoted-pad bearings, and to develop a detailed quantitative knowledge of the factors influencing bearing design and performance.

Tests were performed to verify the drag losses of the rotor with the journal bearing located on the pump shaft. Approximately 1000 cycles of starts and stops were also performed as a life test to demonstrate that the rotor will maintain its dimensional stability. These tests were performed on the specially-constructed, full-scale rotor/bearing test rig.

1.5.3 Combined License Information

This section has no requirement for additional information to be provided in support of the Combined License application.

1.5.4 References

1. WCAP-14217, "Core Makeup Tank Final Data Report," (Proprietary), WCAP-14218 (Nonproprietary), November 1994.

2. WCAP-13286, "AP600 Passive Core Cooling System Check Valve Test Final Report," (Proprietary), WCAP-13287 (Nonproprietary), April 1992.

3. WCAP-13891, "AP600 Automatic Depressurization System Phase A Test Data Report," (Proprietary), WCAP-14095 (Nonproprietary), May 1994.

4. WCAP-14324, "Final Data Report for ADS Phase B1 Tests," (Proprietary), WCAP-14325 (Nonproprietary), April 1995.

5. WCAP-14134, "AP600 Passive Containment Cooling System Integral Small-Scale Tests Final Report," (Proprietary), WCAP-14137 (Nonproprietary), August 1994.

6. WCAP-13566, "AP600 1/8th Large Scale Passive Containment Cooling System Heat Transfer Baseline Data Report," (Proprietary), Revision 1, WCAP-13567 (Nonproprietary), Revision 0, December 1992.

7. WCAP-14135, "Final Test Report for PCS Large Scale Phase 2 and Phase 3 Tests," (Proprietary), WCAP-14138 (Nonproprietary), Revision 3, September 1998.

8. WCAP-13353, "Passive Containment Cooling System Water Distribution Phase 1 Test Data Report," (Proprietary), WCAP-13354 (Nonproprietary), April 1992.

9. WCAP-13296, "PCS Water Distribution Test Phase II Test Data Report," (Proprietary), WCAP-13297 (Nonproprietary), March 1992.

10. WCAP-13960, "PCS Water Distribution Phase 3 Test Data Report," (Proprietary), WCAP-13961 (Nonproprietary), December 1993.

11. WCAP-13294, "Phase I Wind Tunnel Testing for the Westinghouse AP600 Reactor," (Proprietary), WCAP-13295 (Nonproprietary), April 1992.

12. WCAP-13323, "Phase II Wind Tunnel Testing for the Westinghouse AP600 Reactor," (Proprietary), WCAP-13324 (Nonproprietary), August 1992.

13. WCAP-14068, "Phase IVa Wind Tunnel Testing for the Westinghouse AP600 Reactor," (Proprietary), WCAP-14084 (Nonproprietary), May 1994.

14. WCAP-14169, "Phase IVa Wind Tunnel Testing for the Westinghouse AP600 Reactor, Supplemental Report," (Proprietary), WCAP-14170 (Nonproprietary), September 1994.

15. WCAP-14091, "Phase IVb Wind Tunnel Testing for the Westinghouse AP600 Reactor," (Proprietary), WCAP-14092 (Nonproprietary), July 1994.

16. WCAP-12980, "AP600 Passive Residual Heat Removal Heat Exchanger Test Final Report," (Proprietary), WCAP-13573 (Nonproprietary), Revision 3, April 1997.

17. WCAP-14371, "AP600 Low Flow Critical Heat Flux (CHF) Test Data Analysis," (Proprietary), WCAP-14372 (Nonproprietary), May 1995.

18. WCAP-14252, "AP600 Low Pressure 1/4 Height Integral Systems Tests - Final Data Report," (Proprietary), WCAP-14253 (Nonproprietary), Revision 1, November 1998.

19. WCAP-14309, "AP600 Design Certification Program, SPES-2 Tests Final Data Report," (Proprietary), WCAP-14310 (Nonproprietary), Revision 2, May 1997.

20. WCAP-12648, "AP600 Incore Instrumentation System Electromagnetic Interference Test Report," (Proprietary), WCAP-13322 (Nonproprietary), Revision 1, April 1992.

21. WCAP-13298, "RCP Air Model Test Report," (Proprietary), WCAP-13299 (Nonproprietary), August 1991.

22. WCAP-12668, "AP600 High Inertia Rotor Testing - Phase I, Test Report," (Proprietary), WCAP-13321 (Nonproprietary), March 1990.

23. WCAP-13319, "AP600 High Inertia Rotor Testing - Phase 2 Report," (Proprietary), WCAP-13320 (Nonproprietary), August 1991.

24. WCAP-13758, "High Inertia Rotor Test Phase 3 Report," (Proprietary), WCAP-13759 (Nonproprietary), June 1993.

25. WCAP-15613, "AP1000 PIRT and Scaling Assessment," (Proprietary), WCAP-15706 (Nonproprietary), March 2001.

26. Not used.

27. NUREG/CR-6641, "Final Report of NRC Research Conducted at Oregon State University," August 1999.

Table 1.5-1

AP600 DESIGN TESTS AND AP1000 EVALUATION

Test	Reference
LOCA Mitigation	
Core Makeup Tank Performance Test	(1)
Passive Safety Injection System Check Valve Test	(2)
Automatic Depressurization System Hydraulic Test	(3), (4)
Containment Cooling	
Integral Containment Cooling Test	(5)
Passive Containment Cooling System Heat Transfer Test	(6), (7)
Passive Containment Cooling System Water Distribution Test	(8), (9), (10)
Passive Containment Cooling System Wind Tunnel Test	(11), (12), (13), (14), (15)
Non-LOCA Transients	
Passive Residual Heat Removal Heat Exchanger Performance Test	(16)
Departure from Nucleate Boiling Test	(17)
Integral Systems Tests	
Low Pressure Integral Systems Test	(18)
Full Height Full Pressure Integral Systems Test	(19)
NRC Low Pressure Integral Systems Test	(27)
Component Design Tests	
Incore Instrumentation System Test	(20)
Reactor Coolant Pump/Steam Generator Airflow Test	(21)
Reactor Coolant Pump High Inertia Rotor/Bearing Test	(22), (23), (24)
AP1000 Evaluation	
AP1000 PIRT and Scaling Assessment	(25)

1.6 Material Referenced

The AP1000 Design Control Document references various Westinghouse technical support documents; these documents are listed by DCD section in Table 1.6-1 (Sheets 1 through 20).

Table 1.6-1 (Sheet 1 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
1.5	WCAP-14217 (P) WCAP-14218	Core Makeup Tank Final Data Report, November 1994
	WCAP-13286 (P) WCAP-13287	AP600 Passive Core Cooling System Check Valve Test Final Report, April 1992
	WCAP-13891 (P) WCAP-14095	AP600 Automatic Depressurization System Phase A Test Data Report, May 1994
	WCAP-14324 (P) WCAP-14325	Final Data Report for ADS Phase B1 Tests, April 1995
	WCAP-14134 (P) WCAP-14137	AP600 Passive Containment Cooling System Integral Small-Scale Tests Final Report, August 1994
	WCAP-13566 (P) WCAP-13567	AP600 1/8th Large Scale Passive Containment Cooling System Heat Transfer Baseline Data Report, Revision 1, December 1992
	WCAP-14135 (P) WCAP-14138	Final Test Report for PCS Large Scale Phase 2 and Phase 3 Tests, Revision 3, September 1998
	WCAP-13353 (P) WCAP-13354	Passive Containment Cooling System Water Distribution Phase 1 Test Data Report, April 1992
	WCAP-13296 (P) WCAP-13297	PCS Water Distribution Test Phase II Test Data Report, March 1992
	WCAP-13960 (P) WCAP-13961	PCS Water Distribution Phase 3 Test Data Report, December 1993
	WCAP-13294 (P) WCAP-13295	Phase I Wind Tunnel Testing for the Westinghouse AP600 Reactor, April 1992
	WCAP-13323 (P) WCAP-13324	Phase II Wind Tunnel Testing for the Westinghouse AP600 Reactor, August 1992
	WCAP-14068 (P) WCAP-14084	Phase IVa Wind Tunnel Testing for the Westinghouse AP600 Reactor, May 1994

(P) Denotes Document is Proprietary

Table 1.6-1 (Sheet 2 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
1.5	WCAP-14169 (P) WCAP-14170	Phase IVa Wind Tunnel Testing for the Westinghouse AP600 Reactor, Supplemental Report, September 1994
	WCAP-14091 (P) WCAP-14092	Phase IVb Wind Tunnel Testing for the Westinghouse AP600 Reactor, July 1994
	WCAP-12980 (P) WCAP-13573	AP600 Passive Residual Heat Removal Heat Exchanger Test Final Report, Revision 3, April 1997
	WCAP-14371 (P) WCAP-14372	AP600 Low Flow Critical Heat Flux (CHF) Test Data Analysis, May 1995
	WCAP-14252 (P) WCAP-14253	AP600 Low Pressure 1/4 Height Integral Systems Tests - Final Data Report, Revision 1, November 1998
	WCAP-14309 (P) WCAP-14310	AP600 Design Certification Program, SPES-2 Tests Final Data Report, Revision 2, May 1997
	WCAP-12648 (P) WCAP-13322	AP600 Incore Instrumentation System Electromagnetic Interference Test Report, Revision 1, April 1992
	WCAP-13298 (P) WCAP-13299	RCP Air Model Test Report, August 1991
	WCAP-12668 (P) WCAP-13321	AP600 High Inertia Rotor Testing - Phase I, Test Report, March 1990
	WCAP-13319 (P) WCAP-13320	AP600 High Inertia Rotor Testing - Phase 2 Report, August 1991
	WCAP-13758 (P) WCAP-13759	High Inertia Rotor Test - Phase 3 Report, June 1993
	WCAP-15613 (P) WCAP-15706	AP1000 PIRT and Scaling Assessment Report, March 2001

(P) Denotes Document is Proprietary

Table 1.6-1 (Sheet 3 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
1.9	WCAP-15993	Evaluation of the AP1000 Conformance to Inter-System Loss-of-Coolant Accident Acceptance Criteria, Revision 1, March 2003
	WCAP-15799	AP1000 Compliance with SRP Acceptance Criteria, Revision 1, August 2003
	WCAP-15800	Operational Assessment for AP1000, Revision 3, July 2004
	WCAP-15992	AP1000 Adverse Systems Interactions Evaluation Report, Revision 1, February 2003
	WCAP-15776	Safety Criteria for the AP1000 Instrumentation and Control Systems
1A	WCAP-8577	The Application of Pre-Heat Temperature After Welding of Pressure Vessel Steels, September 1975
	WCAP-15783-P (P) WCAP-15783-NP	Analysis of the Probability of the Generation of Missiles from Fully Integral Nuclear Low Pressure Turbines, Revision 2, August 2003
3.3	WCAP-13323 (P) WCAP-13324	Phase II Wind Tunnel Testing for the Westinghouse AP600 Reactor, August 1992
	WCAP-14068 (P) WCAP-14084	Phase IVA Wind Tunnel Testing for the Westinghouse AP600 Reactor, May 1994
	WCAP-14169 (P) WCAP-14170	Phase IVA Wind Tunnel Testing for the Westinghouse AP600 Reactor, Supplemental Report, September 1994
	WCAP-13294-P (P) WCAP-13295-NP	Phase I Wind Tunnel Testing for the Westinghouse AP600 Reactor, April 1992
3.6	WCAP-8077 (P) WCAP-8078	Ice Condenser Containment Pressure Transient Analysis Methods, March 1973
	WCAP-8708 (P) WCAP-8709-A	MULTIFLEX A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics, February 1976
	WCAP-8252	Documentation of Selected Westinghouse Structural Analysis Computer Codes, Revision 1, May 1977

(P) Denotes Document is Proprietary

Table 1.6-1 (Sheet 4 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
3.7	WCAP 7921-AR	Damping Values of Nuclear Power Plant Components, May 1974
	WCAP-9903 (P)	Justification of the Westinghouse Equivalent Static Analysis Method for Seismic Qualification of Nuclear Power Plant Auxiliary Mechanical Equipment, August 1980
3.8	WCAP-13891 (P) WCAP-14095	AP600 Automatic Depressurization System Phase A Test Data Report, May 1994
	WCAP-14324 (P) WCAP-14325	Final Data Report for ADS Phase B1 Tests, April 1995
	WCAP-15613 (P) WCAP-15706	AP1000 PIRT and Scaling Assessment, March 2001
3.9	WCAP-7765-AR	Westinghouse PWR Internals Vibrations Summary Three-Loop Internals Assurance, November 1973
	WCAP-8766 (P) WCAP-8780	Verification of Neutron Pad and 17x17 Guide Tube Designs by Preoperational Tests on the Trojan 1 Power Plant, May 1976
	WCAP-8516-P (P) WCAP-8517	UHI Plant Internals Vibrations Measurement Program and Pre- and Post-Hot Functional Examinations, March 1975
	WCAP-10846 (P)	Doel 4 Reactor Internals Flow-Induced Vibration Measurement Program, March 1985
	WCAP-10865 (P) WCAP-10866	South Texas Plant (TGX) Reactor Internals Flow-Induced Vibration Assessment, February 1985
	WCAP-8708-P-A (P) Volumes 1 and 2 WCAP-8709-A Volumes 1 and 2	MULTIFLEX A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics, February 1976
	WCAP-8446 (P) WCAP-8449	17x17 Drive Line Components Tests – Phase 1B 11, 111 D-Loop Drop and Deflection, December 1974
	WCAP-9693 (P)	Investigation of Feedwater Line Cracking in Pressurized Water Reactor Plants, June 1980
	WCAP-15949-P (P) WCAP-15949-NP	AP1000 Reactor Internals Flow-Induced Vibration Assessment Program, Revision 1, July 2003

(P) Denotes Document is Proprietary

Table 1.6-1 (Sheet 5 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
4.1	WCAP-10444-P-A (P) WCAP-10445-NP-A	Reference Core Report VANTAGE 5 Fuel Assembly, September 1985, and VANTAGE 5H Fuel Assembly, Addendum 2A, February 1989
	WCAP-12610-P-A (P) WCAP-14342-A	VANTAGE+ Fuel Assembly Reference Core Report, April 1995
	[*WCAP-12488-A (P)* [*WCAP-14204-A*]*	*Fuel Criteria Evaluation Process, October 1994*]*
4.2	[*WCAP-12488-A (P)* [*WCAP-14204-A*]*	*Fuel Criteria Evaluation Process, October 1994*]*
	WCAP-10125-P-A (P) WCAP-10126-NP-A	Extended Burnup Evaluation of Westinghouse Fuel, December 1985
	WCAP-8183	Operational Experience with Westinghouse Cores (Revised Annually)
	WCAP-9179 (P) WCAP-9224	Properties of Fuel and Core Component Materials, July 1978
	WCAP-12610-P-A (P) WCAP-14342-A	VANTAGE+ Fuel Assembly Reference Core Report, June 1990/April 1995
	WCAP-8218-P-A (P) WCAP-8219-A	Fuel Densification Experimental Results and Model for Reactor Application, March 1975
	WCAP-10851-P-A (P) WCAP-11873-A	Improved Fuel Performance Models for Westinghouse Fuel Rod Design and Safety Evaluations, August 1988
	WCAP-13589-A (P) WCAP-14297-A	Assessment of Clad Flattening and Densification Power Spike Factor Elimination in Westinghouse Nuclear Fuel, March 1995
	WCAP-8963-P-A (P) WCAP-8964-A	Safety Analysis for the Revised Fuel Rod Internal Pressure Design Basis, August 1977
	WCAP-10021-P-A (P) WCAP-10377-NP-A	Westinghouse Wet Annular Burnable Absorber Evaluation Report, Revision 1, October 1983
	WCAP-10444-P-A (P) WCAP-10445-NP-A	Reference Core Report VANTAGE 5 Fuel Assembly, September 1985

(P) Denotes Document is Proprietary

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 1.6-1 (Sheet 6 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
4.2	WCAP-8278 (P) WCAP-8279	Hydraulic Flow Test of the 17x17 Fuel Assembly, February 1974
	WCAP-8691 (P) WCAP-8692	Fuel Rod Bow Evaluation, Revision 1, July 1979
	WCAP-9500-P-A (P) WCAP-9500-A	Reference Core Report 17x17 Optimized Fuel Assembly, May 1982
	WCAP-8236 (P) WCAP-8288	Safety Analysis of the 17x17 Fuel Assembly for Combined Seismic and Loss-of-Coolant Accident, December 1973
	WCAP-9401-P-A (P) WCAP-9402-A	Verification, Testing, and Analysis of the 17x17 Optimized Fuel Assembly, August 1981
	WCAP-9283	Integrity of Primary Piping Systems of Westinghouse Nuclear Power Plants During Postulated Seismic Events, March 1978
	WCAP-15063-P-A (P) WCAP-15064-NP-A	Westinghouse Improved Performance Analysis and Design Model (PAD 4.0), Rev. 1, July 2000
	WCAP-8377 (P)	Revised Clad Flattening Model, July 1974
4.3	WCAP-9272-P-A (P) WCAP-9273-NP-A	Westinghouse Reload Safety Evaluation Methodology, July 1985
	[*WCAP-12488-P-A (P)* [*WCAP-14204-A*]*	*Fuel Criteria Evaluation Process, October 1994*]*
	WCAP-12472-P-A (P) WCAP-12473-A	BEACON: Core Monitoring and Operations Support System, August 1994; Addendum 1, May 1996; Addendum 2, March 2001
	WCAP-8330	Westinghouse Anticipated Transients Without Reactor Trip Analysis, August 1974
	WCAP-7308-L-P-A (P) WCAP-7308-L-A	Evaluation of Nuclear Hot Channel Factor Uncertainties, June 1988
	WCAP-8218-P-A (P) WCAP-8219-A	Fuel Densification Experimental Results and Model for Reactor Application, March 1975
	WCAP-8359	Effects of Fuel Densification Power Spikes on Clad Thermal Transients, July 1974

(P) Denotes Document is Proprietary
*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 1.6-1 (Sheet 7 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
4.3	WCAP-7811	Power Distribution Control of Westinghouse Pressurized Water Reactors, December 1971
	WCAP-8385 (P) WCAP-8403	Power Distribution Control and Load Following Procedures, September 1974
	WCAP-10216-P-A (P) WCAP-10217-A	Relaxation of Constant Axial Offset Control, F_Q Surveillance Technical Specification, Revision 1A, February 1994
	WCAP-7912-P-A (P) WCAP-7912-A	Power Peaking Factors, January 1975
	WCAP-8498	Incore Power Distribution Determination in Westinghouse Pressurized Water Reactors, July 1975
	WCAP-9217 (P) WCAP-9218	Results of Control Rod Worth Program, October 1977
	WCAP-3696-8 (P)	Pressurized Water Reactor pH – Reactivity Effect Final Report, October 1968
	WCAP-3680-20 (P)	Xenon-Induced Spatial Instabilities in Large Pressurized Water Reactors, March 1968
	WCAP-3680-21 (P)	Control Procedures for Xenon-Induced X-Y Instabilities in Large Pressurized Water Reactors, February 1969
	WCAP-3680-22 (P)	Xenon-Induced Spatial Instabilities in Three Dimensions, September 1969
	WCAP-7964	Axial Xenon Transient Tests at the Rochester Gas and Electric Reactor, June 1971
	WCAP-7048-P-A (P) WCAP-7757-A	The PANDA Code, February 1975
	WCAP-7213-A (P) WCAP-7758-A	The TURTLE 24.0 Diffusion Depletion Code, February 1975
	WCAP-8768	Safety-Related Research and Development for Westinghouse Pressurized Water Reactors, Program Summaries – Winter 1977 – Summer 1978, Revision 2, October 1978

(P) Denotes Document is Proprietary

Table 1.6-1 (Sheet 8 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
4.3	WCAP-6073 (P)	LASER – A Depletion Program for Lattice Calculations Based on MUFT and THERMOS, April 1966
	WCAP-2048 (P)	The Doppler Effect for a Non-Uniform Temperature Distribution in Reactor Fuel Elements, July 1962
	WCAP-11596-P-A (P) WCAP-11597-A	Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores, June 1988
	WCAP-10841 (P) WCAP-10842	Qualification of the PHOENIX/POLCA Nuclear Design and Analysis Program for Boiling Water Reactors, June 1985
	WCAP-7806	Nuclear Design of Westinghouse Pressurized Water Reactors with Burnable Poison Rods, December 1971
	WCAP-3385-56 Part II	Saxton Core II Fuel Performance Evaluation Part II: Evaluation of Mass Spectrometric and Radiochemical Analysis of Irradiated Saxton Plutonium Fuel, July 1973
	WCAP-3385-56 Part I	Saxton Core II - Fuel Performance Evaluation Part I: Materials, September 1971
	WCAP-3385-36	Saxton Plutonium Project - Quarterly Progress Report for the Period Ending June 20, 1973, July 1973
	WCAP-3385-37	Saxton Plutonium Project - Quarterly Progress Report for the Period Ending September 30, 1973, December 1973
	WCAP-3017-6094	Yankee Core Evaluation Program Final Report, January 1971
	WCAP-10965-P-A (P) WCAP-10966-A	ANC: A Westinghouse Advanced Nodal Computer Code, September 1986
	WCAP-3726-1	PuO_2-UO_2 Fueled Critical Experiments, July 1967
	WCAP-13589-A (P) WCAP-14297-A	Assessment of Clad Flattening and Densification Power Spike Factor Elimination in Westinghouse Nuclear Fuel, March 1995
	WCAP-13524 (P) WCAP-14952-NP-A	APOLLO - A One Dimensional Neutron Theory Program, Revision 1, August 1994

(P) Denotes Document is Proprietary

Table 1.6-1 (Sheet 9 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
4.4	WCAP-11397-P-A (P) WCAP-11397-A	Revised Thermal Design Procedure, April 1989
	WCAP-6065 (P)	Melting Point of Irradiated UO_2, February 1965
	WCAP-10444-P-A (P) WCAP-10445-NP-A	Reference Core Report VANTAGE 5 Fuel Assembly, September 1985
	WCAP-9226-P (P) WCAP-9227-NP	Reactor Core Response to Excessive Secondary Steam Releases, January 1989
	WCAP-7695-L (P)	DNB Test Results for R-Grid Thimble Cold Wall Cells, Addendum 1, October 1972
	[*WCAP-12488-A (P)*	*Westinghouse Fuel Criteria Evaluation Process, October 1994*]*
	WCAP-7941-P-A (P) WCAP-7959-A	Effect of Axial Spacing on Interchannel Thermal Mixing with the R Mixing Vane Grid, January 1975
	WCAP-8298-P-A (P) WCAP-8290-A	The Effect of 17x17 Fuel Assembly Geometry on Interchannel Thermal Mixing, January 1975
	WCAP-8174 (P) WCAP-8202-A	Effect of Local Heat Flux Spikes on DNB in Non Uniform Heated Rod Bundles, August 1973
	WCAP-7667-P-A (P) WCAP-7755-A	Interchannel Thermal Mixing with Mixing Vane Grids, January 1975
	WCAP-8691 (P) WCAP-8692	Fuel Rod Bow Evaluation, Revision 1, July 1979
	WCAP-8054-P-A (P) WCAP-8195-A	Applications of THINC-IV Program to PWR Design, October 1973
	WCAP-7956-P-A (P)	THINC-IV, An Improved Program for Thermal-Hydraulic Analysis of Rod Bundle Cores, February 1989
	WCAP-2923	In-Pile Measurement of UO_2 Thermal Conductivity, March 1966
	WCAP-10851-P-A (P) WCAP-11873-A	Improved Fuel Performance Models for Westinghouse Fuel Rod Design and Safety Evaluations, August 1988
	WCAP-8720 Addendum 2	Revised PAD Code Thermal Safety Model, October 1982

(P) Denotes Document is Proprietary
*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 1.6-1 (Sheet 10 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
4.4	WCAP-6069	Burnup Physics of Heterogeneous Reactor Lattices, June 1965
	WCAP-3385-56 Part II	Saxton Core II Fuel Performance Evaluation: Evaluation of Mass Spectrometric and Radiochemical Analyses of Irradiated Saxton Plutonium Fuel, July 1970
	WCAP-7912-P-A (P) WCAP-7912-A	Power Peaking Factors, January 1975
	WCAP-8453-A	Analysis of Data from the Zion (Unit 1) THINC Verification Test, May 1976
	WCAP-12610-P-A (P) WCAP-14342-A	VANTAGE+ Fuel Assembly Reference Core Report, April 1995
	WCAP-15025-P-A (P) WCAP-15026-NP-A	Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17x17 Rod Bundles with Modified LPD Mixing Vane Grids, April 1999
	WCAP-14565-P-A (P) WCAP-15306-NP-A	VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, October 1999
	WCAP-15063-P-A (P) WCAP-15064-NP-A	Westinghouse Improved Performance Analysis and Design Model (PAD 4.0), Rev. 1, July 2000
5.2	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984
	WCAP-9292	Dynamic Fracture Toughness of ASME SA-508 Class 2a and ASME SA-533 Grade A Class 2 Base and Heat-Affected Zone Material and Applicable Weld Metals, March 1978
	WCAP-7477-L (P) WCAP-7735	Sensitized Stainless Steel in Westinghouse PWR Nuclear Steam Supply Systems, March 1970 (P), August 1971 (Non-P)
	WCAP-8324-A	Control of Delta Ferrite in Austenitic Stainless Steel Weldments, June 1975
	WCAP-8693	Delta Ferrite in Production Austenitic Stainless Steel Weldments, January 1976

(P) Denotes Document is Proprietary

Table 1.6-1 (Sheet 11 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
5.3	WCAP-15557	Qualification of the Westinghouse Pressure Vessel Neutron Fluence Evaluation Methodology, August 2000
	WCAP-14040-NP-A	Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves, Revision 2, January 1996
5.4	WCAP-15994-P (P) WCAP-15994-NP	Structural Analysis Summary for the AP1000 Reactor Coolant Pump High Inertia Flywheel, March 2003
6.2	WCAP-8077 (P) WCAP-8078	Ice Condenser Containment Pressure Transient Analysis Methods, March 1973
	WCAP-8264-P-A (P) WCAP-8312-A	Westinghouse Mass and Energy Release Data for Containment Design, June 1975 (P), August 1975 (Non-P)
	WCAP-10325-P-A (P) WCAP-10326-A	Westinghouse LOCA Mass and Energy Release Model for Containment Design - March 1979 Version, May 1983
	WCAP-8822 (P) WCAP-8860	Mass and Energy Releases Following A Steam Line Rupture, September 1976
	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984
	WCAP-15846 (P) WCAP-15862	WGOTHIC Application to AP600 and AP1000, Revision 1, March 2004
	WCAP-15965-P (P) WCAP-15965-NP	AP1000 Subcompartment Models, November 2002
	WCAP-14234 (P) WCAP-14235	LOFTRAN and LOFTTR2 AP600 Code Applicability Document, Revision 1, August 1997
	WCAP-15644-P (P) WCAP-15644-NP	AP1000 Code Applicability Report, Revision 2, March 2004
6.3	WCAP-8966 (P)	Evaluation of Mispositioned ECCS Valves, September 1977
	WCAP-13594 (P) WCAP-13662	FMEA of Advanced Passive Plant Protection System, Revision 1, June 1998

(P) Denotes Document is Proprietary

Table 1.6-1 (Sheet 12 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
6A	WCAP-15846 (P) WCAP-15862	WGOTHIC Application to AP600 and AP1000, Revision 1, March 2004
	WCAP-14135 (P) WCAP-14138	Final Data Report for Passive Containment Cooling System Large Scale Test, Phase 2 and Phase 3, Revision 3, November 1998
	WCAP-15613 (P) WCAP-15706	AP1000 PIRT and Scaling Assessment Report, March 2001
7.1	WCAP-13382 (P) WCAP-13391	AP600 Instrumentation and Control Hardware Description, May 1992
	[*WCAP-13383*	*AP600 Instrumentation and Control Hardware and Software Design, Verification, and Validation Process Report, Revision 1, June 1996*]*
	[*WCAP-14605 (P)* *WCAP-14606*	*Westinghouse Setpoint Methodology for Protection Systems - AP600, April 1996*]*
	WCAP-14080 (P) WCAP-14081	AP600 Instrumentation and Control Software Architecture and Operation Description, June 1994
	WCAP-15775	AP1000 Instrumentation and Control Defense-in-Depth and Diversity Report, Revision 2, March 2003
	[*CE-CES-195*	*Software Program Manual for Common Q Systems, Revision 01, May 2000*]*
	[*CENPD-396-P (P)* *WCAP-16097-NP-A*	*Common Qualified Platform, Revision 01, May 2000*]*
	[*WCAP-15927*	*Design Process for AP1000 Common Q Safety Systems, August 2002*]*
	WCAP-15776	Safety Criteria for the AP1000 Instrumentation and Control Systems, April 2002
7.2	WCAP-13594 (P) WCAP-13662	FMEA of Advanced Passive Plant Protection System, Revision 1, June 1998
	WCAP-15776	Safety Criteria for the AP1000 Instrumentation and Control Systems, April 2002
7.3	WCAP-15776	Safety Criteria for the AP1000 Instrumentation and Control Systems, April 2002

(P) Denotes Document is Proprietary
*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 1.6-1 (Sheet 13 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
9.5	WCAP-15871	AP1000 Assessment Against NFPA 804, Revision 1, December 2002
10.2	WCAP-15783-P (P) WCAP-15783-NP	Analysis of the Probability of the Generation of Missiles from Fully Integral Nuclear Low Pressure Turbines, Revision 2, August 2003
	WCAP-15785 (P) WCAP-15786	Probabilistic Evaluation of Turbine Valve Test Frequency, April 2002
13	WCAP-14690	Designer's Input to Procedure Development for the AP600, Revision 1, June 1997
	WCAP-13864	Rod Control System Evaluation Program, Revision 1-A, November 1994
15.0	WCAP-11397-P-A (P) WCAP-11397-A	Revised Thermal Design Procedure, April 1989
	WCAP-10054-P-A (P) WCAP-10081	Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code, August 1985
	WCAP-12945-P-A (P) WCAP-14747	Code Qualification Document for Best Estimate LOCA Analysis, Revision 1, March 1998
	WCAP-7908-A	FACTRAN – A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod, December 1989
	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984
	WCAP-7979-P-A (P) WCAP-8028-A	TWINKLE – A Multi-Dimensional Neutron Kinetics Computer Code, January 1975
	WCAP-10698-P-A (P) WCAP-10750-A	SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill, August 1987
	WCAP-14234 (P) WCAP-14235	LOFTRAN and LOFTTR2 AP600 Code Applicability Document, Revision 1, August 1997
	WCAP-15644-P (P) WCAP-15644-NP	AP1000 Code Applicability Report, Revision 2, March 2004
15.1	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984

(P) Denotes Document is Proprietary

Table 1.6-1 (Sheet 14 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
15.1	WCAP-11397-P-A (P) WCAP-11397-A	Revised Thermal Design Procedure, April 1989
	WCAP-9226 (P) WCAP-9227	Reactor Core Response to Excessive Secondary Steam Releases, January 1978
	WCAP-7908-A	FACTRAN – A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod, December 1989
15.2	WCAP-7769	Overpressure Protection for Westinghouse Pressurized Water Reactors, Revision 1, June 1972
	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984
	WCAP-9230 (P) WCAP-9231	Report on the Consequences of a Postulated Main Feedline Rupture, January 1978
	WCAP-11397-P-A (P) WCAP-11397-A	Revised Thermal Design Procedure, April 1989
	WCAP-15644-P (P) WCAP-15644-NP	AP1000 Code Applicability Report, Revision 2, March 2004
	WCAP-7908-A	FACTRAN - A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod, December 1989
15.3	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984
	WCAP-7908-A	FACTRAN - A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod, December 1989
	WCAP-8424	An Evaluation of Loss of Flow Accidents Caused by Power System Frequency Transients in Westinghouse PWRs, Revision 1, May 1975
	WCAP-11397-P-A (P) WCAP-11397-A	Revised Thermal Design Procedure, April 1989
15.4	WCAP-7979-P-A (P) WCAP-8028-A	TWINKLE - A Multi-Dimensional Neutron Kinetics Computer Code, January 1975
	WCAP-7908-A	FACTRAN - A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod, December 1989

(P) Denotes Document is Proprietary

Table 1.6-1 (Sheet 15 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
15.4	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984
	WCAP-7588	An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors Using Spatial Kinetics Methods, Revision 1A, January 1975
	WCAP-10965-P-A (P) WCAP-10966-A	ANC: A Westinghouse Advanced Nodal Computer Code, September 1986
	WCAP-11397-P-A (P) WCAP-11397-A	Revised Thermal Design Procedure, April 1989
	WCAP-15644-P (P) WCAP-15644-NP	AP1000 Code Applicability Report, Revision 2, March 2004
15.5	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984
15.6	WCAP-10924-P-A (P)	Westinghouse Large Break Best Estimate Methodology, Volume 1 Model Description and Validation, Volume 2, Revision 2, Application to Two-Loop PWRs Equipped with Upper Plenum Injection, December 1988
	WCAP-12945-P-A (P) WCAP-14747	Code Qualification Document for Best Estimate Analysis, Revision 2, March 1998
	WCAP-10079-P-A (P) WCAP-10080-A	NOTRUMP – A Nodal Transient Small Break and General Network Code, August 1985
	WCAP-10054-P-A (P) WCAP-10081-A	Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code, August 1985
	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984
	WCAP-7908-A	FACTRAN – A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod, December 1989
	WCAP-11397-P-A (P) WCAP-11397-A	Revised Thermal Design Procedure, April 1989
	WCAP-10698-P-A (P) WCAP-10750-A	SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill, August 1987

(P) Denotes Document is Proprietary

Table 1.6-1 (Sheet 16 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
15.6	WCAP-14206 (P) WCAP-14207	Applicability of the NOTRUMP Computer Code to AP600 SSAR Small-Break LOCA Analyses, November 1994
	WCAP-14601 (P) WCAP-15062	AP600 Accident Analyses – Evaluation Models, Revision 2, May 1998
	WCAP-14234 (P) WCAP-14235	LOFTRAN and LOFTTR2 AP600 Code Applicability Document, Revision 1, August 1997
	WCAP-14171 (P) WCAP-14172	WCOBRA/TRAC Applicability to AP600 Large-Break Loss-of-Coolant Accident, Revision 2, March 1998
	WCAP-14807 (P) WCAP-14808	NOTRUMP Final Validation Report for AP600, Revision 5, August 1998
	WCAP-14776 (P) WCAP-14777	WCOBRA/TRAC OSU Long-Term Cooling Final Validation Report, Revision 4, April 1998
	WCAP-15644-P (P) WCAP-15644-NP	AP1000 Code Applicability Report, Revision 2, March 2004
	WCAP-15613 (P) WCAP-15706	AP1000 PIRT and Scaling Assessment, March 2001
16.1	WCAP-9272-P-A (P) WCAP-9273-NP-A	Westinghouse Reload Safety Evaluation Methodology, July 1985
	WCAP-8385 (P) WCAP-8403	Power Distribution Control and Load Following Procedures, September 1974
	WCAP-10216-P-A (P) WCAP-10217-A	Relaxation of Constant Axial Offset Control F_Q Surveillance Technical Specifications, Revision 1A, February 1994
	WCAP-12945-P-A (P) WCAP-14747	Code Qualification Document for Best Estimate Loss of Coolant Accident Analysis, Revision 1, March 1998
	WCAP-12472-P-A (P) WCAP-12473-A	BEACON Core Monitoring and Operations Support System, August 1994, and Addendum 1, May 1996
	WCAP-7308-L-P-A (P) WCAP-7308-L-A	Evaluation of Nuclear Hot Channel Factor Uncertainties, June 1988

(P) Denotes Document is Proprietary

Table 1.6-1 (Sheet 17 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
16.1	WCAP-9273-NP-A	Westinghouse Reload Safety Evaluation Methodology, July 1985
	WCAP-14606	Westinghouse Setpoint Methodology for Protection Systems, April 1996
	WCAP-10271-P-A (P) WCAP-10272-A	Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System, June 1996
	WCAP-7924-A	Basis for Heatup and Cooldown Limit Curves, April 1975
	WCAP-13632-P-A (P) WCAP-13787-A	Elimination of Pressure Sensor Response Time Testing Requirements, Revision 2, January 1996
	WCAP-7769	Topical Report on Overpressure Protection, October 1971
	WCAP-15985	AP1000 Implementation of the Regulatory Treatment of Nonsafety-Related Systems Process, Revision 2, August 2003
17.6	WCAP-8370	Energy Systems Business Unit – Power Generation Business Unit Quality Assurance Plan, Revision 12a
	WCAP-8370/7800	Energy Systems Business Unit – Nuclear Fuel Business Unit Quality Assurance Plan, Revision 11A/7A
	WCAP-12600	AP600 Advanced Light Water Reactor Design Quality Assurance Program Plan, Revision 4, January 1998
18.1	WCAP-14645	Human Factors Engineering Operating Experience Review Report for the AP600 Nuclear Power Plant, Revision 2, December 1996
	WCAP-14644	AP600 Functional Requirements Analysis and Function Allocation, September 1996
	WCAP-14694	Designer's Input to Determination of the AP600 Main Control Room Staffing Level, July 1996
	[*WCAP-14651*	*Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan, Revision 2, May 1997*]*
	WCAP-14690	Designer's Input to Procedure Development for the AP600, Revision 1, June 1997

(P) Denotes Document is Proprietary
*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 1.6-1 (Sheet 18 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
18.1	WCAP-14655	Designer's Input to the Training of the Human Factors Engineering Verification and Validation Personnel, Revision 1, August 1996
	[*WCAP-15860*	*Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan, Revision 2, October 2003*]*
18.2	WCAP-14645	Human Factors Engineering Operating Experience Review Report for the AP600 Nuclear Power Plant, Revision 2, December 1996
	WCAP-14694	Designer's Input to Determination of the AP600 Main Control Room Staffing Level, July 1996
	[*WCAP-15847*	*AP1000 Quality Assurance Procedures Supporting NRC Review of AP1000 DCD Sections 18.2 and 18.8, Rev. 1, December 2002*]*
	WCAP-14644	AP600 Functional Requirements Analysis and Function Allocation, September 1996
18.3	WCAP-14645	Human Factors Engineering Operating Experience Review Report for the AP600 Nuclear Power Plant, Revision 2, December 1996
18.4	WCAP-14644	AP600 Functional Requirements Analysis and Function Allocation, September 1996
18.5	WCAP-10170	Emergency Response Facilities Design and V&V Process, April 1982
	[*WCAP-14695*	*Description of the Westinghouse Operator Decision Making Model and Function Based Task Analysis Methodology, July 1996*]*
	[*WCAP-14651*	*Integration of Human Reliability Analysis and Human Factors Engineering Design Implementation Plan, Revision 2, May 1997*]*
18.6	WCAP-14694	Designer's Input to Determination of the AP600 Main Control Room Staffing Level, July 1996
18.7	[*WCAP-14651*	*Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan, Revision 2, May 1997]**
18.8	[*WCAP-14651*	*Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan, Revision 2, May 1997]**
	[*WCAP-15860*	*Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan, Revision 2, October 2003]**
	[*WCAP-14695*	*Description of the Westinghouse Operator Decision Making Model and Function Based Task Analysis Methodology, July 1996]**

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 1.6-1 (Sheet 19 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
18.8	WCAP-14655	Designer's Input to the Training of the Human Factors Engineering Verification and Validation Personnel, Revision 1, August 1996
	WCAP-14690	Designer's Input to Procedure Development for the AP600, Revision 1, June 1997
	WCAP-10170	Emergency Response Facilities Design and V&V Process, April 1982
	WCAP-14694	Designer's Input to Determination of the AP600 Main Control Room Staffing Level, July 1996
	[*WCAP-14396*	*Man-in-the-Loop Test Plan Description, Revision 3, November 2002*]*
18.9	WCAP-14690	Designer's Input to Procedure Development for the AP600, Revision 1, June 1997
18.10	WCAP-14655	Designer's Input to the Training of the Human Factors Engineering Verification and Validation Personnel, Revision 1, August 1996
18.11	[*WCAP-15860*	*Programmatic Level Description of the AP1000 Human Factors Verification and Validation Plan, Revision 2, October 2003*]*
18.12	[*WCAP-14651*	*Integration of Human Reliability Analysis with Human Factors Engineering Design Implementation Plan, Revision 2, May 1997*]*
	WCAP-13793	The AP600 System/Event Matrix, June 1994
19.41.13	WCAP-13388 (P) WCAP-13389	AP600 Phenomenological Evaluation Summaries, (Prop - Rev. 0, June 1992, Non-Prop - Rev. 1, 1994)
19.59	WCAP-13914	Framework for AP600 Severe Accident Management Guidance, Revision 3, January 1998
19B	WCAP-13388 (P) WCAP-13389	AP600 Phenomenological Evaluation Summaries (Prop - Rev. 0, June 1992, Non-Prop - Rev. 1, 1994)
19D	WCAP-13914	Framework for AP600 Severe Accident Management Guidance, Revision 3, January 1998

(P) Denotes Document is Proprietary

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 1.6-1 (Sheet 20 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
19E	WCAP-10698-P-A (P) WCAP-10750-A	SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill, August 1987
	WCAP-14171 (P) WCAP-14172	WCOBRA/TRAC Applicability to AP600 Large-Break Loss-of-Coolant Accident, Revision 2, March 1998

(P) Denotes Document is Proprietary

1.7 Drawings and Other Detailed Information

1.7.1 Electrical and Instrumentation and Control Drawings

Instrument and control functional diagrams, electrical one-line diagrams, and onsite standby diesel generator loading sequence and initiating circuit logic diagrams are listed in Table 1.7-1.

The legend for electrical power, control, lighting, and communication drawings are provided in Figure 1.7-1, sheets 1, 2, and 3. The index, notes, and symbols for instrument and control functional diagrams are provided in Figure 7.1-1.

1.7.2 Piping and Instrumentation Diagrams

Table 1.7-2 contains a list of piping and instrumentation diagrams (P&IDs) and the corresponding DCD figure numbers. The three letter system names are provided in Table 1.7-2. Figures appear at the end of the respective text section. The P&ID legend, Figure 1.7-2, sheets 1, 2, and 3, provides an explanation of AP1000 symbols and characters used in these DCD figures.

1.7.3 Combined License Information

This section has no requirement for additional information to be provided in support of the combined license application.

Table 1.7-1

I&C FUNCTIONAL AND ELECTRICAL ONE-LINE DIAGRAMS

DCD Figure Number	Title
7.2-1 (Sheet 1)	Index and Symbols
7.2-1 (Sheet 2)	Reactor Trip Function
7.2-1 (Sheet 3)	Nuclear Startup Protection
7.2-1 (Sheet 4)	Nuclear Overpower Protection
7.2-1 (Sheet 5)	Core Heat Removal Protection
7.2-1 (Sheet 6)	Primary Overpressure Loss of Heat Sink Protection
7.2-1 (Sheet 7)	Loss of Heat Sink Protection
7.2-1 (Sheet 8)	Loss of Heat Sink Protection
7.2-1 (Sheet 9)	Steam Line Isolation
7.2-1 (Sheet 10)	Feedwater Isolation
7.2-1 (Sheet 11)	Safeguards Isolation
7.2-1 (Sheet 12)	Core Makeup Tank Actuation and Reactor Coolant Pump Trip
7.2-1 (Sheet 13)	Containment and Other Protection
7.2-1 (Sheet 14)	Turbine Related Protection
7.2-1 (Sheet 15)	Automatic Reactor Coolant System Overpressurization Valve Sequencing
7.2-1 (Sheet 16)	Incontainment Refueling Water Storage Tank Actuations
7.2-1 (Sheet 17)	Passive Residual Heat Removal and Core Makeup Tank Isolation Valve Interlocks
7.2-1 (Sheet 18)	Normal Residual Heat Removal System Isolation Valve Interlocks
7.2-1 (Sheet 19)	Diverse Actuation System Logic, Automatic Actuations
7.2-1 (Sheet 20)	Diverse Actuation System Logic, Manual Actuations
8.3.1-1	AC Power System - Station One-Line Diagram (Sheets 1 & 2)
8.3.1-2	On-site Standby Diesel Generator Initiation Circuit Logic Diagram
8.3.1-3	Post 72 Hours Temporary Electric Power One Line Diagram
8.3.2-1	Class 1E DC System One-Line Diagrams (Sheets 1 & 2)
8.3.2-2	Class 1E 208Y/120V UPS Power One-Line Diagram
8.3.2-3	Non-Class 1E DC & UPS System One-Line Diagrams (Sheets 1 & 2)

Table 1.7-2 (Sheet 1 of 3)

AP1000 SYSTEM DESIGNATORS AND SYSTEM DIAGRAMS

Designator	System (Note 1)	DCD Section	DCD Figure (Note 2)
ASS	Auxiliary Steam Supply System	10.4.10	None
BDS	Steam Generator Blowdown System	10.4.8	10.4.8-1
CAS	Compressed and Instrument Air Systems	9.3.1	9.3.1-1
CCS	Component Cooling Water System	9.2.2	9.2.2-2
CDS	Condensate System	10.4.7	10.4.7-1
CES	Condenser Tube Cleaning System	10.4.1.2.1, 10.4.5.2.3	None
CFS	Turbine Island Chemical Feed System	10.4.11	None
CMS	Condenser Air Removal System	10.4.2	None
CNS	Containment System	6.2.3	None
CPS	Condensate Polishing System	10.4.6	10.4.6-1
CVS	Chemical and Volume Control System	9.3.6	9.3.6-1
CWS	Circulating Water System (Partially out of scope)	10.4.5	None
DAS	Diverse Actuation System	7.7	7.2-1 (Sh. 19 & 20)
DDS	Data Display and Processing System	7.1 & 7.7	7.1-1
DOS	Standby Diesel and Auxillary Boiler Fuel Oil System	9.5.4	9.5.4-1
DRS	Storm Drain System (Wholly out of scope)	None	None
DTS	Demineralized Water Treatment System	9.2.3	None
DWS	Demineralized Water Transfer and Storage System	9.2.4	9.2.4-1
ECS	Main ac Power System	8.3.1	8.3.1-1
EDS	Non Class 1E dc and UPS System	8.3.2	8.3.2-3
EFS	Communication Systems	9.5.2	None
EGS	Grounding and Lightning Protection System	8.3.1.1	None
EHS	Special Process Heat Tracing System	8.3.1.1	None
ELS	Plant Lighting System	9.5.3	None
EQS	Cathodic Protection System (Partially out of scope)	None	None
FHS	Fuel Handling and Refueling System	9.1.1, 9.1.2, 9.1.4	9.1 - various
FPS	Fire Protection System	9.5.1, 6.5.2	9.5.1-1
FWS	Main and Startup Feedwater System	10.4.7, 10.4.9	10.4.7-1
GSS	Gland Seal System	10.4.3	10.4.3-1
HCS	Generator Hydrogen and CO_2 Systems	10.2	None
HDS	Heater Drain System	10.4.7	None
HSS	Hydrogen Seal Oil System	10.2	None
IDS	Class 1E dc and UPS System	8.3.2	8.3.2-1
IIS	In-core Instrumentation System	4.4.6	None

Table 1.7-2 (Sheet 2 of 3)

AP1000 SYSTEM DESIGNATORS AND SYSTEM DIAGRAMS

Designator	System (Note 1)	DCD Section	DCD Figure (Note 2)
LOS	Main Turbine and Generator Lube Oil System	10.2	None
MES	Meteorological and Environmental Monitoring System (Wholly out of scope)	2.3.3	None
MHS	Mechanical Handling System	9.1	None
MSS	Main Steam System	10.3	10.3.2-2
MTS	Main Turbine System	10.2	10.2-1
OCS	Operation and Control Centers System	7.1, Ch. 18	7.1-1
PCS	Passive Containment Cooling System	6.2.2	6.2.2-1
PGS	Plant Gas Systems	9.3.2	None
PLS	Plant Control System	7.1 & 7.7	7.1-1
PMS	Protection and Safety Monitoring System	Ch. 7	7.2-1
PSS	Primary Sampling System	9.3.3	9.3.3-1
PWS	Potable Water System	9.2.5	None
PXS	Passive Core Cooling System	6.3	6.3-1
RCS	Reactor Coolant System	5.1	5.1-5
RDS	Gravity and Roof Drain Collection System (Partially out of scope)	None	None
RMS	Radiation Monitoring System	11.5	None
RNS	Normal Residual Heat Removal System	5.4.7	5.4-7
RWS	Raw Water System (Wholly out of scope)	9.2.1.2.2, 9.2.1.2.3.1, 9.2.3, 9.2.5	None
RXS	Reactor System	3.9.4, 3.9.5, 4.2.2.2, 4.2.2.3.1, 5.3	5.3-1
SDS	Sanitary Drainage System (Partially out of scope)	9.2.6	None
SES	Plant Security System (Partially out of scope)	13.6	None
SFS	Spent Fuel Pit Cooling System	9.1.3	9.1-6
SGS	Steam Generator System	10.3, 10.4.7, 10.4.9	10.3.2-1
SJS	Seismic Monitoring System	3.7.4	None
SMS	Special Monitoring System	4.4.6.4	None
SSS	Secondary Sampling System	9.3.4	None
SWS	Service Water System	9.2.1	9.2.1-1
TCS	Turbine Building Closed Cooling Water System	9.2.8	None

Table 1.7-2 (Sheet 3 of 3)

AP1000 SYSTEM DESIGNATORS AND SYSTEM DIAGRAMS

Designator	System (Note 1)	DCD Section	DCD Figure (Note 2)
TDS	Turbine Island Vents, Drains and Relief System	9.2.9.2.2, 10.4.2.2.1, 10.4.3.1.2, 10.4.3.2.2, 10.4.6.3	None
TOS	Main Turbine Control and Diagnostics System	10.2.2.4	None
TVS	Closed Circuit TV System (Wholly out of scope)	None	None
VAS	Radiologically Controlled Area Ventilation System	9.4.3	9.4.3-1
VBS	Nuclear Island Nonradioactive Ventilation System	9.4.1	9.4.1-1
VCS	Containment Recirculation Cooling System	9.4.6	9.4.6-1
VES	Main Control Room Emergency Habitability System	6.4	6.4-2
VFS	Containment Air Filtration System	9.4.7	9.4.7-1
VHS	Health Physics and Hot Machine Shop HVAC System	9.4.11	9.4.11-1
VLS	Containment Hydrogen Control System	6.2.4	6.2.4 - various
VRS	Radwaste Building HVAC System	9.4.8	9.4.8-1
VTS	Turbine Building Ventilation System	9.4.9	9.4.9-1
VUS	Containment Leak Rate Test System	6.2.5	6.2.5-1
VWS	Central Chilled Water System	9.2.7	9.2.7-1
VXS	Annex/Auxiliary Non-Radioactive Ventilation System	9.4.2	9.4.2-1
VYS	Hot Water Heating System	9.2.10	None
VZS	Diesel Generator Building Ventilation System	9.4.10	9.4.10-1
WGS	Gaseous Radwaste System	11.3	11.3-2
WLS	Liquid Radwaste System	11.2	11.2-2
WRS	Radioactive Waste Drain System	9.3.5, 11.2	9.3.5-1
WSS	Solid Radwaste System	11.4	11.4-1
WWS	Waste Water System	9.2.9	None
ZAS	Main Generation System (Note 3)	8.1	None
ZBS	Transmission Switchyard and Offsite Power System (Wholly out of scope)	8.2	None
ZOS	Onsite Standby Power System	8.2.1, 8.3.1	8.3.1-4, 8.3.1-5
ZVS	Excitation and Voltage Regulation System	10.2.2.3	None

Notes:

1. For the System names:
   a) An entry with the system name only means the system is wholly in the scope of the AP1000 design certification.
   b) An entry with the system name followed by (Partially out of scope) means the system is partially in the scope of the AP1000 design certification.
   c) An entry with the system name followed by (Wholly out of scope) means the system is not in the scope of the AP1000 design certification.

2. For the DCD Figures:
   In the AP1000 design documentation system, Piping and Instrumentation Diagrams are numbered xxx-M6-yyy, where xxx is the system designator and yyy is the sheet number. Electrical One-Line Diagrams are numbered xxx-E3-yyy, where xxx is the system designator and yyy is the sheet number. I&C Functional Logic Diagrams are numbered xxx-J1-yyy, where xxx is the I&C system designator and yyy is the sheet number.

3. For the Main Generation System:
   The high side voltage of the main step-up transformer and the reserve auxiliary transformer is site specific.

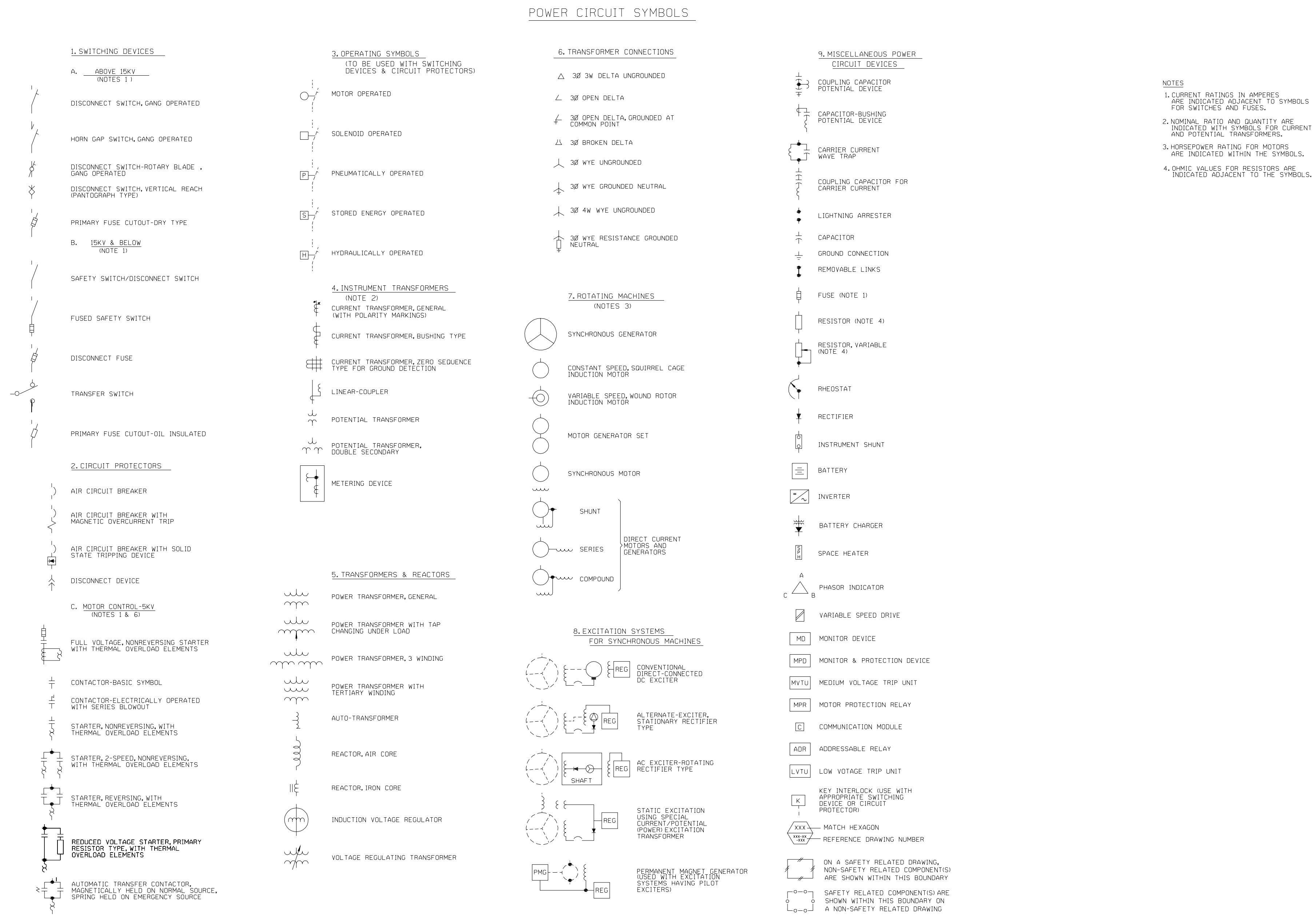


Figure 1.7-1 (Sheet 1 of 3)

Legend for Electrical Power, Lighting, and Communication Drawings

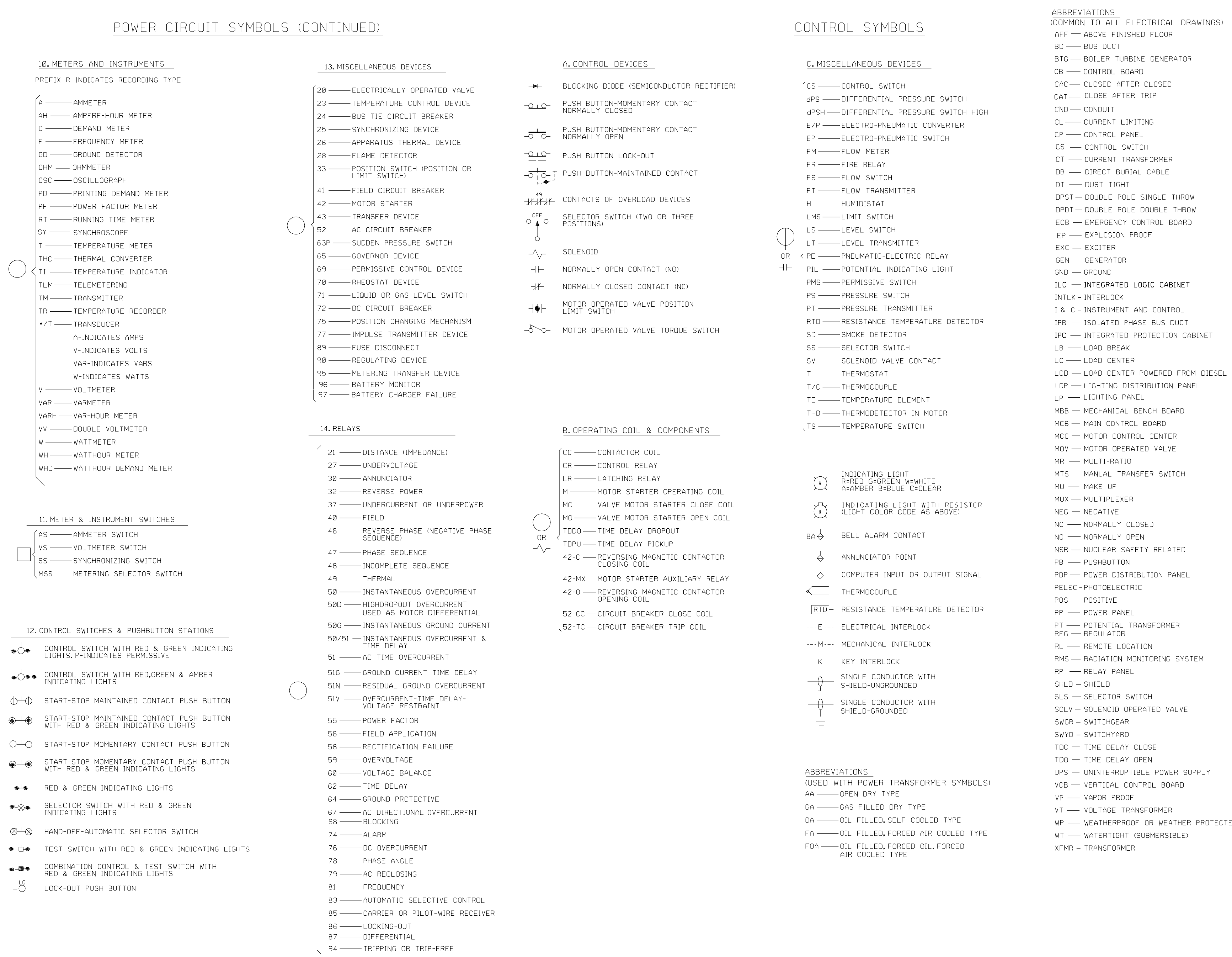


Figure 1.7-1 (Sheet 2 of 3)

Legend for Electrical Power, Lighting, and Communication Drawings

Figure 1.7-1 (Sheet 3 of 3)

Legend for Electrical Power, Lighting, and Communication Drawings

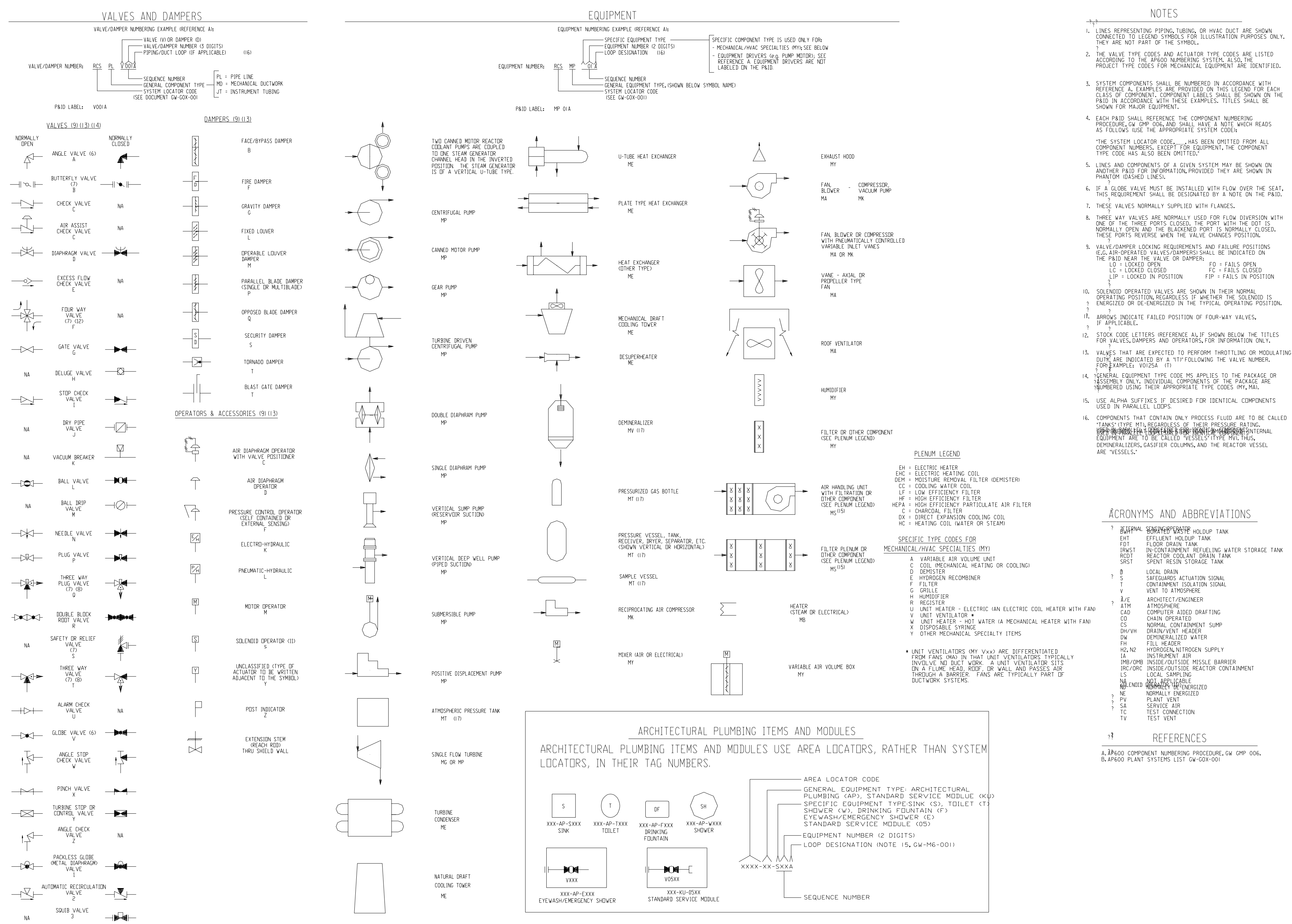
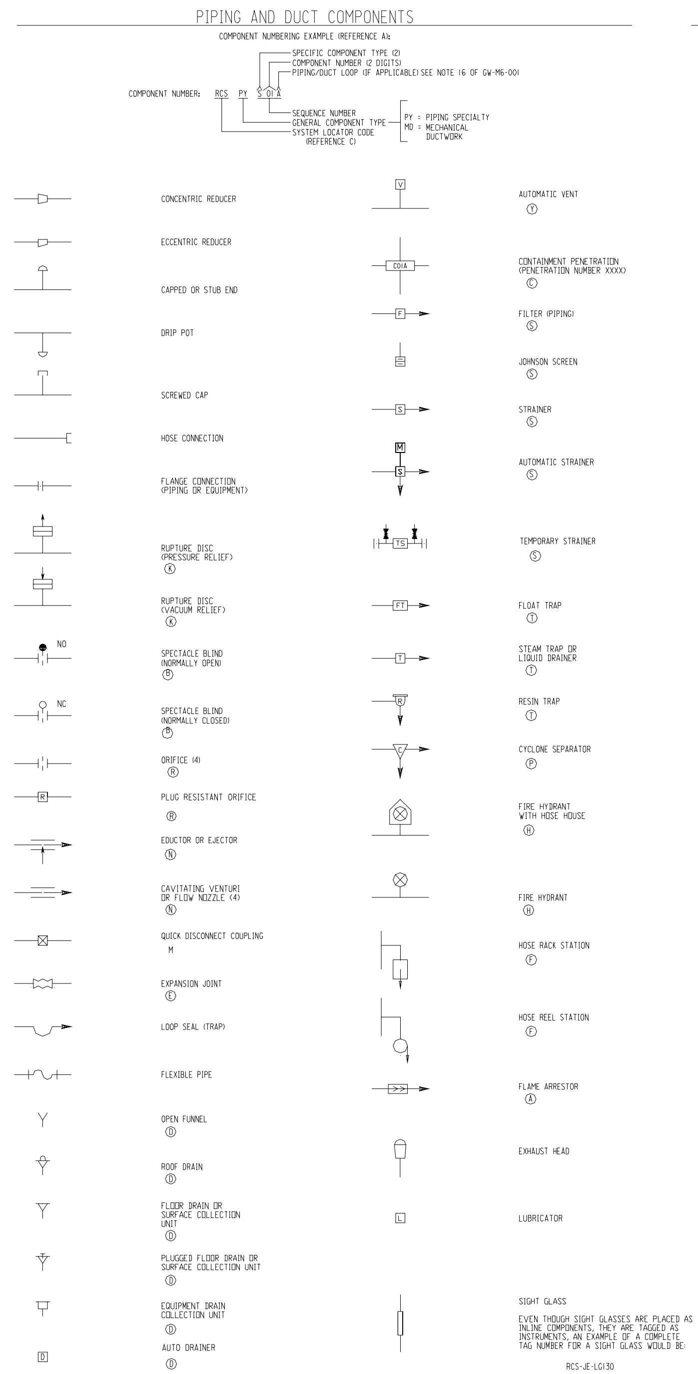
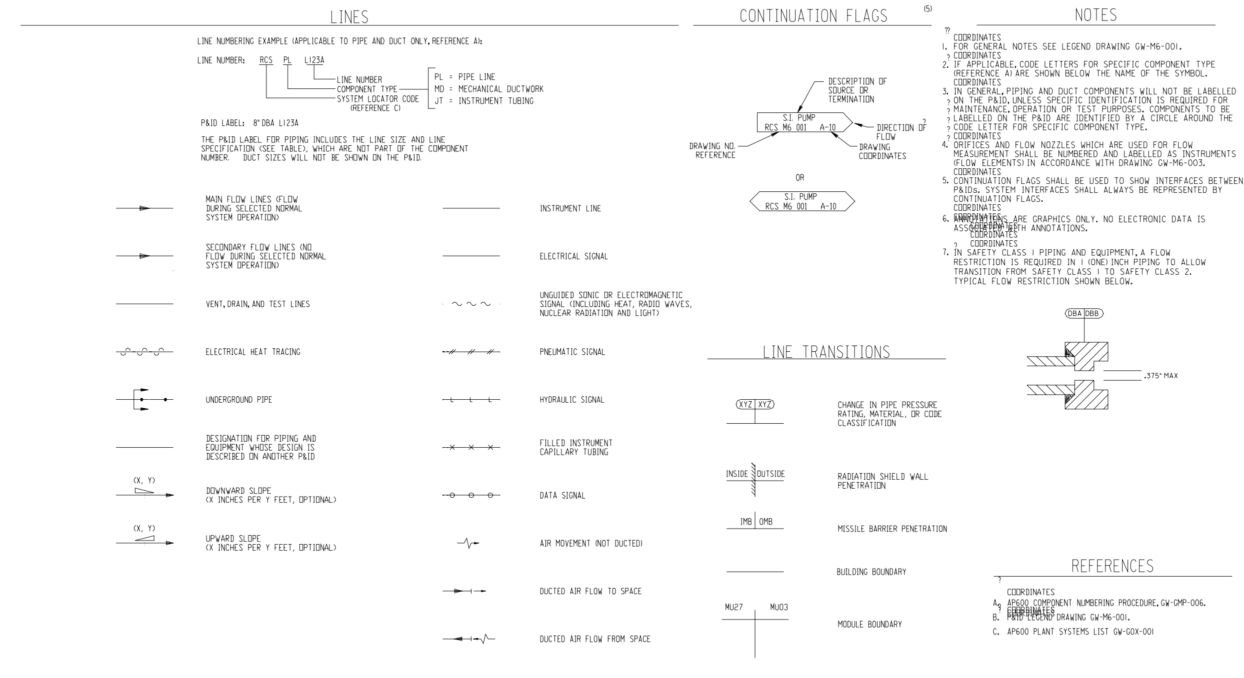


Figure 1.7-2 (Sheet 1 of 3)

Piping and Instrumentation Diagram Legend





LINE AND VALVE/DAMPER SPECIFICATIONS

CODE	PRESSURE RATING (FIRST LETTER)	MATERIAL (SECOND LETTER)	DESIGN CODE (THIRD LETTER)
A	2500# NORMAL	ALLOY STEEL, STANDARD	ASME SEC. III, CLASS 1, NRC QUAL GRP A
B	2038# (RCS CONDITIONS)	AUSTENITIC STAINLESS STEEL, STANDARD	ASME SEC. III, CLASS 2, NRC QUAL GRP B
C	1500# NORMAL	CARBON STEEL, STANDARD	ASME SEC. III, CLASS 3, NRC QUAL GRP C
D	900# NORMAL	DUCTILE IRON	ANSI B31.1, NRC QUAL GRP D
E	600# /900# NORMAL		ANSI B31.1, NON - Q
F	400# NORMAL	FERROUS, CAST IRON	NATIONAL FIRE PROTECTION ASSOCIATION CODE, FIRE PROTECTION QA
G	300# NORMAL	CARBON STEEL, GALVANIZED	NATIONAL FIRE PROTECTION ASSOCIATION CODE
H	250# NORMAL		
J	150# NORMAL		
K	125# NORMAL	COPPER, BRASS OR BRONZE	
L		LINED PIPE	SMACNA DUCT CONSTRUCTION STANDARD
M		ALUMINUM	
N			
P		PLASTIC AND NON-METALLIC	NATIONAL PLUMBING CODE
Q			
R	175# UL LISTED OR FM-APPROVED	CONCRETE	ASME N509 DUCT STANDARD
S	200# UL LISTED OR FM-APPROVED	ALLOY STEEL, HIGH STRENGTH	
T		AUSTENITIC STAINLESS STEEL, HIGH STRENGTH	
U	0" - 2" W.G. DUCT PER SMACNA	CARBON STEEL, IMPACT TESTED	
V	2" - 6" W.G. DUCT PER SMACNA		
W	6" - 10" W.G. DUCT PER SMACNA		AMERICAN WATER WORKS ASSOCIATION STANDARD
X	10" W.G. & LARGER DUCT PER SMACNA		
Y	SPECIAL USE AS SHOWN ON PIPING CLASS SHEETS	SPECIAL USE AS SHOWN ON PIPING CLASS SHEETS	SPECIAL USE AS SHOWN ON PIPING CLASS SHEETS
Z	SPECIAL USE AS SHOWN ON PIPING CLASS SHEETS	SPECIAL USE AS SHOWN ON PIPING CLASS SHEETS	SPECIAL USE AS SHOWN ON PIPING CLASS SHEETS

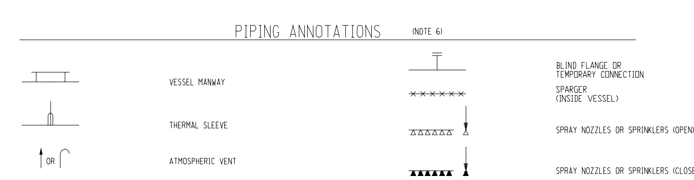


Figure 1.7-2 (Sheet 2 of 3)

Piping and Instrumentation Diagram Legend

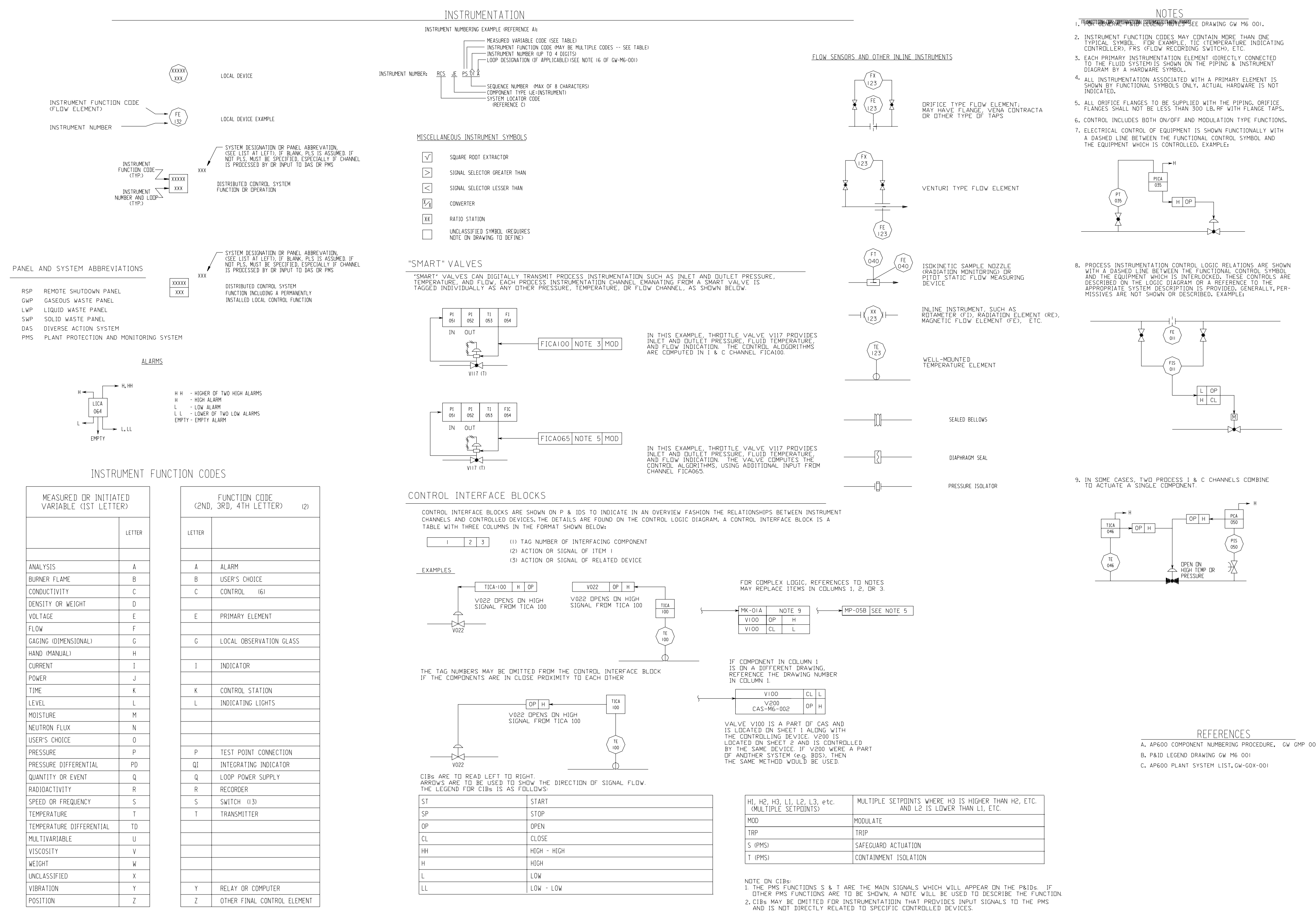


Figure 1.7-2 (Sheet 3 of 3)

Piping and Instrumentation Diagram Legend

1.8 Interfaces for Standard Design

This section identifies the AP1000 standard plant scope, interfaces related to design certification between the AP1000 plant design and the Combined License applicant, and the site-specific items to be included in an application for a Combined License. It is submitted to satisfy the requirements of 10 CFR 52.47(a)(1)(vii).

The AP1000 is a plant design incorporating six buildings, the equipment in them and the associated yard structures and tankage. This includes the entire nuclear island (consisting of the containment/shield building and the auxiliary building), the annex building and associated equipment, the diesel/generator building and associated equipment, the turbine generator building, the turbine/generator equipment and the radwaste facilities. The physical boundary of the portion of the AP1000 design included in this application for Design Certification is shown on the site plan, Figure 1.2-2. It includes arrangement and placement of structures within the indicated boundary including the vehicle barriers necessary for security, but not the boundary fence. As a result, no interfaces need to be identified between or among the portions of the plant within the boundary. They are addressed in their appropriate section of this DCD. There are no safety-related interfaces to site-specific elements of the plant outside the scope of this certification application. Unless otherwise noted, the following site-specific elements are outside the scope of the AP1000 standard plant:

(1) The portions of the circulating water system and its heat sink outside the AP1000 buildings, as well as the specific design details of the main condenser. A conceptual design is presented, delineated by Double Brackets ([[ ]]), in subsection 10.4.5, based upon a cooling tower approach.

(2) The offsite power transmission system outside the low voltage terminals of the main and reserve transformers. Location and design of the main switchyard area and the equipment located therein, as well as design details such as voltage level for the main step-up transformers. A conceptual design of this system is included, delineated by Double Brackets ([[ ]]), in Section 8.2 for reference.

(3) Raw water source and treatment outside the turbine building. An interface specification of amount and water chemistry limits is provided.

(4) Sanitary and other drain systems outside the buildings identified above. This DCD is based upon the COL applicant providing adequate overall site drain collection and processing systems

(5) Communications systems and equipment outside the buildings identified above. This DCD is based upon the COL applicant providing adequate external communications.

(6) Location and design of administrative and training structures.

(7) Landscaping features.

A more detailed listing of the systems included in the standard AP1000 plant is included in Section 3.2.

There are a number of information interfaces between the AP1000 design and other portions of a completely licensed facility which must be addressed by parties that reference the AP1000 design. These interfaces are identified in Table 1.8-1 in the order they are presented in this DCD.

The safety-related interface requirements in Table 1.8-1 have been selected based on a review of interfaces between the AP1000 plant design and other Combined License applicant or site-specific items. Satisfying the referenced information for each of the interfaces listed will provide confidence that systems, structures and components within the AP1000 can perform their safety functions. The specific details of the interface parameters are identified in the DCD sections identified in Table 1.8-1. The interface specifications have been selected to suit a wide range of potential sites. Values identified by a Combined License applicant to be outside the range of acceptable parameters may be demonstrated to be acceptable. Such cases will be documented in the appropriate sections of the specific Combined License application.

The classification of interface types is based on the sources of interfaces listed in Appendix A of Regulatory Guide 1.70. The first four types below are directly related to the four sources of interfaces. They have been redefined slightly to reflect the fact that AP1000 is an essentially complete plant design. The classification of interface types is as follows:

- **Requirement of AP1000** – Requirements for operation of the AP1000 design that must be satisfied by the matching portion of the site, utility or Combined License applicant administration.

- **AP1000 Interface** – Interface condition used for AP1000 design which must be more precisely defined during the coordination effort between the AP1000 design team and the Combined License applicant.

- **Site Interface** – Site-related interface data upon which the AP1000 design is based.

- **Pertinent Criteria** – Criteria pertinent to the AP1000 design that may be useful for the design and staff review of the matching systems, components and structures.

- **Not an Interface** – Interface items identified in Appendix A of Regulatory Guide 1.70 which are wholly within the boundaries of the AP1000 plant. As a result, the "Matching Interface Item" in Table 1.8-1 is identified as N/A (not applicable).

- **Non-Nuclear Safety (NNS)** – Interface items identified in Appendix A of Regulatory Guide 1.70 which are non-nuclear safety-related because of the design features of AP1000.

Note that all plant interfaces listed in Appendix A of Regulatory Guide 1.70 have been listed in Table 1.8-1. As noted above and in Table 1.8-1, a number of these interfaces do not apply to the AP1000 plant as described in this DCD. In some cases, the interface listed in Appendix A of Regulatory Guide 1.70 is totally within the AP1000 plant and therefore not an interface. Other interfaces from Appendix A of Regulatory Guide 1.70 are identified as non-nuclear safety. The classification of systems, structures and components is described in Section 3.2. Only safety-related interfaces are detailed in Table 1-8.1. An example of an "NNS" (non-nuclear safety) type of interface is any of those associated with site service water. AP1000 does not rely on site service water as a safety grade ultimate heat sink. Neither the cooling tower nor the diesel-generator building is safety-related in AP1000. As such, there are no safety-related interfaces for these features.

Interfaces are listed in the order discussed in the DCD. General interfaces are listed as they relate to a particular section of this DCD. No specific system-by-system interface listings are required due to the complete nature of the AP1000 plant design. All safety-related systems are contained within the AP1000 plant design. The listing includes identification of the interface classification and the matching interface item to be specified by the Combined License applicant. In addition, the section of this DCD which addresses the listed interface is identified. To satisfy the requirements of 10 CFR 52.47(a)(1)(ix), representative conceptual designs are included in this DCD for those portions of the plant for which Westinghouse does not seek certification to aid the NRC staff in its review of the DCD and the probabilistic risk assessment to be submitted in support of the application, and to permit assessment of the adequacy of interface requirements.

Combined License Information

Combined License applicants referencing the AP1000 certified design will be required to provide site-specific information, verification that interface criteria are satisfied, information related to operating procedures, and other information required to support the AP1000 Design Certification. The description of information to be provided by the Combined License applicant is found in the DCD sections applicable to the specific information. Table 1.8-2 is a listing of the Combined License information items and the DCD location of the description of the information.

Table 1.8-1 (Sheet 1 of 7)

SUMMARY OF AP1000 PLANT INTERFACES WITH REMAINDER OF PLANT

Item No.	Interface	Interface Type	Matching Interface Item	Section or Sub-section
1.1	Post accident Radio-Iodine sampling capability per NUREG 0737	Requirement of AP1000	Combined License applicant program	1.9.3
2.1	Envelope of AP1000 plant site related parameters	Site Interface	Site specific parameters	2.0
2.2	External missiles from man-made hazards and accidents	Site Interface	Site specific parameters	2.2
2.3	Maximum loads from man-made hazards and accidents	Site Interface	Site specific parameters	2.2
2.4	Limiting meteorological parameters (χ/Q) for design basis accidents and for routine releases and other extreme meteorological conditions for the design of systems and components exposed to the environment.	Site Interface	Site specific parameters	2.3
2.5	Tornado and operating basis wind loadings	Site Interface	Site specific parameters	2.3
2.6	External missiles generated by natural phenomena	Site Interface	Site specific parameters	2.3
2.7	Snow, ice and rain loads	Site Interface	Site specific parameters	2.3
2.8	Ambient air temperatures	Site Interface	Site specific parameters	2.3
2.9	Onsite meteorological measurement program	Requirement of AP1000	Combined License applicant program	2.3.3
2.10	Flood and ground water elevations	Site Interface	Site specific parameters	2.4
2.11	Hydrostatic loads on systems, components and structures	Site Interface	Site specific parameters	2.4
2.12	Seismic parameters peak ground acceleration response spectra shear wave velocity	Site Interface	Site specific parameters	 2.5 2.5 2.5

Table 1.8-1 (Sheet 2 of 7)

SUMMARY OF AP1000 PLANT INTERFACES WITH REMAINDER OF PLANT

Item No.	Interface	Interface Type	Matching Interface Item	Section or Sub-section
2.13	Required bearing capacity of foundation materials	Site Interface	Site specific parameters	2.5
3.1	Deleted			
3.2	Operating procedures to minimize water hammer	Requirement of AP1000	Combined License applicant procedure	3.6, 10
3.3	Site seismic sensor location and "trigger" value	Requirement of AP1000	Onsite implementation	3.7.4
3.4	Depth of overburden	Requirement of AP1000	Onsite implementation	3.8
3.5	Depth of embedment	Requirement of AP1000	Onsite implementation	3.8
3.6	Specific depth of waterproofing	Requirement of AP1000	Onsite implementation	3.8.5
3.7	Foundation Settlement Monitoring	Requirement of AP1000	Combined License applicant coordination	3.8.5
3.8	Lateral earth pressure loads	Not an Interface	N/A	3
3.9	Preoperational piping vibration test parameters	Not an Interface	N/A	3
3.10	Inservice Inspection requirements and locations	Requirement of AP1000	Combined License applicant program	3.9.6 5.2.4 6.6
3.11	Maintenance of preservice and reference test data for inservice testing of pumps and valves	Requirement of AP1000	Combined License applicant program	3.9.6 5.2.4 6.6
3.12	Earthquake response procedures	Requirement of AP1000	Combined License applicant program	3.7.4
5.1	Steam Generator Tube Surveillance Requirements	Requirement of AP1000	Combined License applicant program	5.4.2

Table 1.8-1 (Sheet 3 of 7)

SUMMARY OF AP1000 PLANT INTERFACES WITH REMAINDER OF PLANT

Item No.	Interface	Interface Type	Matching Interface Item	Section or Sub-section
6.1	Inservice Inspection requirements for the containment	Requirement of AP1000	Combined License applicant program	6.2.1
6.2	Off site environmental conditions assumed for Main Control Room and technical support center habitability design	AP1000 Interface	Site specific parameter	6.4
7.1	Listing of all design criteria applied to the design of the I&C systems	Not an Interface	N/A	7
7.2	Power required for site service water instrumentation	NNS and Not an Interface	N/A	7
7.3	Other provisions for site service water instrumentation	NNS and Not an Interface	N/A	7
8.1	Listing of design criteria applied to the design of the offsite power system	NNS	Combined License applicant coordination	8
8.2	Offsite ac requirements Steady-state load Inrush kVA for motors Nominal voltage Allowable voltage regulation Nominal frequency Allowable frequency fluctuation Maximum frequency decay rate Limiting under frequency value for RCP	NNS	Combined License applicant coordination	8

Table 1.8-1 (Sheet 4 of 7)

SUMMARY OF AP1000 PLANT INTERFACES WITH REMAINDER OF PLANT

Item No.	Interface	Interface Type	Matching Interface Item	Section or Sub-section
8.3	Offsite transmission system analysis: Loss of AP1000 or largest unit Voltage operating range Transient stability must be maintained and the RCP bus voltage must remain above the voltage required to maintain the flow assumed in Chapter 15 analyses for a minimum of three (3) seconds following a turbine trip. The protective devices controlling the switchyard breakers are set with consideration given to preserving the plant grid connection following a turbine trip.	NNS	Combined License applicant analysis	8.2
8.4	Listing of design criteria applied to the design of onsite ac power systems	NNS and Not an Interface	N/A	8
8.5	Onsite ac requirements	NNS and Not an Interface	N/A	8
8.6	Diesel generator room coordination	NNS and Not an Interface	N/A	8
8.7	Listing of design criteria applied to the design of onsite dc power systems	Not an Interface	N/A	8
8.8	Provisions of dc power systems to accommodate the site service water system	NNS and Not an Interface	N/A	8
9.1	Listing of design criteria applied to the design of portions of the site service water within AP1000	NNS and Not an Interface	N/A	9
9.2	Integrated heat load to site service water system	NNS and Not an Interface	N/A	9
9.3	Plant cooling water systems parameters	NNS and Not an Interface	N/A	9

Table 1.8-1 (Sheet 5 of 7)

SUMMARY OF AP1000 PLANT INTERFACES WITH REMAINDER OF PLANT

Item No.	Interface	Interface Type	Matching Interface Item	Section or Sub-section
9.4	Plant makeup water quality limits	NNS	Site specific parameter	9
9.5	Requirements for location and arrangement of raw and sanitary water systems	NNS	Site implementation	9
9.6	Ventilation requirements for diesel-generator room	NNS and Not an Interface	N/A	9
9.7	Requirements to satisfy fire protection program	AP1000 Interface	Combined License applicant program	9.5.1
11.1	Expected release rates of radioactive material from the Liquid Waste System including: Location of release points Effluent temperature Effluent flow rate Size and shape of flow orifices	Site Interface	Site specific parameters	11.2
11.2	Expected release rates of radioactive materials from the Gaseous Waste System including: Location of release points Height above grade Height relative to adjacent buildings Effluent temperature Effluent flow rate Effluent velocity Size and shape of flow orifices	Site Interface	Site specific parameters	11.3

Table 1.8-1 (Sheet 6 of 7)

SUMMARY OF AP1000 PLANT INTERFACES WITH REMAINDER OF PLANT

Item No.	Interface	Interface Type	Matching Interface Item	Section or Sub-section
11.3	Expected release rates of radioactive material from the Solid Waste System including: Location of release points Material types Material qualities Size and shape of material containers	Site Interface	Site specific parameters	11.4
11.4	Requirements for offsite sampling and monitoring of effluent concentrations	AP1000 Interface	Combined License applicant program	11.5
12.1	Identification of miscellaneous radioactive sources	AP1000 Interface	Combined License applicant program	12.2
13.1	Features that may affect plans for coping with emergencies as specified in 10 CFR 50, Appendix O	AP1000 Interface	Combined License applicant program	13.3
13.2	Physical Security Plan consistent with AP1000 plant	AP1000 Interface	Combined License applicant program	13.6
14.1	Identification of special features to be considered in development of the initial test program	Requirement of AP1000	Combined License applicant program	14
14.2	Maintenance of preoperational test data and inservice inspection baseline data	AP1000 Interface	Combined License applicant program	14
16.1	Administrative requirements associated with reliability information maintenance	AP1000 Interface	Combined License applicant program	16
16.2	Administrative requirements associated with the Technical Specifications	Requirement of AP1000	Combined License applicant implementation	16
16.3	Site and operator related information associated with the Reliability Assurance Program (D-RAP)	Requirement of AP1000	Combined License applicant program	16.2
18.1	Operating staff consistent with Human Factors evaluations	AP1000 Interface	Combined License applicant program	18.6
18.2	Operator training consistent with Human Factors evaluations	AP1000 Interface	Combined License applicant program	18.8 18.10

Table 1.8-1 (Sheet 7 of 7)

SUMMARY OF AP1000 PLANT INTERFACES WITH REMAINDER OF PLANT

Item No.	Interface	Interface Type	Matching Interface Item	Section or Sub-section
18.3	Operating Procedures consistent with Human Factors evaluations	AP1000 Interface	Combined License applicant program	18.8 18.10
18.4	Final coordination and integration of human system interface areas within a specific AP1000 consistent with Human Factors evaluations	AP1000 Interface	Combined License applicant program	18.2 18.8
18.5	Final coordination and integration of Combined License applicant facilities with those of a specific AP1000 consistent with Human Factors evaluations	AP1000 Interface	Combined License applicant program	18.2 18.8

Table 1.8-2 (Sheet 1 of 7)

SUMMARY OF AP1000 STANDARD PLANT COMBINED LICENSE INFORMATION ITEMS

Item No.	Subject	Subsection
1.1-1	Construction and Startup Schedule	1.1.7
2.1-1	Geography and Demography	2.1.1
2.2-1	Identification of Site-specific Potential Hazards	2.2.1
2.3-1	Regional Climatology	2.3.6.1
2.3-2	Local Meteorology	2.3.6.2
2.3-3	Onsite Meteorological Measurements Program	2.3.6.3
2.3-4	Short-Term Diffusion Estimates	2.3.6.4
2.3-5	Long-Term Diffusion Estimates	2.3.6.5
2.4-1	Hydrological Description	2.4.1.1
2.4-2	Floods	2.4.1.2
2.4-3	Cooling Water Supply	2.4.1.3
2.4-4	Groundwater	2.4.1.4
2.4-5	Accidental Release of Liquid Effluents into Ground and Surface Water	2.4.1.5
2.4-6	Flood Protection Emergency Operation Procedures	2.4.1.6
2.5-1	Basic Geologic and Seismic Information	2.5.1
2.5-2	Site Seismic and Tectonic Characteristics Information	2.5.2.1
2.5-3	Geoscience Parameters	2.5.2.3
2.5-4	Surface Faulting	2.5.3
2.5-5	Site and Structures	2.5.4.5.1
2.5-6	Properties of Underlying Materials	2.5.4.5.2
2.5-7	Excavation and Backfill	2.5.4.5.3
2.5-8	Ground Water Conditions	2.5.4.5.4
2.5-9	Liquefaction Potential	2.5.4.5.5
2.5-10	Bearing Capacity	2.5.4.5.6
2.5-11	Earth Pressures	2.5.4.5.7
2.5-12	Static and Dynamic Stability of Facilities	2.5.4.5.9

Table 1.8-2 (Sheet 2 of 7)

SUMMARY OF AP1000 STANDARD PLANT COMBINED LICENSE INFORMATION ITEMS

Item No.	Subject	Subsection
2.5-13	Subsurface Instrumentation	2.5.4.5.10
2.5-14	Stability of Slopes	2.5.5
2.5-15	Embankments and Dams	2.5.6
3.3-1	Wind and Tornado Site Interface Criteria	3.3.3
3.4-1	Site-Specific Flooding Hazards Protective Measures	3.4.3
3.5-1	External Missile Protection Requirements	3.5.4
3.6-1	Pipe Break Hazards Analysis	3.6.4.1
3.6-2	Leak-Before-Break Evaluation of as-Designed Piping	3.6.4.2
3.6.3	Leak-Before-Break Evaluation of as-Built Piping	3.6.4.3
3.6-4	Primary System Inspection Program for Leak-Before-Break Piping	3.6.4.4
3.7-1	Seismic Analysis of Dams	3.7.5.1
3.7-2	Post-Earthquake Procedures	3.7.5.2
3.7-3	Seismic Interaction Review	3.7.5.3
3.7-4	Reconciliation of Seismic Analyses of Nuclear Island Structures	3.7.5.4
3.7-5	Location of Free-Field Acceleration Sensor	3.7.5.5
3.8-1	Containment Vessel Design Adjacent to Large Penetrations	3.8.6.1
3.8-2	Passive Containment Cooling System Water Storage Tank Examination	3.8.6.2
3.8-3	As-Built Summary Report	3.8.6.3
3.8.4	In-Service Inspection of Containment Vessel	3.8.6.4
3.9-1	Reactor Internal Vibration Response	3.9.8.1
3.9-2	Design Specification and Reports	3.9.8.2
3.9-3	Snubber Operability Testing	3.9.8.3
3.9-4	Valve Inservice Testing	3.9.8.4
3.9-5	Surge Line Thermal Monitoring	3.9.8.5
3.9-6	Piping Benchmark Program	3.9.8.6
3.10-1	Experience-Based Qualification	3.10.6
3.11-1	Equipment Qualification File	3.11.5

Table 1.8-2 (Sheet 3 of 7)

SUMMARY OF AP1000 STANDARD PLANT COMBINED LICENSE INFORMATION ITEMS

Item No.	Subject	Subsection
4.2-1	Changes to Reference Reactor Design	4.2.5
4.3-1	Changes to Reference Reactor Design	4.3.4
4.4-1	Changes to Reference Reactor Design	4.4.7
4.4-2	Confirm Assumptions for Safety Analyses DNBR Limits	4.4.7
5.2-1	ASME Code and Addenda	5.2.6.1
5.2-2	Plant Specific Inspection Program	5.2.6.2
5.3-1	Reactor Vessel Pressure – Temperature Limit Curves	5.3.6.1
5.3-2	Reactor Vessel Materials Surveillance Program	5.3.6.2
5.3-3	Surveillance Capsule Lead Factor and Azimuthal Location Confirmation	5.3.6.3
5.3-4	Reactor Vessel Materials Properties Verification	5.3.6.4
5.3-5	Reactor Vessel Insulation	5.3.6.5
5.4-1	Steam Generator Tube Integrity	5.4.15
6.1-1	Procedure Review for Austenitic Stainless Steels	6.1.3.1
6.1-2	Coating Program	6.1.3.2
6.2-1	Containment Leak Rate Testing	6.2.6
6.3-1	Containment Cleanliness Program	6.3.8.1
6.3-2	Verification of Containment Resident Particulate Debris Characteristics	6.3.8.2
6.4-1	Local Toxic Gas Services and Monitoring	6.4.7
6.4-2	Procedures for Training for Control Room Habitability	6.4.7
6.4-3	Main Control Room Inleakage Test Frequency	6.4.7
6.6-1	Inspection Programs	6.6.9.1
6.6-2	Construction Activities	6.6.9.2
7.1-1	Setpoint Calculations for Protective Functions	7.1.6
7.1-2	Resolution of Generic Open Items and Plant-Specific Action Items	7.1.6
7.2-1	FMEA for Protection System	7.2.3
8.2-1	Offsite Electrical Power	8.2.5
8.2-2	Technical Interfaces	8.2.5

Table 1.8-2 (Sheet 4 of 7)

SUMMARY OF AP1000 STANDARD PLANT COMBINED LICENSE INFORMATION ITEMS

Item No.	Subject	Subsection
8.3-1	Grounding and Lightning Protection	8.3.3
8.3-2	Onsite Electrical Power Plant Procedures	8.3.3
9.1-1	New Fuel Rack	9.1.6
9.1-2	Criticality Analysis for New Fuel Rack	9.1.6
9.1-3	Spent Fuel Racks	9.1.6
9.1-4	Criticality Analysis for Spent Fuel Racks	9.1.6
9.1-5	Inservice Inspection Program of Cranes	9.1.6
9.1-6	Radiation Monitor	9.1.6
9.3-1	Air Systems (NUREG-0933 Issue 43)	9.3.7
9.4-1	Ventilation Systems Operations	9.4.12
9.5-1	Qualification Requirements for Fire Protection Program	9.5.1.8
9.5-2	Fire Protection Analysis Information	9.5.1.8
9.5-3	Regulatory Conformance	9.5.1.8
9.5-4	NFPA Exceptions	9.5.1.8
9.5-5	Operator Actions Minimizing Spurious ADS Actuation	9.5.1.8
9.5-6	Verification of Field Installed Fire Barriers	9.5.1.8
9.5-7	Fire Resistance Test Data	9.5.1.8
9.5-8	Establishment of Procedures to Minimize Risk for Fire Areas Breached During Maintenance	9.5.1.8
9.5-9	Offsite Interfaces	9.5.2.5.1
9.5-10	Emergency Offsite Communications	9.5.2.5.2
9.5-11	Security Communications	9.5.2.5.3
9.5-12	Cathodic Protection	9.5.4.7
9.5-13	Fuel Degradation Protection	9.5.4.7
10.1-1	Erosion-Corrosion Monitoring	10.1.3
10.2-1	Turbine Maintenance and Inspection	10.2.6
10.4-1	Circulating Water Supply	10.4.12.1
10.4-2	Condensate, Feedwater and Auxiliary Steam System Chemistry Control	10.4.12.2

Table 1.8-2 (Sheet 5 of 7)

SUMMARY OF AP1000 STANDARD PLANT COMBINED LICENSE INFORMATION ITEMS

Item No.	Subject	Subsection
10.4-3	Potable Water	10.4.12.3
11.2-1	Liquid Radwaste Processing by Mobile Equipment	11.2.5.1
11.2-2	Cost Benefit Analysis of Population Doses	11.2.5.2
11.2-3	Identification of Ion Exchange and Adsorbent Media	11.2.5.3
11.2-4	Dilution and Control of Boric Acid Discharge	11.2.5.4
11.3-1	Cost Benefit Analysis of Population Doses	11.3.5.1
11.3-2	Identification of Adsorbent Media	11.3.5.2
11.4-1	Solid Waste Management System Process Control Program	11.4.6
11.5-1	Plant Offsite Dose Calculation Manual (ODCM)	11.5.7
11.5-2	Effluent Monitoring and Sampling	11.5.7
11.5-3	10 CFR 50, Appendix I	11.5.7
12.1-1	ALARA and Operational Policies	12.1.3
12.2-1	Additional Contained Radiation Sources	12.2.3
12.3-1	Administrative Controls for Radiological Protection	12.3.5
12.3-2	Criteria and Methods for Radiological Protection	12.3.5
12.5-1	Radiological Protection Organization and Procedures	12.5.5
13.1-1	Organizational Structure of Combined License Applicant	13.1.1
13.2-1	Training Program for Plant Personnel	13.2.1
13.3-1	Emergency Planning and Communications	13.3.1
13.3-2	Activation of Emergency Operations Facility	13.3.1
13.4-1	Operational Review	13.4.1
13.5-1	Plant Procedures	13.5.1
13.6-1	Security Plans, Organization and Testing	13.6.13.1
13.6-2	Vital Equipment Verification	13.6.13.2
13.6-3	Site-Specific Security System	13.6.13.3
13.6-4	Nuclear Material Control Requirements	13.6.13.4
14.4-1	Organization and Staffing	14.4.1
14.4-2	Test Specifics and Procedures	14.4.2

Table 1.8-2 (Sheet 6 of 7)

SUMMARY OF AP1000 STANDARD PLANT COMBINED LICENSE INFORMATION ITEMS

Item No.	Subject	Subsection
14.4-3	Conduct of Test Program	14.4.3
14.4-4	Review and Evaluation of Test Results	14.4.4
14.4-5	Testing Interface Requirements	14.4.5
14.4-6	First-Plant-Only and Three-Plant-Only Tests	14.4.6
15.7-1	Consequences of Tank Failure	15.7.6
16.1-1	Technical Specification Preliminary Information	16.1
16.3-1	Procedure to Control Operability of Investment Protection Systems, Structures and Components	16.3.2
17.5-1	Quality Assurance Design Phase	17.5
17.5-2	Quality Assurance for Procurement, Fabrication, Installation, Construction and Testing	17.5
17.5-3	Design Reliability Assurance Program/Site Specific List of Systems, Structures and Components	17.5
17.5-4	Quality Assurance Program for Operations	17.5
17.5-5	Maintaining Reliability of Risk-Significant SSCs	17.5
17.5-6	Maintenance Activities Relevant to Maintenance Rule	17.5
17.5-7	Operational Reliability Assurance Activities	17.5
17.5-8	Operational Reliability Assurance Program Integration with Quality Assurance Program	17.5
18.2-1	Execution of the NRC Approved Human Factors Engineering Program	18.2.6
18.2-2	Design of the Emergency Operations Facility	18.2.6
18.5-1	Task Analysis	18.5.4
18.5-2	Main Control Room	18.5.4
18.6-1	Plant Staffing	18.6.1
18.7-1	Execution and Documentation of the Human Reliability Analysis/Human Factors Engineering Integration	18.7.1
18.8-1	Execution and Documentation of the Human System Interface Design Implementation Plan	18.8.5
18.9-1	Procedure Development	18.9.1
18.10-1	Training Program Development	18.10.1

Table 1.8-2 (Sheet 7 of 7)

SUMMARY OF AP1000 STANDARD PLANT COMBINED LICENSE INFORMATION ITEMS

Item No.	Subject	Subsection
18.11-1	Verification and Validation of AP1000 Human Factors Engineering Program	18.11.1
18.14-1	Human Performance Monitoring	18.14
19.59.10-1	As-Built SSC HCLPF Comparison to Seismic Margin Evaluation	19.59.10.5
19.59.10-2	Evaluation of As-Built Plant Versus Design in AP1000 PRA and Site-Specific PRA External Events	19.59.10.5
19.59.10-3	Internal Fire and Internal Flood Analyses	19.59.10.5
19.59.10-4	Develop and Implement Severe Accident Management Guidance	19.59.10.5
19.59.10-5	Equipment Survivability	19.59.10.5
	Bulletins and Generic Letters (WCAP-15800, Revision 3, July 2004)	1.9.5.5
	Unresolved Safety Issues and Generic Safety Issues	Table 1.9-2

1.9 Compliance with Regulatory Criteria

1.9.1 Regulatory Guides

Regulatory guides are issued by the NRC in the following 10 broad divisions:

- Division 1 - Power Reactors
- Division 2 - Research and Test Reactors
- Division 3 - Fuels and Materials Facilities
- Division 4 - Environmental and Siting
- Division 5 - Materials and Plant Protection
- Division 6 - Products
- Division 7 - Transportation
- Division 8 - Occupational Health
- Division 9 - Antitrust and Financial Review
- Division 10 - General

Divisions 2, 3, 6, 7, 9, and 10 of the regulatory guides do not apply to the design and design certification phase of AP1000. The following sections provide a summary discussion of NRC Divisions 1, 4, 5, and 8 of the regulatory guides applicable to the design and design certification phase of AP1000.

Appendix 1A provides a discussion of AP1000 regulatory guide conformance.

1.9.1.1 Division 1 Regulatory Guides - Power Reactors

Currently there are approximately 190 Division 1 regulatory guides that have been issued by the NRC for implementation or for comment.

Appendix 1A provides an evaluation of the degree of AP1000 compliance with NRC Division 1 regulatory guides. The revisions of the regulatory guides against which AP1000 is evaluated are indicated. Any exceptions or alternatives to the provisions of the regulatory guides are identified and justification is provided. For those regulatory guides applicable to the AP1000 Table 1.9-1 identifies the appropriate DCD cross-references. The cross-referenced sections contain descriptive information applicable to the regulatory guide positions found in Appendix 1A.

The superseded or canceled regulatory guides are not considered in Appendix 1A or Table 1.9-1.

1.9.1.2 Division 4 Regulatory Guides - Environmental and Siting

One Division 4 regulatory guide, Regulatory Guide 4.7, merits discussion.

Regulatory Guide 4.7, "General Site Suitability Criteria for Nuclear Power Stations," provides guidelines for identifying suitable candidate sites for nuclear power stations. The guidance of this regulatory guide is considered as appropriate in the establishment of the AP1000 site interface criteria, and is described in Sections 2.1 and 2.5.

1.9.1.3 Division 5 Regulatory Guides - Materials and Plant Protection

Three Division 5 regulatory guides, Regulatory Guides 5.9, 5.12, and 5.65, merit discussion.

Regulatory Guide 5.9, "Guidelines for Germanium Spectroscopy Systems for Measurement of Special Nuclear Material," provides guidelines for data acquisition systems associated with the use of a lithium-drifted germanium gamma ray spectroscopy system. This regulatory guide is not applicable to AP1000 design certification.

Regulatory Guide 5.12, "General Use of Locks in the Protection and Control of Facilities and Special Nuclear Materials," provides guidelines for the selection and use of commercially available locks in the protection of facilities and special nuclear material. The guidance of this regulatory guide is considered as appropriate in the AP1000 design.

Regulatory Guide 5.65, "Vital Area Access Controls, Protection of Physical Security Equipment, and Key and Lock Controls," is not applicable to design certification.

1.9.1.4 Division 8 Regulatory Guides - Occupational Health

Two Division 8 regulatory guides, Regulatory Guides 8.8 and 8.19 merit discussion.

Regulatory Guide 8.8, "Information Relevant to Ensuring that Occupational Radiation Exposure at Nuclear Power Stations will be As Low As is Reasonably Achievable (ALARA)," provides NRC guidance for meeting the requirements of 10 CFR Part 20. This regulatory guide includes guidance in the following areas for maintaining radiation exposures ALARA:

- Overall program (e.g., policy, organization, and training)
- Facility and equipment design features
- Radiation protection program
- Radiation protection facilities, instrumentation, and equipment

Regulatory Guide 8.8 is written primarily for utility applicants and licensees. However, Westinghouse has established policy, design, and operational considerations that will be applied in the AP1000 design in accordance with this regulatory guide. These considerations are discussed in Section 12.1.

Regulatory Guide 8.19, "Occupational Radiation Dose Assessment in Light-Water Reactor Power Plants" describes a method acceptable to the NRC staff for performing an assessment of collective occupational radiation dose as part of the ongoing design review process involved in designing a light-water-cooled power reactor so that occupational radiation exposures will be ALARA. This regulatory guide includes guidance for estimating occupational radiation exposures (principally during the design stage) as a result of:

- Reactor operations and surveillance
- Routine maintenance
- Waste processing
- Refueling

- Inservice inspection
- Special maintenance

Occupational radiation exposure estimates that are in accordance with Regulatory Guide 8.19 are described in Section 12.4.

1.9.2 Compliance With Standard Review Plan (NUREG-0800)

WCAP-15799, "AP1000 Compliance with SRP Acceptance Criteria," provides the results of a review of the AP1000 compliance with the acceptance criteria for each section of the Standard Review Plan, NUREG-0800.

1.9.3 Three Mile Island Issues

This section identifies the Three Mile Island issues of 10 CFR 50.34(f) that are addressed by AP1000 design features or program plans. The additional issues of NUREG-0660 and NUREG-0737 that apply to the AP1000 are resolved in accordance with the guidance of NUREG-0933, with specific details provided in the applicable sections of the DCD.

Some of the 10 CFR 50.34(f) issues initially identified as applicable only to Boiling Water Reactors (BWRs) or Babcock and Wilcox plants have also been addressed for the AP1000 design. For example, the AP1000 design incorporates an automatic depressurization system with some similarity to that utilized for BWRs.

10 CFR 50.34(f):

(1)(i) Plant/Site Specific TMI-Related Risk Assessment (NUREG-0660 Item II.B.8)

"Perform a plant/site specific probabilistic risk assessment, the aim of which is to seek such improvements in the reliability of core and containment heat removal systems as are significant and practical and do not impact excessively on the plant."

AP1000 Response:

A plant-specific Probabilistic Risk Assessment (PRA) performed on the AP1000 design evaluates the plant in terms of core damage frequency and containment integrity. The PRA supports the design effort and establishes the capability of the design to meet established safety goals. Level 1 (Plant), 2 (Containment), and 3 (Site) PRA evaluations, including internal and external events:

- Demonstrate that the plant design meets the NRC safety goals
- Identify design vulnerabilities, evaluate alternate design features and operational strategies, and modify the design to reduce risk

The PRA process has been integrated into the design process to verify that the design effort meets the targeted goals and resolves the identified vulnerabilities. As a result, specific design changes were incorporated into the plant systems to improve the reliability of the core and containment heat removal systems.

Close interaction between the plant designers and PRA analysts is maintained to consider severe accident vulnerabilities as part of the design process. The AP1000 PRA is provided to the NRC as a separate document.

(1)(ii) Auxiliary Feedwater System Evaluation (NUREG-0737 Item II.E.1)

"Perform an evaluation of the proposed auxiliary feedwater system, to include (applicable to pressurized water reactors only): (A) a simplified Auxiliary Feedwater System reliability analysis using event-tree and fault-tree logic techniques, (B) a design review of Auxiliary Feedwater System, and (C) an evaluation of Auxiliary Feedwater System flow design bases and criteria."

AP1000 Response:

The AP1000 design does not utilize an auxiliary feedwater system. A nonsafety-related startup feedwater system is provided to remove the core decay heat after the reactor trip during postulated non-LOCA event. Decay heat removal maintains core subcooling and prevents water relief from the pressurizer safety valves by preventing heatup of the reactor coolant system. The startup feedwater pumps automatically start following anticipated transients resulting in low steam generator level. However, operation of the nonsafety-related startup feedwater system is not credited to mitigate licensing design basis accidents described in Chapter 15.

The safety-related passive core cooling system provides emergency core decay heat removal during transients, accidents, or whenever the normal nonsafety-related heat removal paths are unavailable.

The safety-related passive core cooling system design basis and criteria are described in Section 6.3.

(1)(iii) Reactor Coolant Pump Seals (NUREG-0737 Items II.K.2.16 and II.K.3.25)

"Perform an evaluation of the potential for and impact of reactor coolant pump seal damage following small-break loss of coolant accident with loss of offsite power. If damage cannot be precluded, provide an analysis of the limiting small-break loss of coolant accident with subsequent reactor coolant pump seal damage."

AP1000 Response:

The AP1000 design uses canned motor pumps for circulating primary reactor coolant through the reactor core, piping, and steam generators. The canned motor pump design does not have a seal that can fail and initiate reactor coolant system leakage.

(1)(iv) Automatic Power-Operated Relief Valve Isolation System (NUREG-0737 Item II.K.3.2)

"Perform an analysis of the probability of a small-break loss of coolant accident caused by a stuck-open power-operated relief valve. If this probability is a significant contributor to the probability of small-break loss of coolant accidents from all causes, provide a description and evaluation of the effect on small-break loss of coolant accident probability of an automatic

power-operated relief valve isolation system that would operate when the reactor coolant system pressure falls after the power-operated relief valve has opened."

AP1000 Response:

The AP1000 design does not include power-operated relief valves. The pressurizer volume is about 40 percent larger than the pressurizer volume in current plants with a comparable power rating. The larger pressurizer increases transient operation margins and prevents safety valve actuation in most accident situations. The pressurizer surge line is also larger to permit a more rapid transfer of coolant between the reactor coolant system and the pressurizer, and also to accommodate the automatic depressurization system first- to third-stage flow rates. The surge line limits the pressure drop during maximum anticipated surge (Condition II loss of load transient) to prevent exceeding the maximum reactor coolant system pressure limit.

Overpressure protection is provided by two totally enclosed pop-type safety valves. These valves are spring-loaded and self-actuated and they are designed to meet the requirements of the ASME Code, Section III. If the pressurizer pressure exceeds the set pressure, the safety valves start lifting. A temperature indicator in the discharge piping for each safety valve alarms on high temperature to alert the operator to the presence of high temperature fluid from leakage or when the valves open.

The AP1000 design also includes an automatic depressurization system. The system consists of four stages of valves. Three stages are connected to the pressurizer. The fourth stage is connected to the hot legs. These valves are not actuated on a high pressure signal. Design features are included to reduce the chance of spurious automatic depressurization system actuation including appropriate interlocks, 2-out-of-4 instrument actuation, fail as is valves, redundant, closed first, second, and third stage valves in each line, and redundant series controllers for forth stage valves. Probabilistic risk assessment is used to determine the probability of a loss of coolant accident caused by failure of the automatic depressurization system. Results of this evaluation are factored into the design process. See Chapter 5 and Section 6.3 for additional information.

(1)(v) Separation of HPCI and RCIC System Initiation Levels (NUREG-0737 Item II.K.3.13)

"Perform an evaluation of the safety effectiveness of providing for separation of high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) system initiation levels so that the RCIC system initiates at a higher water level than the HPCI system, and of providing that both systems restart on low water level. (For plants with high pressure core spray systems in lieu of high pressure coolant injection systems, substitute the words 'high pressure core spray' for 'high pressure coolant injection' and 'HPCS' for 'HPCI')."

AP1000 Response:

This issue is applicable to BWRs only and is not applicable to AP1000.

(1)(vi) Relief Valve Challenges (NUREG-0737 Item II.K.3.16)

"Perform a study to identify practicable system modifications that would reduce challenges and failures of relief valves, without compromising the performance of the valves or other systems."

AP1000 Response:

This issue is applicable to BWRs only and is not applicable to AP1000.

(1)(vii) Automatic Depressurization System Activation (NUREG-0737 Item II.K.3.18)

"Perform a feasibility and risk assessment study to determine the optimum automatic depressurization system design modifications that would eliminate the need for manual activation to ensure adequate core cooling."

AP1000 Response:

Although this issue is identified as applicable to BWRs only, the AP1000 design uses an automatic depressurization system with some similarity to that used on BWRs.

The automatic depressurization system actuates on Low-1 core makeup tank level, coincident with a core makeup tank actuation signal. Therefore manual actuation of the automatic depressurization system is not required to maintain core cooling. As discussed in Section (1)(i), PRA analysis confirms the reliability of the automatic actuation. Additional information is provided in Section 6.3.

(1)(viii) Core Spray and Low Pressure Coolant Injection Systems (NUREG-0737 Item II.K.3.21)

"Perform a study of the effect on all core-cooling modes under accident conditions of designing the core spray and low pressure coolant injection systems to ensure that the systems will automatically restart on loss of water level, after having been manually stopped, if an initiation signal is still present."

AP1000 Response:

This issue is applicable to BWRs only and is not applicable to AP1000.

(1)(ix) RCIC and HPCI Additional Space Cooling (NUREG-0737 Item II.K.3.24)

"Perform a study to determine the need for additional space cooling to ensure reliable long-term operation of the reactor core isolation cooling (RCIC) and high-pressure coolant injection (HPCI) systems, following a complete loss of offsite power to the plant for at least two (2) hours. (For plants with high pressure core spray systems in lieu of high pressure coolant injection systems, substitute the words 'high pressure core spray' for 'high pressure coolant injection' and 'HPCS' for 'HPCI')."

AP1000 Response:

This issue is applicable to BWRs only and is not applicable to AP1000.

(1)(x) Automatic Depressurization System Functionality During Accidents (NUREG-0737 Item II.K.3.28)

"Perform a study to ensure that the Automatic Depressurization System, valves, accumulators, and associated equipment and instrumentation will be capable of performing their intended functions during and following an accident situation, taking no credit for non-safety related equipment or instrumentation, and accounting for normal expected air (or nitrogen) leakage through valves."

AP1000 Response:

Although this issue is identified as applicable to BWRs only, the AP1000 uses a safety-related automatic depressurization system that is different from that presently used on BWRs. The AP1000 automatic depressurization system uses safety-related dc motor-operated valves and squib valves to initiate depressurization. The motive power for these valves is safety-related dc power. There is no nonsafety-related equipment or instrumentation, including instrument air or nitrogen supply, relied on in the operation of these valves.

These valves are designed and qualified to function in the conditions of an accident. They will also be subject of pre-operational and in-service testing. They will be included in the reliability assurance program. Additional information is provided in Section 6.3 for the passive core cooling system, subsection 3.9.3 for valve operability requirements, Chapter 14 for the initial test program, subsection 3.9.6 for in-service testing, and Section 16.2 for the reliability assurance program.

(1)(xi) Depressurization Methods/Rapid Cooldown (NUREG-0737 Item II.K.3.45)

"Provide an evaluation of depressurization methods, other than by full actuation of the automatic depressurization system, that would reduce the possibility of exceeding vessel integrity limits during rapid cooldown."

AP1000 Response:

This issue is applicable to BWRs only.

(1)(xii) Hydrogen Control System Evaluation (NUREG-0660 Item II.B.8)

"Perform an evaluation of alternative hydrogen control systems that would satisfy the requirements of paragraph (f)(2)(ix) of this section (50.34). As a minimum include consideration of a hydrogen ignition and post-accident inerting system. The evaluation shall include: (A) a comparison of costs and benefits of the alternative systems considered, (B) for the selected system, analyses and test data to verify compliance with the requirements of (f)(2)(ix) of this section (50.34), and (C) for the selected system, preliminary design descriptions of equipment, function, and layout."

AP1000 Response:

Continuous indication of hydrogen concentration in the containment atmosphere is provided. The containment hydrogen control system maintains hydrogen concentrations below 10 percent following the reaction of 100 percent of the active zircaloy cladding.

Hydrogen igniters control rapid releases of hydrogen during and after postulated degraded core and core melt accidents to maintain concentration below 10 percent.

Sufficient vent area is provided for each subcompartment in the containment to prevent high local concentrations of hydrogen.

See subsection 6.2.4 for additional information.

(2)(i) Simulator Capability (NUREG-0933 Item I.A.4.2)

"Provide simulator capability that correctly models the control room and includes the capability to simulate small-break loss of coolant accidents."

AP1000 Response:

Simulator capability is not included within the scope of the AP1000 design certification. Provision of simulator capability is the Combined License applicant's responsibility.

(2)(ii) Plant Procedures (NUREG-0933 Item I.C.9)

"Establish a program to begin during construction and follow into operation, for integrating and expanding current efforts to improve plant procedures. The scope of the program shall include emergency procedures, reliability analyses, human factors engineering, crisis management, operator training, and coordination with INPO and other industry efforts."

AP1000 Response:

As specified in Chapter 13 of the DCD, plant procedures, training of operations personnel and emergency planning are the responsibility of the Combined License applicant.

Activities in the Design Certification Process assist the Combined License applicant in performance of several of these tasks. First, the Emergency Response Guidelines (ERGs) provide the framework for development of site-specific emergency procedures. Second, DCD Section 18.10 describes the designers input for the design and implementation of training for a human factors engineering verification and validation (V&V) test subject. Also, DCD Section 17.4 describes the AP1000 reliability assurance program (RAP), which is instituted by the plant designer and carried on by the Combined License applicant. All reliability analyses performed under the reliability assurance program use common data bases from Westinghouse and industry sources such as INPO and EPRI. The reliability assurance program includes the identification of systems, structures, and components identified as major contributors to total risk, with the dominant failure modes identified and prioritized. The suggested means to prevent or

mitigate these failure modes form the basis for the plant surveillance, testing, and maintenance programs. See Chapter 18 for additional human factors engineering information.

(2)(iii) Control Room Design (NUREG-0737 Item I.D.1)

"Provide, for Commission review, a control room design that reflects state-of-the-art human factor principles prior to committing to fabrication or revision of fabricated control room panels and layouts."

AP1000 Response:

The human factors engineering design process of the AP1000 has been developed to conform with NUREG-0711, "Human Factors Engineering Program Review Model." The elements of the design process provide a structured top-down system analysis using accepted human factors engineering principles. The design of the main control room and the other operation and control centers reflect state-of-the-art human factors principles. See Appendix 1A for information on conformance with applicable regulatory guides. See Chapter 18 for additional information on the AP1000 human factors engineering design process.

(2)(iv) Safety Parameter Display System (NUREG-0737 Item I.D.2)

"Provide a plant safety parameter display console that will display to operators a minimum set of parameters defining the safety status of the plant, capable of displaying a full range of important plant parameters and data trends on demand, and capable of indicating when process limits are being approached or exceeded."

AP1000 Response:

The purpose of the plant safety parameter display console (or safety parameter display system) is to display important plant variables in the main control room in order to assist in rapidly and reliably determining the safety status of the plant.

The requirements for the safety parameter display system are specified during the main control room design process, and are met by the main control room design, specifically as part of the alarms, displays, and controls. The requirements for a safety parameter display system (NUREG-0696, Reference 1) are met by grouping the alarms by plant process or purpose, as directly related to the critical safety functions.

The process data presented on the graphic displays is similarly grouped, facilitating an easy transition for the operators. The safety parameter display system requirement for presentation of plant data in an analog fashion prior to reactor trip is met by the design of the graphic CRT displays.

Displays are available at the operator workstations, the remote shutdown workstation, and at the technical support center. See Chapter 18 for additional information pertaining to the safety parameter display system design.

(2)(v) Safety System Status Indication (NUREG-0933 Item I.D.3)

"Provide for automatic indication of the bypassed and [in]operable status of safety systems."

AP1000 Response:

The AP1000 main control room meets the NRC Regulatory Guide 1.47 recommendations, including automatic indication of bypassed and inoperable status of plant safety systems, as described in Appendix 1A.

Plant safety parameters, protection system status, and plant component status signals are processed by the protection and safety monitoring system and made available to the entire instrumentation and control system via the redundant monitor bus.

Class 1E signals are provided to the qualified data processor, which is part of the protection and safety monitoring system, for accident monitoring displays. The display of this data is incorporated in the process data displays on the graphic CRTs in the AP1000 main control room.

See Chapters 7 and 18 for additional information pertaining to bypass inoperable status indication. Appendix 1A describes conformance with Regulatory Guide 1.47.

(2)(vi) Reactor Coolant System High Point Vents (NUREG-0737 Item II.B.1)

"Provide the capability of high point venting of noncondensible gases from the reactor coolant system, and other systems that may be required to maintain adequate core cooling. Systems to achieve this capability shall be capable of being operated from the control room and their operation shall not lead to an unacceptable increase in the probability of loss-of-coolant accident or an unacceptable challenge to containment integrity."

AP1000 Response:

In the AP1000 design, the capability for remotely operated high point venting of the reactor coolant system is provided by the safety-related automatic depressurization system valves and the safety-related reactor vessel head vent system. Both of these vent paths discharge to the in-containment refueling water storage tank.

During loss of cooling accident events, the automatic depressurization system automatically depressurizes the reactor coolant system so that the passive core cooling system may effectively deliver core cooling flow. Depressurization via the automatic depressurization system results in creation of a gas-steam volume in the upper region of the vessel. This vapor volume expands down to the inside of the hot leg before it begins venting through the hot leg either via the automatic depressurization system paths connected to the pressurizer or directly from the hot legs via the fourth stage automatic depressurization system paths. This process provides an open injection and steam venting flow path through the reactor vessel, maintaining required core cooling flow.

The reactor vessel head vent system can also be operated from the main control room to directly vent from the top of the reactor vessel head. Subsection 5.4.12 provides additional information pertaining to the reactor coolant system venting capabilities.

(2)(vii) Plant Radiation Shielding (NUREG-0737 Item II.B.2)

"Perform radiation and shielding design reviews of spaces around systems that may, as a result of an accident, contain TID-14844 source term radioactive materials, and design as necessary to permit adequate access to important areas and to protect safety equipment from the radiation environment."

AP1000 Response:

Post-accident radiation sources, used in the shield design and assessment of post-accident access to vital areas, are addressed in subsection 12.2.1.3. The post-LOCA instantaneous and integrated source strengths as a function of time are also included as Tables 12.2-20 and 12.2-21, respectively. The sources are based on the core activity release model from Regulatory Guide 1.183, which supersedes the TID-14844 source term assumptions as reflected in Regulatory Guide 1.4.

Vital areas for post-accident personnel access are addressed in Section 12.3, including radiation zone maps that show projected dose rates in these areas and access routes for the various post-accident actions in vital areas. Time estimates have been made for ingress, egress, and performance of actions at the vital area locations and have been used in demonstrating that total individual radiation doses are limited to less than 5 rem and that Item II.B.2 of NUREG-0737 and GDC-19 requirements are met.

Environmental qualification of safety-related equipment is addressed in Section 3.11. The determination of the radiation environments during postulated accident situations considers the activity release model based on NUREG-1465, which supersedes the source term definition of Parts 1 and 4 of Item II.B.2 of NUREG-0737.

As noted in subsection 12.2.3, the Combined License applicant will address any additional contained radiation sources not identified in 12.2.1. Thus, appropriate source terms have been identified and used in establishing that the requirements of Item II.B.2 of NUREG-0737 and GDC 19 are met and the issues are resolved.

(2)(viii) Post-Accident Sampling (NUREG-0737 Item II.B.3)

"Provide a capability to promptly obtain and analyze samples from the reactor coolant system and containment that may contain TID-14844 source term radioactive materials without radiation exposures to any individual exceeding 5 rem to the whole-body or 50 rem to the extremities. Materials to be analyzed and quantified include certain radionuclides that are indicators of the degree of core damage (e.g, noble gases, iodines and cesiums, and non-volatile isotopes), hydrogen in the containment atmosphere, dissolved gases, chloride, and boron concentrations."

AP1000 Response:

Recently the NRC published a model Safety Evaluation Report on eliminating post-accident sampling system requirements from technical specifications for operating plants (Federal Register Volume 65, Number 211, October 31, 2000). The AP1000 sampling design is consistent with the approach in the Model safety evaluation report and not the guidance outlined in NUREG-0737 and Regulatory Guide 1.97. The primary sampling system design is consistent with contingency plans to obtain and analyze highly radioactive post-accident samples from the reactor coolant system, the containment sump, and the containment atmosphere.

(2)(ix) Hydrogen Control (NUREG-0660 Item II.B.8)

"Provide a system for hydrogen control that can safely accommodate hydrogen generated by the equivalent of a 100 percent fuel-clad metal-water reaction. Preliminary design information on the tentatively preferred system option of those being evaluated in paragraph (1)(xii) of this section (50.34) is sufficient at the construction permit stage. The hydrogen control system and associated systems shall provide, with reasonable assurance, that:

(A) Uniformly distributed hydrogen concentrations in the containment do not exceed 10 percent during and following an accident that releases an equivalent amount of hydrogen as would be generated from a 100 percent fuel-clad metal-water reaction, or that the post-accident atmosphere will not support hydrogen combustion.

(B) Combustible concentrations of hydrogen will not collect in areas where unintended combustion or detonation could cause loss of containment integrity or loss of appropriate mitigating features.

(C) Equipment necessary for achieving and maintaining safe shutdown of the plant and maintaining containment integrity will perform its safety function during and after being exposed to the environmental conditions attendant with the release of hydrogen generated by the equivalent of a 100 percent fuel-clad metal-water reaction including the environmental conditions created by activation of the hydrogen control system.

(D) If the method chosen for hydrogen control is a post-accident inerting system, inadvertent actuation of the system can be safely accommodated during plant operation."

AP1000 Response:

See the response provided for issue (1)(xii).

(2)(x) Reactor Coolant System Valve Testing (NUREG-0737 Item II.D.1)

"Provide a test program and associated model development and conduct tests to qualify reactor coolant system relief and safety valves and, for pressurized water reactors, power-operated relief valves, block valves, for all fluid conditions expected under operating conditions, transients and accidents. Consideration of anticipated transients without scram (ATWS) conditions shall be included in the test program. Actual testing under ATWS conditions need not be carried out until subsequent phases of the test program are developed."

AP1000 Response:

The AP1000 reactor coolant system design does not include power-operated relief valves and their associated block valves. However, the safety valve and discharge piping used in the AP1000 design will be either of design similar to those items tested by EPRI and documented in EPRI Report EPRI NP-2770-LD (Reference 2) or will be tested in accordance with the guidelines of Item [II.D.1] of NUREG-0737.

The AP1000 design includes automatic depressurization system valves which are used to depressurize the plant and establish conditions for injection from the accumulators and the in-containment refueling water storage tank. The operability of the automatic depressurization system valves and spargers is confirmed by a test program. See Section 1.5 for information pertaining to the testing program.

Accident analyses for the AP1000 determine fluid conditions expected under operating conditions, transients, and accidents, and the postulated system responses to these conditions, including the operation of reactor coolant system safety valves. Anticipated transients without scram events are analyzed. Appropriate valve qualification documentation is maintained.

(2)(xi) Valve Position Indication (NUREG-0737 Item II.D.3)

"Provide direct indication of relief and safety valve position (open or closed) in the control room."

AP1000 Response:

The AP1000 design does not include power-operated relief valves and their associated block valves from the reactor coolant system.

Direct indication of relief and safety valve position (open or closed) is provided in the main control room.

(2)(xii) Auxiliary Feedwater System Initiation and Indication (NUREG-0737 Item II.E.1.2)

"Provide automatic and manual auxiliary feedwater system initiation, and provide auxiliary feedwater system flow indication in the control room."

AP1000 Response:

As previously noted in the AP1000 response to Issue (1)(ii), the AP1000 design includes a nonsafety-related startup feedwater system, but not an auxiliary feedwater system. Flow indication of the startup feedwater system is provided in the main control room.

The startup feedwater pumps automatically start following anticipated transients resulting in low steam generator level. The startup feedwater control valves automatically control feedwater flow to the steam generators during operation. They can also be operated manually from the main control room.

The safety-related passive core cooling system provides for emergency core decay heat removal during transients, accidents, or whenever the normal heat removal paths are unavailable. Automatic and manual actuation and flow rate indication are available in the main control room.

(2)(xiii) Pressurizer Heater Power Supplies (NUREG-0737 Item II.E.3.1)

"Provide pressurizer heater power supply and associated motive and control power interfaces sufficient to establish and maintain natural circulation in hot standby conditions with only onsite power available."

AP1000 Response:

The AP1000 pressurizer heaters are powered from the nonsafety-related ac power system. During loss of offsite power events, a portion of the pressurizer heaters are capable of being powered from the nonsafety-related onsite standby power system. The pressurizer heaters are capable of establishing and maintaining natural circulation in hot standby condition, with only the diesel generators supplying electrical power.

With only safety-related dc (Class 1E dc) power available, the safety-related passive core cooling system can establish and maintain natural circulation cooling using the passive residual heat removal heat exchangers, transferring the decay heat to the in-containment refueling water storage tank water and to the passive containment cooling system.

Therefore, the nonsafety-related pressurizer heaters are not required for core decay heat removal following a loss of offsite power. See Section 8.3 for additional information.

(2)(xiv) Containment Isolation System (NUREG-0737 Item II.E.4.2)

"Provide containment isolation systems that: (A) ensure all nonessential systems are isolated automatically by the containment isolation system, (B) for each non-essential penetration (except instrument lines) have two isolation barriers in series, (C) do not result in reopening of the containment isolation valves on resetting of the isolation signal, (D) utilize a containment set point pressure for initiating containment isolation as low as is compatible with normal operation, and (E) include automatic closing on a high radiation signal for all systems that provide a path to the environs."

AP1000 Response:

The AP1000 containment isolation design satisfies NRC requirements, including post-TMI requirements. In general, this means that two barriers are provided -- one inside containment and the other outside containment. Usually these barriers are valves, but in some cases they are closed, seismic Category I piping systems not connected to the reactor coolant system or to the containment atmosphere. Table 6.2.3-1 identifies containment isolation design provisions for mechanical penetrations. The isolation signal and maximum closure times are defined for each remotely operated valve. Containment penetrations, other than equipment hatches and flanges, incorporate two isolation barriers in series.

The AP1000 design incorporates a reduction in the number of required penetrations compared to the number in previous plant designs. The majority of these penetrations are normally closed. Those few that are normally open, use automatically closed isolation valves.

Containment isolation is automatically actuated by a safeguards actuation signal, using two-out-of-four coincident logic. The containment isolation actuation is set as low as reasonable without creating potential for spurious trips during normal operations. Containment isolation can also be initiated manually from the main control room. Containment penetrations do not automatically reopen on the resetting of the isolation signal. See subsection 6.2.3 for additional information.

(2)(xv) Containment Purging/Venting (NUREG-0933 Item II.E.4.4)

"Provide a capability for containment purging/venting designed to minimize the purging time consistent with ALARA principles for occupational exposure. Provide and demonstrate high assurance that the purge system will reliably isolate under accident conditions."

AP1000 Response:

Containment purging for the AP1000 is provided by the nonsafety-related containment air filtration system. The function of the system is to clean up the containment atmosphere to acceptable radiation levels during plant operation and prior to personnel entry. It can also be used for containment pressure equalization.

The containment air filtration system is designed to reliably isolate under accident conditions. There are two penetrations and two containment filtration subsystems for AP1000.

See subsection 9.4.7 for additional information.

(2)(xvi) ECCS Actuation Cycles (NUREG-0933 Item II.E.5.1)

"Establish a design criterion for the allowable number of actuation cycles of the emergency core cooling system and reactor protection system consistent with the expected occurrence rates of severe overcooling events (considering both the expected transients and accidents)."

AP1000 Response:

This issue is applicable to Babcock & Wilcox designs only.

The AP1000 design uses the passive core cooling system to provide emergency reactor coolant inventory control and emergency decay heat removal. Component design criteria have been established for the number of actuation cycles for the passive core cooling system. The identified actuation cycles include inadvertent actuation, as well as the system response to expected plant trip occurrences, including overcooling events.

Automatic depressurization system operation is not expected for either design basis or best estimate overcooling events. See subsection 3.9.1 for additional information.

(2)(xvii) Specific Accident Monitoring Instrumentation (NUREG-0737 Item II.F.1)

"Provide instrumentation to measure, record and readout in the control room: (A) containment pressure, (B) containment water level, (C) containment hydrogen concentration, (D) containment radiation intensity (high level), and (E) noble gas effluents at all potential accident release points. Provide for continuous sampling of radioactive iodines and particulates in gaseous effluents from all potential accident release points, and for onsite capability to analyze and measure these samples."

AP1000 Response:

AP1000 post-accident monitoring is described in Chapter 7.

AP1000 post-accident monitoring provides for indication of the specified parameters as follows:

- Containment pressure
- Containment water level
- Containment radiation intensity (high level)
- Noble gas effluents - to ascertain reactor coolant system integrity

The hydrogen monitors are not part of post-accident monitoring.

Other noble gas effluents are designated Type E variables and include information to permit the operators to:

- Monitor the habitability of the main control room
- Monitor plant areas where access may be required to service equipment necessary to monitor or mitigate the consequences of an accident
- Estimate the magnitude of release of radioactive materials through identified pathways
- Monitor radiation levels and radioactivity in the environment surrounding the plant

DCD subsection 11.5.5 has additional information on measurement of radioactive effluents and conformance with Regulatory Guide 1.97.

The AP1000 primary sampling system is designed to provide post accident sampling functions. See DCD subsection 9.3.3.1 for additional information on the post accident sampling system.

The human factors aspects of the AP1000 are discussed in Chapter 18.

(2)(xviii) Inadequate Core Cooling Instrumentation (NUREG-0737 Item II.F.2)

"Provide instruments that provide in the control room an unambiguous indication of inadequate core cooling, such as primary coolant saturation meters in PWRs, and a suitable combination of signals from indicators of coolant level in the reactor vessel and in-core thermocouples in PWRs and BWRs."

AP1000 Response:

The AP1000 reactor system includes instrumentation for detecting voids in the reactor vessel head and other reactor vessel inventory deficits that could lead to inadequate core cooling.

The available instrumentation includes core subcooling margin monitors, core exit thermocouples, pressurizer level indicators, reactor coolant system reactor vessel level, and reactor coolant pump status (motor current). Reactor vessel level indication is provided from a range in the vessel from the bottom of the hot leg to approximately the reactor vessel mating flange via level instrumentation connected to the hot legs.

The AP1000 features that provide margin to or indication of inadequate core cooling include the following:

- A larger pressurizer than most current PWRs, with a pressurizer that is located above the reactor pressure vessel head
- No automatic power-operated relief valves
- An improved reactor vessel head venting capability
- A passive core cooling system
- A passive containment cooling system
- No dependence on ac power to maintain adequate core and containment cooling
- Reactor coolant system hot leg level instrumentation
- Improved reactor system instrumentation
- Core subcooling monitoring

See Sections 6.3 and 7.5 for additional information.

(2)(xix) Post-Accident Monitoring Instrumentation (NUREG-0933 Item II.F.3)

"Provide instrumentation adequate for monitoring plant conditions following an accident that includes core damage."

AP1000 Response:

The AP1000 post-accident monitoring system was developed by using Regulatory Guide 1.97 as a guidance document.

Data used for post-accident monitoring is displayed either by the normal control room display system or by the qualified data processing system.

The normal control room display system is used for display of nonsafety-related signals which are not required to be displayed by a qualified system. The qualified data processing system provides for the display of signals which must be displayed by a qualified system.

The qualified data processing system is a microprocessor-based, safety-related system that provides instrumentation to monitor the plant variables and systems during and following an accident. The system consists of two independent, electrically isolated, physically separated divisions.

Additional details pertaining to this system are provided in the AP1000 response to issue (2)(xvii) and in Chapter 7.

(2)(xx) Power Supplies for Pressurizer Relief Valves, Block Valves, and Level Indicators (NUREG-0737 Item II.G.1)

"Provide power supplies for pressurizer relief valves, block valves, and level indicators such that: (A) level indicators are powered from vital buses, (B) motive and control power connections to the emergency power sources are through devices qualified in accordance with requirements applicable to systems important to safety, and (C) electric power is provided from emergency power sources."

AP1000 Response:

The AP1000 design does not include power-operated relief valves and their associated block valves from the reactor coolant system.

Pressurizer level indication is provided by instrumentation powered from the Class 1E dc and UPS system. The system provides safety-related, uninterruptable power for the Class 1E plant instrumentation, control, monitoring, and other vital functions, including safety-related components that are essential for safe shutdown of the plant.

The Class 1E direct current system is designed such that these critical plant loads are powered during emergency plant conditions when both onsite and offsite ac power sources are unavailable.

See Chapter 7 and Section 8.3 for additional information.

(2)(xxi) Auxiliary Heat Removal Systems (NUREG-0933 Item II.K.1.22)

"Design auxiliary heat removal systems such that necessary automatic and manual actions can be taken to ensure proper functioning when the main feedwater system is not operable."

AP1000 Response:

Although this issue is applicable to BWRs only, there are some considerations for AP1000.

Following a loss of main feedwater for the AP1000, there are a number of plant systems that automatically actuate to provide decay heat removal. The startup feedwater system is a nonsafety-

related system, that can be powered by the nonsafety-related diesel generators, and is automatically actuated and controlled by steam generator level.

For design basis events, the safety-related passive core cooling system includes a passive residual heat removal heat exchanger which automatically actuates to provide emergency core decay heat removal if the nonsafety-related systems are not available.

The AP1000 main control room meets the NRC guidelines for manual actuation of protective functions including those that are used in the event of a loss of normal feedwater.

See Sections 6.3 and 10.4 for additional information.

(2)(xxii) Failure Mode and Effects Analysis for Control Systems (NUREG-0933 Item II.K.2.9)

"Provide a failure modes and effects analysis of the integrated control system to include consideration of failures and effects of input and output signals to the integrated control system."

AP1000 Response:

This issue is applicable to Babcock & Wilcox plants only.

(2)(xxiii) Safety-Grade Anticipatory Reactor Trip (NUREG-0737 Item II.K.2.10)

"Provide, as part of the reactor protection system, an anticipatory reactor trip that would be actuated on loss of main feedwater and on turbine trip."

AP1000 Response:

This issue is applicable to Babcock & Wilcox plants only.

The AP1000 trip logic includes an anticipatory reactor trip for loss of main feedwater using low steam generator water level. See Section 7.2 for additional information.

Since the AP1000 design does not include power-operated relief valves and their associated block valves in the reactor coolant system, the anticipatory reactor trip on turbine trip is not required for AP1000.

(2)(xxiv) Central Water Level Recording (NUREG-0933 Item II.K.3.23)

"Provide the capability to record reactor vessel water level in one location on recorders that meet normal post-accident recording requirements."

AP1000 Response:

This issue is applicable to BWRs only.

(2)(xxv) Emergency Response Facilities (NUREG-0737 Item III.A.1.2)

"Provide an onsite technical support center, an onsite operational support center, and, for construction permit applications only, a nearsite emergency operations facility."

AP1000 Response:

The AP1000 provides for an onsite technical support center and an operational support center. See the figures in Section 1.2 for additional information on the location. The detailed design of the workstations and the associated man-machine interface for the technical support center and the operational support center is guided by the human factors engineering design process described in Chapter 18 of the DCD. The offsite emergency response facility is the responsibility of the Combined License applicant. The implementation and results of the human factors engineering design process when applied to the technical support center and the operational support center is the responsibility of the Combined License applicant.

(2)(xxvi) Leakage Control Outside Containment (NUREG-0737 Item III.D.1.1)

"Provide for leakage control and detection in the design of systems outside containment that contain (or might contain) TID-14844 source term radioactive materials following an accident. Applicants shall submit a leakage control program, including an initial test program, a schedule for retesting these systems, and the actions to be taken for minimizing leakage from such systems. The goal is to minimize potential exposures to workers and public, and to provide reasonable assurance that excessive leakage will not prevent the use of systems needed in an emergency."

AP1000 Response:

As described in issue (2)(vii), the safety-related AP1000 passive systems do not recirculate radioactive fluids outside of containment following an accident. A nonsafety-related system can be used to recirculate coolant outside of containment following an accident, but this system is not operated when high containment radiation levels exist.

(2)(xxvii) In-Plant Monitoring (NUREG-0737 Item III.D.3.3)

"Provide for monitoring of inplant radiation and airborne radioactivity as appropriate for a broad range of routine and accident conditions."

AP1000 Response:

Area radiation monitors (ARMs) are provided to supplement the personnel and area radiation survey provisions of the AP1000 health physics program described in Section 12.5 and to comply with the personnel radiation protection guidelines of 10 CFR 20, 10 CFR 50, 10 CFR 70, and Regulatory Guides 1.97, 8.2, and 8.8. In addition to the installed detectors, periodic plant environmental surveillance is established.

(2)(xxviii) Control Room Habitability (NUREG-0737 Item III.D.3.4)

"Evaluate potential pathways for radioactivity and radiation that may lead to control room habitability problems under accident conditions resulting in a TID-14844 source term release, and make necessary design provisions to preclude such problems."

AP1000 Response:

Normally, a nonsafety-related HVAC system keeps the AP1000 main control room slightly pressurized to prevent infiltration of air from other plant areas. During accident conditions, a safety-related isolation of the main control room is automatically actuated.

Upon the loss of nonsafety-related ac power, the main control room environment is sufficient to protect the operators and support the man-machine interfaces necessary to establish and maintain safe shutdown conditions for the plant following postulated design basis accident conditions. The sources are based on the core activity release model from Regulatory Guide 1.183, which supersedes the TID-14844 source term assumptions as reflected in Regulatory Guide 1.4.

The main control room is sealed with safety-related connections to a safety-related compressed air breathing source. This compressed air system provides continued pressurization and a source of fresh air for operator habitability. The air supply is sized to last for 72 hours following an accident. It is expected that the onsite nonsafety-related normal HVAC system will be operational before the installed compressed air supply is exhausted.

The nonsafety-related HVAC system, equipped with a refrigeration-type air conditioning unit, normally provides main control room cooling. This equipment is powered from the onsite diesel generators. If the normal HVAC system is not available, outside air is not allowed into the main control room, and the safety-related compressed air storage system is actuated.

(3)(i) Industry Experience (NUREG-0737 Item I.C.5)

"Provide administrative procedures for evaluating operating, design, and construction experience and for ensuring that applicable important industry experiences will be provided in a timely manner to those designing and constructing the plant."

AP1000 Response:

AP1000 design engineers are continually involved in reviewing industry experiences from sources such as NRC Bulletins, Licensee Event Reports, NRC request for information letters to holders of operating licenses for nuclear power reactors, Federal Register information, and generic letters. Lessons learned experience was incorporated in the AP600 through the Westinghouse participation in developing Volume III of the ALWR Utility Requirements Document and participation in the ALWR Utility Steering Committee activities. The AP1000 design is closely based on the AP6000. See Section 1.9.5.5 for additional information.

(3)(ii) Quality Assurance List (NUREG-0933 Item I.F.1)

"Ensure that the quality assurance list required by Criterion II, Appendix B, 10 CFR Part 50 includes all structures, systems and components important to safety."

AP1000 Response:

The AP1000 Quality Assurance Plan is described in Chapter 17. Structures, systems, and components are classified as described in Section 3.2.

(3)(iii) Quality Assurance Program (NUREG-0737 Item I.F.2)

"Establish a quality assurance program based on consideration of: (A) ensuring independence of the organization performing checking functions from the organization responsible for performing the functions; (B) performing quality assurance/quality control functions at construction sites to the maximum feasible extent; (C) including Quality Assurance personnel in the documented review of and concurrence in quality related procedures associated with design, construction and installation; (D) establishing criteria for determining Quality Assurance programmatic requirements; (E) establishing qualification requirements for Quality Assurance and Quality Control personnel; (F) sizing the Quality Assurance staff commensurate with its duties and responsibilities; (G) establishing procedures for maintenance of "as-built" documentation; and (H) providing a Quality Assurance role in design and analysis activities."

AP1000 Response:

The AP1000 Quality Assurance Plan described in Chapter 17 meets the requirements of issue 1.F.2.

(3)(iv) Dedicated Containment Penetrations (NUREG-0660 Item II.B.8)

"Provide one or more dedicated containment penetrations, equivalent in size to a single 3-foot diameter opening, in order not to preclude future installation of systems to prevent containment failure, such as a filtered vented containment system."

AP1000 Response:

The containment analysis for the AP1000, including PRA and severe accident assessments, demonstrate that the containment, with its passive heat rejection capability, does not need a filtered vent to prevent overpressurization.

The 36-inch diameter containment air filtration system penetration provided for AP1000 meets the requirement of 10 CFR 50.34(f)(3)(iv). See Figure 9.4.7-1, note 6, for additional information.

(3)(v) Containment Design (NUREG-0660 Item II.B.8)

"Provide preliminary design information at a level of detail consistent with that normally required at the construction permit stage of review sufficient to demonstrate that:

(A)(1) Containment integrity will be maintained (i.e., for steel containments by meeting the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Division 1, Subarticle NE-3220, Service Level C Limits, except that evaluation of instability is not required, considering pressure and dead load alone. For concrete containments by meeting the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Division 2 Subarticle CC-3720,

Factored Load Category, considering pressure and dead load alone) during an accident that releases hydrogen generated from 100 percent fuel clad metal-water reaction accompanied by either hydrogen burning or the added pressure from post-accident inerting assuming carbon dioxide is the inerting agent. As a minimum, the specific code requirements set forth above, appropriate for each type of containment, will be met for a combination of dead load and an internal pressure of 45 psig. Modest deviations from these criteria will be considered by the staff, if good cause is shown by an applicant. Systems necessary to ensure containment integrity shall also be demonstrated to perform their function under these conditions.

(2) Subarticle NE-3220, Division 1, and subarticle CC-3720, Division 2, of Section III of the July 1, 1980 ASME Boiler and Pressure Vessel Code, which are referenced in paragraph (f)(3)(v)(A)(1) and (f)(3) (v)(B)(1) of this section, were approved for incorporation by reference by the Director of the Office of the Federal Register. A notice of any changes made to the material incorporated by reference will be published in the Federal Register. . . .

(B)(1) Containment structure loadings produced by an inadvertent full actuation of a post-accident inerting hydrogen control system (assuming carbon dioxide), but not including seismic or design basis accident loadings will not produce stresses in steel containments in excess of the limits set forth in the ASME Boiler and Pressure Vessel Code, Section III, Division 1, Subarticle NE-3220, Service Level A Limits, except that evaluation of instability is not required (for concrete containments the loadings specified above will not produce strains in the containment liner in excess of the limits set forth in the ASME Boiler and Pressure Vessel Code, Section III, Division 2, Subarticle CC-3720, Service Load Category), (2) The containment has the capability to safely withstand pressure tests at 1.10 and 1.15 times (for steel and concrete containments, respectively) the pressure calculated to result from carbon dioxide inerting."

AP1000 Response:

The AP1000 containment vessel is designed to meet the requirements of the ASME Code, Section III, Division I, Subsection NE. A severe accident containment analysis is conducted to support the design effort. The results of the analysis are fission product source terms and plant thermal-hydraulic response for each of the accident sequences chosen to be representative of the plant damage states determined in level 1 PRA analysis.

Results of the analysis indicate that containment failure is not predicted for cases in which the passive containment cooling system cooling water is available. The hydrogen igniter system controls hydrogen and mitigates threats to the containment due to hydrogen.

See Section 6.2 for additional information.

(3)(vi) Hydrogen Recombiners (NUREG-0737 Item II.E.4.1)

"For plant designs with external hydrogen recombiners, provide redundant dedicated containment penetrations so that, assuming a single failure, the recombiner systems can be connected to the containment atmosphere."

AP1000 Response:

Since external hydrogen recombiners are not provided for the AP1000, this requirement is not applicable. See Section 6.2 for additional information.

(3)(vii) Management Plan (NUREG-0933 Item II.J.3.1)

"Provide a description of the management plan for design and construction activities, to include: (A) the organizational and management structure singularly responsible for direction of design and construction of the proposed plant; (B) technical resources director by the applicant; (C) details of the interaction of design and construction within the applicant's organization and the manner by which the applicant will ensure close integration of the architect engineer and the nuclear steam supply vendor; (D) proposed procedures for handling the transition to operation; (E) the degree of top level management oversight and technical control to be exercised by the applicant during design and construction, including the preparation and implementation of procedures necessary to guide the effort."

AP1000 Response:

The AP1000 design team has developed a management plan for the AP1000 project which consists of a properly structured organization with open lines of communication, clearly defined responsibilities, well-coordinated technical efforts, and appropriate control channels. The procedures to be used in the construction, startup, and operation phases of the plant are provided by the Combined License applicant.

1.9.4 Unresolved Safety Issues and Generic Safety Issues

Proposed technical resolutions of Unresolved Safety Issues and medium- and high-priority Generic Safety Issues, as identified in NUREG-0933, Reference 3 are required for new plants as part of the NRC policy on severe accidents and are required for design certification in accordance with 10 CFR 52.47(a)(1)(iv).

The current program for identifying and establishing the priority of open safety issues is summarized in NUREG-0933. This program provides for the prioritization and tracking of previously categorized Unresolved Safety Issues and Generic Safety Issues, New Generic Issues, TMI Action Plan Items Under Development, and Human Factors Program Plan Issues.

The following subsection reviews each of the NUREG-0933 safety issues and identifies the safety issues that are applicable to the AP1000. For each of these issues guidance is provided on how the issue is addressed for the AP1000.

1.9.4.1 Review of NRC List of Unresolved Safety Issues and Generic Safety Issues

Applicants for design certification are required by 10 CFR 52.47(a)(1)(iv) to identify:

"Proposed technical resolutions of those Unresolved Safety Issues and medium- and high-priority Generic Safety Issues which are identified in the version of NUREG-0933 current on the date six months prior to application and which are technically relevant to the design."

NUREG-0933, "A Prioritization of Generic Safety Issues," through Supplement 25 identifies hundreds of issues. The issues tabulated in Supplement 25 were reviewed to determine which issues are technically relevant to the AP1000 design. In this review process, the following screening criteria were applied:

a. Issue has been prioritized as **Low**, **Drop**, or has not been prioritized.

b. Issue is not an AP1000 design issue. Issue is applicable to GE, B&W, or CE designs only.

c. Issue resolved with no new requirements.

d. Issue is not a design issue (Environmental Issue, Licensing Issue, Regulatory Impact Issue, or covered in an existing NRC program).

e. Issue superseded by one or more issues.

f. Issue is not an AP1000 design certification issue. Issue is applicable to NTOL plants only, responsibility of combined license applicant, or issue is limited to current generation operating plants.

Issues meeting one or more of the preceding screening criteria were screened out of the review process as issues that are not applicable to the AP1000 design. The remaining issues fall into one of the following two categories:

g. Issue is resolved by establishment of new regulatory requirements and/or guidance.

h. Issue is unresolved pending generic resolution (e.g., prioritized as **High**, **Medium**, or possible resolution identified).

Table 1.9-2 identifies the results of the screening review. For those issues identified as relevant to the AP1000 design (i.e., issues screened as **g** or **h**), Table 1.9-2 identifies the DCD subsection that addresses the issue.

1.9.4.2 AP1000 Resolution of Unresolved Safety Issues and Generic Safety Issues

1.9.4.2.1 TMI Action Plan Issues

TMI Action Plan issues that were not incorporated in 10CFR50.34(f) are addressed in the following. Those issues incorporated into 10CFR50.34(f) are addressed in subsection 1.9.3.

I.D.5(2) Plant Status and Post-Accident Monitoring Discussion:

TMI action plant item I.D.5(2) addresses the need to improve the operators' ability to prevent, diagnose and properly respond to accidents. The emphasis is on the information needs (i.e., indication of plant status) of the operator. This issue was resolved with the issuance of Revision 2 to Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant Environs Conditions During and Following an Accident."

AP1000 Response:

The AP1000 conforms to and meets the intent of Regulatory Guide 1.97. Regulatory Guide 1.97 provides the requirements for post-accident monitoring of nuclear reactor safety parameters, including plant process parameters important to safety and the monitoring of effluent paths and plant environs for radioactivity. These guidelines include definition and categorization of plant variables that are available to the main control room operators for monitoring the plant safety status following a design basis event.

For the AP1000, an analysis is conducted to identify the appropriate variables and to establish the appropriate design basis and qualification criteria for instrumentation used by the operator for monitoring conditions in the reactor coolant system, the secondary heat removal system, the containment, and the systems used for attaining a safe shutdown condition, as discussed in Section 7.5.

The instrumentation is used by the operator to monitor and maintain the safety of the plant during operating conditions, including anticipated operational occurrences and accident and post-accident conditions. A set of plant parameters identified according to the Regulatory Guide 1.97 guidelines are processed and displayed by the qualified data processing system (QDPS), which is discussed in subsection 18.8. The verification and validation (V&V) of the QDPS complies with the V&V process described in Section 18.11.

I.D.5(3) On-Line Reactor Surveillance System

Discussion:

TMI action plan item I.D.5(3) addresses the benefit to plant safety and operations of continuous on-line automated surveillance systems. Continuous on-line surveillance systems that automatically monitor reactors can assist plant operations by providing diagnostic information which can predict anomalous behavior.

Various methods of on-line reactor surveillance have been used, including neutron noise monitoring in boiling water reactors (BWRs) to detect internals vibration, and pressure noise surveillance at TMI-2 to monitor primary loop degasification.

AP1000 Response:

The AP1000 reactor coolant pressure boundary is monitored for leaks from the reactor coolant and associated systems by a variety of components located in multiple systems. The leak detection system provides information permitting the plant operators to take corrective action if any detected leakage exceeds technical specifications. The leak detection system is designed according to the requirements of 10 CFR 50, Appendix A, General Design Criterion 30. The system provides a means to detect and, to the extent practical, to identify the source of the reactor coolant pressure boundary leakage. DCD subsection 5.2.5 provides further discussion of leak detection.

A digital metal impact monitoring system (DMIMS) monitors the reactor coolant system for the presence of loose metallic parts. This system conforms with the guidance provided in Regulatory Guide 1.133, Rev. 1, May 1981. An advanced microprocessor-based system, employing digital

technology, automatically actuates audible and visual alarms if a signal exceeds the preset alarm level.

I.F.1 Expand Quality Assurance List

Discussion:

Item I.F.1 addressed the issue of systems that are "important to safety" that are not on the Quality Assurance List. The suggestion was made that equipment important to safety be ranked and that ranking used to determine systems that should be added to the Quality Assurance List. This approach has not been implemented by the NRC on either a generic or cases-by case basis. In NUREG-0933 this item was classified as resolved with no additional requirements established.

AP1000 Response:

The requirements of 10 CFR Appendix B apply to safety-related systems and components. See subsection 3.2.2 for a discussion of the AP1000 equipment classification system and the associated quality assurance requirements, including requirements for nonsafety-related systems.

I.G.1 Training Requirements

Discussion:

Item I.G.1 included the issue of natural circulation testing for use as input into operator training.

AP1000 Response:

For the AP1000, natural circulation heat removal using the steam generators is not safety-related, as in current plants. This safety-related function is performed by the passive residual heat removal system. Natural circulation heat removal via the passive residual heat removal heat exchanger is tested for every plant during hot functional testing. This testing of passive residual heat removal system meets the intent of the requirement to perform natural circulation testing and the results of this testing is factored into the operator training.

For the AP1000, the tests outlined below are contained in the AP1000 initial test plan and demonstrate the effectiveness of natural circulation cooling.

1. During hot functional testing, prior to fuel load, with the reactor coolant pumps not running and no onsite power available, the heat removal capability of the passive residual heat removal heat exchanger with natural circulation flow is verified (See subsection 14.2.9.1.3, item e).

2. After fuel loading, but prior to criticality, with the reactor system at no-load operating temperature and pressure and all reactor coolant pumps operating, the depressurization rate is determined by de-energizing the heaters and pressure is further reduced through use of sprays (See subsection 14.2.10.1.19).

3. After criticality is achieved and the plant is at ~ 3% power, the plant is placed in a natural circulation mode by tripping all reactor coolant pumps and observing the plant response using the steam generators (See subsection 14.2.10.3.6) and then using the PRHR (see subsection 14.2.10.3.7) as the primary heat sinks. These tests are performed for the first plant only.

4. A loss-of-offsite power test is performed with the plant at minimum power level supplying normal house loads. The turbine is tripped and the plant is placed in a stable condition using batteries and the diesel generator (See subsection 14.2.10.4.26).

5. Data obtained from the first plant only natural circulation tests using the steam generators and PRHR is provided for operator training on a plant simulator at the earliest opportunity. Operating training for subsequent plants is also obtained while performing the hot functional PRHR natural circulation test described in item 1 above.

This response as modified for the AP1000 design is consistent with the response to NUREG-0737, action item I.G.1 which provided a proposal for low power testing of existing and future Westinghouse pressurized water reactors in Attachment 4 to letter NS-EPR-2465 from Westinghouse (E. P. Rahe) to the NRC (H. R. Denton) dated July 8, 1981.

I.G.2 Scope of Test Program

Discussion:

TMI Action Plan Items I.G.2 recommended additional testing during preoperational and startup programs to search for anomalies in a plants response to transients. The Standard Review Plan, Section 14 was revised to provide additional guidance for preoperational and startup test programs.

AP1000 Response:

The program plan for preoperational and startup testing of the AP1000 is in Section 14.2. This section addresses the Standard Review Plan, Section 14. The conformance with Standard Review Plan, Section 14 is outlined in AP1000 Compliance with SRP Acceptance Criteria, WCAP-15799.

II.E.1.3 Update Standard Review Plan and Develop Regulatory Guide

Discussion:

This item was a requirement to update Section 10.4.9 of the Standard Review Plan to address the requirements of Items II.E.1.1 and II.F.1.2 for auxiliary feedwater systems. Standard Review Plan 10.4.9 was revised and this issue is classified as resolved.

AP1000 Response:

The AP1000 does not have a safety-related auxiliary feedwater system. For conformance of the AP1000 with Items II.E.1.1 and II.E.1.2 see the write-up for (1)(ii) and (2)(xii) in subsection 1.9.3. For conformance with Standard Review Plan Section 10.4.9 see WCAP-15799.

II.E.6.1 Test Adequacy Study

Discussion:

This item was intended to establish the adequacy of requirements for safety-related valve testing. Subsequent to this item, expanded requirements were written into the ASME OM Code for valve testing.

AP1000 Response:

The AP1000 is designed for an in-service test program in accordance with the ASME OM Code. See subsection 3.9.6 for additional information on the in-service testing program plan.

II.K.1(10) Review and Modify Procedures for Removing Safety-related Systems from Service

Discussion:

This item required operating plants to review and modify (as required) their procedures for removing safety-related systems from service to assure operability status is known.

AP1000 Response:

Procedure development is the responsibility of the Combined License applicant as stated in DCD Section 13.5.

II.K.1(13) Propose Technical Specification Changes Reflecting Implementation of All Bulletin Items.

Discussion:

This item required that operating plants propose technical specification changes to address Bulletin items.

AP1000 Response:

The AP1000 Technical Specifications (Section 16.1) are based on and were reviewed against the Westinghouse Standard Technical Specifications, which incorporated the requirements of the bulletins for the TMI Action Plan.

II.K.1(17) Trip PZR Level Bistable So That Low Pressure Will Initiate Safety Injection

Discussion:

This item required operating licensees and operating license applicants with Westinghouse designed nuclear steam supply systems to trip the pressurizer level bistable so that the pressurizer low pressure (rather than the pressurizer low pressure and pressurizer low level coincidence) would initiate safety injection.

AP1000 Response:

This issue does not apply to AP1000. The AP1000 does not rely on coincident low pressurizer pressure and low pressurizer level for actuation. See Section 6.3 for a discussion of actuation of the passive core cooling system.

II.K.1(24) Perform LOCA Analyses for a Range of Small-Break Sizes and a Range of Time Lapses Between Reactor Trip and Reactor Coolant Pump Trip

Discussion:

This item requires analyses to provide the basis for the comparison of analytical methods.

AP1000 Response:

The analyses documented in Chapter 15 cover a range of small break sizes. The AP1000 automatically trips the reactor coolant pump on an SI signal. The need to look at time lapses between reactor trip and pump trip is not required.

II.K.3(5) Automatic Trip of Reactor Coolant Pumps

Discussion:

This item requires that operating plants and operating plant applicants study the need for automatic trip of reactor coolant pumps and to modify procedures of designs as appropriate.

AP1000 Response:

The AP1000 design provides for an automatic trip of the reactor coolant pumps on actuation of the passive core cooling system. This trip is provided to prevent reactor coolant pump interaction with the operation of the core makeup tank. See Section 6.3 for additional information.

II.K.3(9) Proportional Integral Derivative Controller Modification

Discussion:

TMI action plan item II.K.3(9) required all Westinghouse plants to raise the interlock bistable trip setting to preclude derivative action from opening the PORVs.

AP1000 Response:

This issue is not applicable to the AP1000. The AP1000 does not include power-operated relief valves. See subsections 5.1.2 and 5.2.2 for additional information.

1.9.4.2.2 Task Action Plan Items

A-1 Water Hammer

Discussion:

Generic Safety Issue A-1 was raised after the occurrence of various incidents of water hammer that involved steam generator feedrings and piping, emergency core cooling systems, residual heat removal systems, containment spray, service water, feedwater, and steam lines. The incidents have been attributed to such causes as rapid condensation of steam pockets, steam-driven slugs of water, pump startup with partially empty lines, and rapid valve motion. Most of the damage has been relatively minor and involved pipe hangers and restraints. However, several incidents have resulted in piping and valve damage. This item was originally identified in NUREG-0371, (Reference 4) and was later determined to be an Unresolved Safety Issue.

AP1000 Response:

Specific sections of the Standard Review Plan (NUREG-0800) address criteria for mitigation of water hammer concerns. The applicable Standard Review Plan sections as well as information provided in NUREG-0927 (Reference 5) were reviewed. The AP1000 meets the water hammer provisions as specified. The discussion that follows provides a brief description of selected systems identified as being subject to water hammer occurrences and special design features that mitigate or prevent water hammer damage.

Design features are incorporated as appropriate to prevent water hammer damage in applicable systems including steam generator feedrings and piping, passive core cooling system, passive residual heat removal system, service water system, feedwater system, and steam lines.

Water hammer issues are considered in the design of the AP1000 passive core cooling system. The passive core cooling system design includes a number of design features specifically to prevent or mitigate water hammer.

The automatic depressurization system operation uses multiple, sequenced valve stages to provide a relatively slow, controlled depressurization of the reactor coolant system, which helps to reduce the potential for water hammer.

Once the depressurization is complete, gravity injection from the in-containment refueling water storage tank is initiated by opening squib valves and then check valves, which reposition slowly. Gravity injection flow actuates slowly, without water hammer, as the pressure differential across the gravity injection check valves equalizes, and the valves open and initiate flow.

The passive residual heat removal heat exchanger is normally aligned with an open inlet valve and closed discharge valves. This alignment keeps the system piping at reactor coolant system pressure, preventing water hammer upon initiation of flow through the heat exchanger. Instrumentation is provided at the system high point to detect a void in the system.

The core makeup tanks are normally aligned with an open inlet line from the reactor coolant cold leg to keep the tanks at reactor coolant system pressure. This alignment keeps the system piping at

reactor coolant pressure, preventing water hammer upon initiation of flow through the tank. In addition, instrumentation is provided at each high point to detect voids within the system. Section 6.3 of the DCD provides additional information on the passive core cooling system.

The potential for water hammer in the feedwater line is minimized by the improved design and operation of the feedwater delivery system. The steam generator features include introducing feedwater into the steam generator at an elevation above the top of the tube bundles and below the normal water level by a top discharge spray tube feedring. The feedring is welded to the feedwater nozzle to limit the potential for inadvertent draining. The layout of the feedwater line is consistent with industry standard recommendations to reduce the potential of a steam generator water hammer.

The startup feedwater system is a nonsafety-related system that provides feedwater during normal plant startup, shutdown, and hot standby. The startup feedwater line is separate from the main feedwater line and therefore does not contribute to the potential of water hammer in the feedwater piping or steam generator feedring.

The main steam line drains are designed to remove accumulated condensate from the main steam lines and to maintain the turbine bypass header at operating temperature during plant operation. The system is designed to accommodate drain flows during startup, shutdown, transient, and normal operation to protect the turbine and the turbine bypass valves from water slug damage.

A-2 Asymmetric Blowdown Loads on Reactor Primary Coolant Systems

Discussion:

Generic Safety Issue A-2 pertains to asymmetric loadings that could act on a pressurized water reactor's primary system as the result of a postulated double-ended rupture of the piping in the primary coolant system. The magnitude of these loads is potentially large enough to damage the supports of the reactor vessel, the reactor internals, and other primary components of the system. Therefore, the NRC initiated a generic study to develop criteria for an evaluation of the response of the primary systems in pressurized water reactors to these loads.

AP1000 Response:

The use of mechanistic pipe break criteria permits elimination of the evaluation of dynamic effects of sudden circumferential and longitudinal pipe breaks in the structural analysis of structures, systems, and components. General Design Criterion 4 allows the use of analyses to eliminate from the design basis the dynamic effects of pipe ruptures postulated at locations defined in subsection 3.6.2. Dynamic effects include jet impingement, pipe whip, jet reaction forces on other portions of the piping and components, subcompartment pressurization including reactor cavity asymmetric pressurization transients, and traveling pressure waves from the depressurization of the system.

The AP1000 reactor coolant loop and pressurizer surge line are designed in accordance with mechanistic pipe break criteria. In addition, other high energy ASME Code, Section III, Class 1 and 2 piping of 6 inches and greater nominal diameter is evaluated against leak-before-break criteria. The evaluation methodology is described in subsection 3.6.3 and Appendix 3B.

A-3 Steam Generator Tube Integrity

Discussion:

Pressurized water reactor steam generator tube integrity is subject to various degradation mechanisms, including corrosion-induced wastage, cracking, reduction in tube diameter, denting, (which leads to primary side stress corrosion cracking), vibration-induced fatigue cracks, and wear or fretting due to loose parts in the secondary system. The primary concern is the capability of degraded tubes to maintain their integrity during normal operation and under accident conditions (LOCA or a main steam line break) with adequate safety margins.

Steam generator tube integrity concerns for the three steam generator suppliers, Westinghouse, Combustion Engineering, and Babcock and Wilcox, are addressed by an integrated NRC program for Generic Safety Issues A3, A4, and A5. This program addresses the areas of steam generator integrity, plant systems response, human factors, radiological consequences, and the response of various organizations to a steam generator tube rupture.

AP1000 Response:

The AP1000 steam generators are designed in accordance with the recommendations of Generic Letter 85-02 and NUREG-0844 (References 6 and 7). The AP1000 steam generator is equipped with a number of features to enhance steam generator tube performance and reliability. These features are described in subsection 5.4.2.

A-9 Anticipated Transients Without Scram

Discussion:

Generic Safety Issue A-9 was resolved with the publication of 10 CFR 50.62. This regulation sets forth the requirements for reduction of risks from anticipated transients without scram.

AP1000 Response:

The AP1000 complies with the requirements of 10 CFR 50.62 except that the AP1000 does not have a safety-related auxiliary feedwater system. In lieu of the automatic initiation of the auxiliary feedwater system under conditions indicative of an ATWS as required by 10 CFR 50.62 (c)(1), the AP1000 automatically initiates the passive residual heat removal system as discussed in Section 6.3.

A discussion of the AP1000 design features used to address the probability of an ATWS is presented in subsection 1.9.5 and Section 7.7.

A-11 Reactor Vessel Materials Toughness

Discussion:

Generic Issue A-11 addresses a concern with the reduction of reactor vessel fracture toughness as plants accumulate more and more service time. 10 CFR 50, Appendix G provides requirements for reactor vessel material toughness.

AP1000 Response:

The AP1000 reactor vessel design complies with the requirements of 10 CFR 50, Appendix G and includes numerous features to reduce neutron fluence, enhance material toughness at low temperature and eliminate weld seams in critical areas. Material requirements are provided in subsection 5.3.2. Pressure and temperature limits are provided in subsection 5.3.3.

A-12 Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports

Discussion:

Generic Safety Issue A-12 addresses a concern with the potential for lamellar tearing of steam generator and RCP support material. NUREG-0577 (Reference 8) categorizes operating plants relative to the adequacy of the plant's steam generator and reactor coolant pump supports with respect to fracture toughness.

AP1000 Response:

The steam generator and reactor coolant pump supports are described in subsection 5.4.10. The supports are designed in accordance with subsection NF of Section III of the ASME Code. Design and fabrication of these supports in accordance with Subsection NF requirements provide acceptable fracture toughness of materials, and conform with NUREG-0577.

A-13 Snubber Operability Assurance

Discussion:

Generic Issue A-13 addresses snubber operability concerns. Snubbers are utilized primarily as seismic and pipe whip restraints at nuclear power plants. Their safety function is to operate as rigid supports for restraining the motion of attached systems or components under rapidly applied load conditions such as earthquakes, pipe breaks, and severe hydraulic transients.

Operating experience reports show that a substantial number of snubbers have leaked hydraulic fluid and that the rejection rate from functional testing and inspection is high. This has led to an NRC and ACRS concern regarding the effect of snubber malfunctions on plant safety.

AP1000 Response:

The use of snubbers is minimized in the AP1000. Gapped support devices, leak-before-break considerations, and state-of-the-art piping analysis methods are used to minimize the use of snubbers. Snubbers applied in safety-related applications are constructed to ASME Code, Section III, Subsection NF as discussed in DCD subsection 3.9.3.4.3.

A-17 Systems Interactions in Nuclear Power Plants

Discussion:

This item addresses the potential systems interactions among systems including safety-related and nonsafety-related structures, systems, and components. There can be unintended and unrecognized dependencies among structures, systems, and components. A number of specific types of interactions have been addressed in other generic safety issues and NRC staff activities. These include guidance for inclusion of internal flooding in the IPE program, requirements that address seismically-induced systems interactions, and evaluation of electric power supplies for electric power reliability. NUREG-0933 classifies this item as resolved with no new requirements.

AP1000 Response:

In addition to addressing the specific system interaction guidance mentioned above, the AP1000 was the subject of a systematic evaluation of potential adverse systems interactions documented in WCAP-15992, "AP1000 Adverse Systems Interactions Evaluation Report" (Reference 69).

A-24 Qualification of Class 1E Safety-Related Equipment

Discussion:

Generic Issue A-24 was resolved with the publication of 10 CFR 50.49, prescribing aging and testing for synergistic effects. The NRC has also issued Revision 1 to Regulatory Guide 1.89 for comment. The proposed revision describes a method acceptable to the NRC staff to demonstrate compliance with the requirements of 10 CFR 50.49.

AP1000 Response:

The AP1000 environmental qualification methodology described in Appendix 3D is based on the generic Westinghouse qualification program approved by the NRC. The Westinghouse methodology addresses the requirements of General Design Criteria 4 and 10 CFR 50.49, as well as the guidance of Regulatory Guide 1.89 and IEEE Standard 323-1974. See Appendix 1A and Reference 9.

A-25 Non-Safety Loads on Class 1E Power Sources

Discussion:

Generic Issue A-25 addresses whether nonsafety-related loads should be allowed to share Class 1E power sources with safety-related plant systems. Past regulatory practice has allowed the

connection of nonsafety-related loads in addition to the required safety loads to Class 1E power sources by imposing some restrictions. The purpose of this issue is for the NRC to determine whether the reliability of the Class 1E power sources is significantly affected by the sharing of safety and nonsafety-related loads.

The NRC considers this issue as technically resolved with the issuance of Revision 2 to Regulatory Guide 1.75. This regulatory guide includes special requirements for connection of nonsafety-related loads to a Class 1E source.

AP1000 Response:

The AP1000 conforms with the criteria of Regulatory Guide 1.75 with minor exceptions (see Appendix 1A and IEEE 384-1974). The AP1000 safety-related power source is the Class 1E dc and UPS system, which supplies power to the ac inverters for the plant instrumentation and control systems. The system also provides power to dc loads associated with the four protection channels and the accident monitoring system. Non-Class 1E loads powered from Class 1E sources are limited to loads that need connection to a reliable power source. No Credible failure of non-Class 1E equipment or systems will degrade the Class 1E system below an acceptable level. Subsection 8.3.2.1.1 provides a discussion on the Class 1E power source.

A-26 Reactor Vessel Pressure Transient Protection

Discussion:

Generic Issue A-26 addresses the need to provide reactor vessel overpressure protection whenever plants are in a cold shutdown condition. Branch Technical Position RSB 5-2 establishes the current NRC criteria for a low-temperature overpressurization protection system.

AP1000 Response:

The AP1000 conforms with the criteria established in Branch Technical Position RSB 5-2. The AP1000 pressurizer is sized to accommodate most pressure transients. Overpressure protection for the reactor coolant system is provided by either the pressurizer safety valves or the normal residual heat removal relief valves, as described in subsection 5.2.2.

A-28 Increase in Spent Fuel Pool Storage Capacity

Discussion:

Generic Issue A-28 addresses the safety significance of damage to spent fuel, primarily from a lack of adequate cooling, that could result in the release of radioactivity.

AP1000 Response:

The AP1000 incorporates the NRC criteria. The heat load is evaluated for the spent fuel storage capacity.

A-29 Nuclear Power Plant Design for the Reduction of Vulnerability to Industrial Sabotage

Description

This item addresses potential methods to reduce vulnerability to sabotage. The NRC staff concluded that existing requirements dealing with plant physical security, controlled access to vital areas, screening for reliable personnel appear to be effective. This item was resolved with no new requirements.

AP1000 Response:

The passive systems in the AP1000 provided to mitigate the effects of potential accidents may have an inherent advantage when considering potential acts of sabotage compared to the active systems in operating plants. The AP1000 includes provisions for access control to the vital area. The provisions for security are discussed in the AP1000 Security Design Report and outlined in Section 13.6.

A-31 Residual Heat Removal Requirements

Discussion:

Generic Issue A-31 addresses the desire for plants to be able to go from hot-standby to cold-shutdown conditions (when this is determined to be the safest course of action) under an accident condition. The safe shutdown of a nuclear power plant following an accident not related to a loss-of-coolant accident has been typically interpreted as achieving a hot standby condition (the reactor is shut down, but system temperature and pressure are at or near normal operating values). There are events that require eventual cooldown and long-term cooling to perform inspection and repairs.

AP1000 Response:

The AP1000 employs safety-related core decay heat removal systems that establish and maintain the plant in a safe shutdown condition following design basis events. It is not necessary that these passive systems achieve cold shutdown as defined by Regulatory Guide 1.139.

The AP1000 complies with General Design Criteria 34 by using a more reliable and simplified system design. The passive core cooling system is employed for both hot-standby and long-term cooling modes. Hot-standby conditions are achieved immediately and a temperature of 420°F is reached within 36 hours. Reactor pressure is controlled and can be reduced to about 250 psig. The passive residual heat removal system provides a closed cooling system to maintain long-term core cooling. Passive feed and bleed cooling, using the passive injection features for the feed and the automatic depressurization system for bleed, provides another closed-loop safety-related cooling capability. This capability eliminates dependency on open-loop cooling systems, which have limited ability to remain in hot standby for long-term core cooling. See Section 7.4 for a discussion of safe shutdown and Section 6.3 for a description of the passive core cooling system.

Since the passive core cooling system maintains safe conditions indefinitely, cold shutdown is necessary only to gain access to the reactor coolant system for inspection or repair. On the

AP1000, cold shutdown is accomplished by using nonsafety-related systems. These systems are highly reliable. They have similar redundancy as current generation safety-related systems and are supplied with ac power from either onsite or offsite sources. See subsection 5.4.7 for a description of the normal residual heat removal system and subsection 7.4.1.2 for a discussion of cold shutdown achieved by use of nonsafety-related systems.

A-35 Adequacy of Offsite Power Systems

Discussion:

Generic Issue A-35 addresses the susceptibility of safety-related electric equipment to offsite power source degradation. The NRC considers this issue as technically resolved with the issuance of the Standard Review Plan, Section 8.3.1 criteria specified in Appendix A, Branch Technical Position BTP PSB 1, "Adequacy of Station Electric Distribution System Voltages."

AP1000 Response:

The AP1000 ac power system is discussed in subsections 8.1 through 8.3. The AP1000 does not require any ac power source to achieve and maintain safe shutdown.

A-36 Control of Heavy Loads Near Spent Fuel

Discussion:

Generic Issue A-36 addresses the need to review requirements, facility designs, and Technical Specifications regarding the movement of heavy loads near spent fuel. The NRC has documented its technical position on this issue in NUREG-0612 (Reference 10) and that issued Standard Review Plan, Section 9.1.5, which includes NUREG-0612 as a part of the review plan.

AP1000 Response:

The AP1000 design conforms to NUREG-0612 and Standard Review Plan, Section 9.1.5. Light load handling systems are described in subsection 9.1.4, and overhead heavy-load handling systems are described in subsection 9.1.5.

A-39 Determination of Safety Relief Valve Pool Dynamic Loads and Temperature Limits for BWR Containments

Discussion:

Generic Issue A-39 addresses operation of BWR primary system pressure relief valves whose operation can result in hydrodynamic loads on the suppression pool retaining structures or those structures located within the pool. These loads result from initial vent clearing of relief valve piping and steam quenching due to high local pool temperatures. This USI was resolved with the issuance of SRP Section 6.2.1.1.C and a series of NUREG reports.

Generic Issue A-39 is not directly applicable to the AP1000. However, the AP1000 in-containment refueling water storage tank (IRWST) has some functional similarity to a suppression pool when the automatic depressurization system (ADS) is actuated.

AP1000 Response:

The AP1000 in-containment refueling water storage tank design includes consideration of loads due to automatic depressurization system operation. The effect of hydrodynamic loads is addressed in DCD subsection 3.8.3.4.2.

A-40 Seismic Design Criteria - Short Term Program

Discussion:

Generic Issue A-40 addresses a desire to identify and quantify conservatism in the seismic design process. The Standard Review Plan, Section 3.7 provides clarification of development of site-specific spectra, justification for use of single synthetic time-history by power spectral density function, location and reductions of input ground motion for soil-structure interaction, and design of above-ground vertical tanks. The revised provisions are used for margin studies and re-evaluations or individual plant examination for external events.

AP1000 Response:

The AP1000 conforms to the criteria outlined in the Standard Review Plan, Section 3.7. The seismic design criteria and seismic evaluation methodology are described in Section 3.7.

The AP1000 employs generic, enveloping seismic design criteria and applies established seismic evaluation methodology that complies with current regulations and regulatory guidance. For sites having specific characteristics outside the range of the selected parameters, the AP1000 is evaluated to demonstrate acceptability to the site-specific characteristics.

A-43 Containment Emergency Sump Performance

Discussion:

Generic Issue A-43 addresses technical concerns as follows:

- Pressurized water reactor sump (or boiling water reactor residual heat removal system suction intake) hydraulic performance under post-loss-of-coolant accident adverse conditions resulting from potential vortex formation, air ingestion, and subsequent pump failure

- The possible transport of large quantities of insulation debris generated by a loss-of-coolant accident resulting from a pipe break to the sump debris screen(s), and the potential for sump screen (or suction strainer) blockage to reduce net positive suction head (NPSH) margin below that required for the recirculation pumps to maintain long-term cooling

- The capability of residual heat removal and containment spray system pumps to continue pumping when subjected to possible air, debris, or other effects, such as particulate ingestion on pump seal and bearing systems

AP1000 Response:

Air ingestion, vortexing, and debris blockage are not significant concerns for the AP1000. Containment recirculation includes sump screens that conform to the criteria specified in Regulatory Guide 1.82. The recirculation screens have a large cross-sectional area to reduce the fluid flow velocity through the screen and to provide a large screening area to accommodate accumulated debris. Horizontal plates located above the recirculation screens preclude debris being deposited in the water directly adjacent to the screens. Pipe subject of loss of coolant pipe breaks and in the vicinity of these breaks use reflective metallic insulation to preclude the generation of fiberous insulation debris. See subsection 6.3.2.2.7. for additional information on the design of the screens and limits on use of fiberous insulation.

Since the AP1000 design does not use pumps to provide safety injection flow, the passive core cooling system injection flow rates are substantially lower than those for plants with pumped injection flow. This results in lower fluid flow velocities through the screens, reducing the potential to draw debris into the sump screens.

The containment recirculation sump piping inlet is located slightly above the compartment floor, which is substantially below the expected flood-up water level. This precludes air ingestion in the piping since recirculation does not initiate until the flood-up water level is well above the piping inlet.

The elimination of pumps also eliminates concerns about the effects on safety injection capability for vortexing, air ingestion, and blockage effects on pump net positive suction head.

The AP1000 includes the capability to use non-safety-related normal residual heat removal pumps to take a suction from the containment recirculation sump to provide reactor coolant system injection. The sump screen design addresses concerns with screen debris, vortexing, and air ingestion.

Section 6.3 provides additional information on the operation of the passive core cooling system. Appendix 1A describes conformance with Regulatory Guide 1.82. Section 6.2 provides additional information on the containment recirculation sump.

A-44 Station Blackout

Discussion:

Generic Issue A-44 was resolved with the publication of 10 CFR 50.63, which provides requirements that light-water-cooled nuclear power plants be able to withstand for a specified duration and recover from a station blackout. It specifies that an alternate ac power source constitutes acceptable capability to withstand station blackout provided an analysis is performed that demonstrates that the plant has this capability from the onset of the station blackout until the alternate ac source(s) and required shutdown equipment are started and lined up to operate.

10 CFR 50.2 for the alternate ac source notes that the alternate ac power source must have sufficient capability and reliability for operation of all systems required for coping with station blackout for the time required to place and maintain the plant in safe shutdown.

AP1000 Response:

AC electrical power is not needed to establish or maintain a plant safe shutdown condition for the AP1000. The ac power system is discussed in Chapter 8. In addition, two nonsafety-related standby diesel generators are provided as alternate sources of electrical power to nonsafety-related active systems that provide a defense-in-depth function.

A-46 Seismic Qualification of Equipment in Operating Plants

Discussion:

Generic Issue A-46 addresses the variability among operating plants in the margins of safety provided in equipment to resist seismically induced loads and perform the intended safety functions. The NRC believes that the seismic qualification of equipment in operating plants must, therefore, be reassessed to confirm the ability to bring the plant to a safe shutdown condition when it is subject to a seismic event.

AP1000 Response:

This issue applies to operating plants and, as such, does not specifically apply to the AP1000, which is designed in accordance with current seismic requirements. The seismic Category I mechanical and electrical equipment utilized for the AP1000 is qualified in accordance with the AP1000 qualification methodology discussed in Section 3.10. The methodology is based on the generic Westinghouse qualification program previously approved by the NRC. This methodology addresses IEEE Standard 344-1987 (Reference 13) and Regulatory Guide 1.100. See subsection 1.9.1 (Appendix 1A).

A-47 Safety Implications of Control Systems

Discussion:

Generic Issue A-47 addresses the safety impact of non-safety-related control systems on plant dynamics. Instrumentation and control systems used by nuclear plants comprise safety-related

protection systems and nonsafety-related control systems. Safety-related systems are used to trip the reactor when specified parameters exceed allowable limits and to protect the core from overheating by initiating emergency core cooling systems. Nonsafety-related control systems are used to maintain the plant within prescribed parameters during shutdown, startup, normal load, and varying power operation. Nonsafety-related systems are not relied on to perform any safety functions during or following postulated accidents, but are used to control plant processes.

AP1000 Response:

For the AP1000, control system failures are considered as potential initiating events. The analyses of these transients demonstrate that the consequences of such failures are bounded by ANS Condition II criteria. No design basis failure of a control system violates Condition II criteria.

The integrated control system for the AP1000 obtains certain control input signals from signals used in the integrated protection system. With the integrated control and protection system, functional independence of the control and protection systems is maintained by providing a signal selection device in the control system for those signals used in the protection system. The purpose of the signal selection device is to prevent a failed signal, caused by the failure of a protection channel, from resulting in a control action that could lead to a plant condition requiring that protective action. The signal selection device provides this capability by comparing the redundant signals and automatically eliminating an aberrant signal from use in the control system. This capability exists for bypassed sensors or for sensors whose signals diverge from the expected error tolerance.

The plant control system incorporates design features such as redundancy, automatic testing, and self-diagnostics to prevent challenges to the protection and safety monitoring system. Chapter 7 provides a discussion of the AP1000 instrumentation and controls. The surveillance requirements for the main and startup feedwater control are found in Technical Specifications 3.7.3 and 3.7.7.

A-48 Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment

Discussion:

Generic Issue A-48 addresses postulated light water reactor accidents resulting in a degraded or melted core that could result in the generation and release to the containment of large quantities of hydrogen. One source of hydrogen is from the reaction of the zirconium fuel cladding with the steam at high temperatures. The NRC requires design provisions for handling hydrogen releases associated with rapid reaction of a large portion of fuel cladding (10 CFR 50.44 and 10 CFR 50.34).

AP1000 Response:

The AP1000 design complies with the provisions of draft changes to 10 CFR 50.44 and 10 CFR 50.34 (f). The mechanisms used to monitor and control hydrogen inside containment are discussed in subsection 6.2.4.

A-49 Pressurized Thermal Shock

Discussion:

Generic Issue A-49 addresses transients and accidents postulated to occur in pressurized water reactors that can result in severe overcooling (thermal shock) of the reactor vessel, concurrent with high pressure. In these pressurized thermal shock events, rapid cooling of the reactor vessel internal surface causes a temperature distribution across the reactor vessel wall that produces a thermal stress with maximum tensile stress at the inside surface of the vessel. The magnitude of the thermal stress varies with the rate of change of temperature and is compounded by coincident pressure stresses.

As long as the fracture resistance of the reactor vessel material is relatively high, these events are not expected to cause vessel failure. The fracture resistance of the reactor vessel material decreases with the integrated exposure to fast neutrons. The rate of decrease is dependent on the chemical composition of the vessel wall and weld materials.

AP1000 Response:

The AP1000 complies with the requirements of 10 CFR 50.61. Material requirements and pressure-temperature limits are discussed in subsections 5.3.2 and 5.3.3.

B-5 Ductility of Two-Way Slabs and Shells and Buckling Behavior of Steel Containments

Discussion:

Part I - Ductility of Two-Way Slabs and Shells

Generic Issue B-5 involved a concern over the lack of information on the behavior of two-way reinforced concrete slabs loaded dynamically in biaxial membrane tension, flexure, and shear. The NRC Staff concluded that there is sufficient information pertaining to the design of two-way slabs subjected to dynamic loads and biaxial tension to enable a reasonably accurate analysis.

Part II - Buckling Behavior of Steel Containments

Generic Issue B-5 involves a concern over the lack of a uniform, well defined approach for design evaluation of steel containments. Of particular interest was potential instability of the shell during dynamic loadings. Based on the conclusion of the NRC Staff that existing steel containments had adequate margins against buckling and that the issue of steel containment buckling had very little safety impact, this item was classified as resolved with no new requirements.

AP1000 Response:

The design requirements and analysis methods used for two-way reinforced concrete slabs and for the steel containment are outlined in DCD Section 3.8.

B-17 Criteria for Safety-Related Operator Actions

Discussion:

Generic Issue B-17 addresses the development of a time criterion for safety-related operator actions including a determination of whether or not automatic actuation is required. The evaluation of this issue includes Issue 27, Manual versus Automated Actions.

AP1000 Response:

The AP1000 automatically initiates the safety-related actions required to protect the plant during design basis events. The plant systems are designed to provide the required information to the operator to monitor plant conditions and to evaluate the performance of the safety-related passive systems, as well as the nonsafety-related active systems. The active systems are designed to automatically actuate and provide defense-in-depth for various plant events, to preclude unnecessary actuation of the safety-related passive systems. The plant design also provides the capability for a backup manual initiation of both the safety-related systems and the nonsafety-related defense-in-depth systems.

As described in Chapter 15, the AP1000 safety systems maintain the plant in a safe condition following design basis events. For the design basis events described in Chapter 15, this is accomplished without the need for operator action for up to 72 hours. Operator action is planned and expected during plant events to achieve the most effective plant response consistent with event conditions and equipment availability. For events where operator action is taken, the plant design maximizes the time available to complete actions for events. For example, during a steam generator tube rupture, no operator action is required to establish safe shutdown conditions or prevent steam generator overfill. It is expected that the main control room operators take actions similar to those taken in current plants to identify and isolate the faulted steam generator and to stabilize plant conditions.

For events where operator actions are taken, the AP1000 design is based on previous experience and the guidance of ANSI 58.8-1984 (Reference 21). At least 30 minutes is available following design basis events for the operator to initiate planned actions.

B-22 LWR Fuel

Discussion:

Generic Issue B-22 addresses the reliability of fuel behavior predictions during normal operation and postulated accidents. Standard Review Plan, Section 4.2 provides detailed NRC criteria for the design of fuel and core components.

AP1000 Response:

The AP1000 reactor core design complies with the Standard Review Plan, Section 4.2. See Section 4.2 for a discussion of the fuel system design.

B-29 Effectiveness of Ultimate Heat Sinks

Discussion:

Generic Issue B-29 addresses NRC confirmation of currently used mathematical models for prediction of ultimate heat sink performance by comparing model performance with field data and development of better guidance regarding the criteria for weather record selection to define ultimate heat sink design basis meteorology.

The NRC considers this issue to be technically resolved with the publication of three reports: NUREG-0693, NUREG-0733, and NUREG-0858 (References 23, 24 and 25).

AP1000 Response:

The AP1000 passive containment cooling system complies with Standard Review Plan, Section 9.2.5 by providing passive decay heat removal that transfers heat to the atmosphere, which is the ultimate heat sink for accident conditions. The passive containment cooling system is described in subsection 6.2.2.

B-32 Ice Effects on Safety-Related Water Supplies

Discussion:

Generic Issue B-32 addresses the potential effects of extreme cold weather and ice buildup on the reliability of various plant water supplies. Current NRC criteria are provided in Standard Review Plan, Section 2.4.7, "Ice Effects."

AP1000 Response:

Subsection 6.2.2 describes the ultimate heat sink design and discusses the features that prevent freezing in the passive containment cooling system.

B-36 Develop Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units for Engineered Safety Features Systems and for Normal Ventilation Systems

Discussion:

Generic Issue B-36 addresses the development of revisions to current guidance and technical positions regarding engineered safety features and normal ventilation system air filtration and adsorption units. The NRC considers this issue technically resolved with the issuance of Revision 2 to Regulatory Guide 1.52 and Revision 1 to Regulatory Guide 1.140.

AP1000 Response:

There are no safety-related air filtration systems in the AP1000. The specific functions are outlined in Section 6.4 and subsection 9.4.1. Conformance with Regulatory Guide 1.140 is discussed in Appendix 1A.

B-53 Load Break Switch

Discussion:

Generic Issue B-53 addresses the use of the generator load break switch for isolating the generator from the step-up transformer following turbine trip. Plant designs that utilize generator load circuit breakers to satisfy the requirement for an immediate access circuit stated in General Design Criterion 17, "Electric Power Systems," must prototype-test the generator load circuit breaker to demonstrate functional capability.

AP1000 Response:

The AP1000 design incorporates a generator load circuit breaker to provide a reliable source of ac power to the electrical systems. Exceptions to General Design Criteria 17, as discussed in Section 3.1, are due to the AP1000 design not requiring ac power sources for a design basis accident. Subsection 8.2.2.5 provides further discussion.

B-56 Diesel Reliability

Discussion:

Generic Safety Issue B-56 addresses the reliability of emergency onsite diesel-generators. Diesel reliability is a factor in the criteria associated with the resolution of Unresolved Safety Issue A-44. The resolution of issue B-56 is the development of guidelines for an acceptable emergency diesel-generator reliability program to ensure conformance with the emergency diesel-generator target reliability (0.95 to 0.975) identified in the proposed resolution of Unresolved Safety Issue A-44.

AP1000 Response:

The AP1000 diesel-generators are not safety related. The AP1000 diesel-generator reliability is based on diesel-generator industry standards and practices. The diesel generator is discussed in subsection 8.3.1. The diesel generator reliability is modeled in the PRA. The reliability assurance program is discussed in Section 16.2.

B-61 Allowable ECCS Equipment Outage Periods

Discussion:

Generic Safety Issue B-61 addresses surveillance test intervals and allowable equipment outage periods in the technical specifications for safety-related systems. This task involves the NRC development of analytically based criteria for use in confirming or modifying these surveillance intervals and allowable equipment outage periods.

AP1000 Response:

The AP1000 surveillance test intervals and allowable outage times help to meet plant safety goals while maximizing plant availability and operability. In determining these limits for the AP1000 technical specifications, a combination of NUREG-1431 precedent, system design, and safety-related function is considered.

B-63 Isolation of Low-Pressure Systems Connected to the Reactor Coolant Pressure Boundary

Discussion:

Generic Issue B-63 addresses the adequacy of the isolation of low-pressure systems that are connected to the reactor coolant pressure boundary. The NRC staff requires that valves forming the interface between high- and low-pressure systems associated with the reactor coolant boundary have sufficient redundancy to prevent the low-pressure systems from being subjected to pressures that exceed their design limits.

AP1000 Response:

The AP1000 includes interconnections between high- and low-pressure systems. Each of these systems interfaces contains appropriate isolation provisions. Valves at the interface between high- and low-pressure systems have redundancy to prevent low-pressure systems from being subjected to pressures that exceed their design limits. The AP1000 design meets the provisions of the Standard Review Plan, Section 3.9.6.

The normal residual heat removal system interface is addressed in subsection 5.4.7. WCAP-15993 (Reference 56) provides an evaluation of the AP1000 conformance to intersystem loss-of-coolant accident regulatory criteria.

B-66 Control Room Infiltration Measurements

Discussion:

Generic Safety Issue B-66 addresses the adequacy of control room area ventilation systems and control building layout to ensure that plant operators are adequately protected against the effects of accidental releases of toxic and radioactive gases. The NRC considers this issue as being technically resolved, and criteria have been incorporated in Standard Review Plan, Section 6.4.

AP1000 Response:

The AP1000 main control room is essentially leak-tight. A description of the control room habitability systems is contained in Section 6.4.

Verification of design infiltration rates is as specified in Standard Review Plan, Section 6.4. The AP1000 minimizes unfiltered in-leakage by maintaining the main control room at a slightly positive pressure.

C-1 Assurance of Continuous Long-Term Capability of Hermetic Seals on Instrumentation and Electrical Equipment

Discussion:

Generic Issue C-1 addresses the long-term capability of hermetically sealed instruments and equipment that must function in post-accident environments. The NRC considers this issue as being technically resolved with the issuance of current criteria for qualification of safety-related electrical equipment.

AP1000 Response:

The AP1000 environmental qualification program described in response to Unresolved Safety Issue A-24 addresses qualification of safety-related instrumentation and electrical equipment that must function under accident conditions. This program confirms the integrity of seals employed in the design of Class 1E equipment. See item A-24 of this subsection and Section 3.11 for AP1000 qualification methodology.

C-4 Statistical Methods for ECCS Analysis

Discussion:

Generic Issue C-4 addresses NRC development of a statistical assessment of the certainty level of the peak clad temperature limit. Appendix K, "ECCS Evaluation Models," to 10 CFR 50 specifies the requirements for ECCS analysis. These requirements call for conservatisms to be applied to certain models and assumptions used in the analysis to account for data uncertainties at the time Appendix K was written. The resulting conservatism in the calculated peak clad temperature (PCT) has not been thoroughly compared against the uncertainty in peak clad temperature obtained from a realistically calculated (best-estimate) LOCA. The staff allows voluntary use of statistical uncertainty analysis to justify relaxation of all but the required conservatisms contained in current ECCS evaluation models.

AP1000 Response:

Chapter 15 discusses the LOCA analysis for the AP1000.

C-5 Decay Heat Update

Discussion:

Generic Issue C-5 involves following the work of research groups in determining best-estimate decay heat data and associated uncertainties for use in LOCA calculations.

The staff has determined that the 1979 ANSI 5.1 is technically acceptable and has allowed the use of this data to justify relaxation of non-required conservatisms in current ECCS evaluation models. The ECCS rule change allows the use of this new data. This issue was determined to be resolved.

AP1000 Response:

The large-break LOCA analyses for the AP1000, which employ the best-estimate W COBRA/TRAC analysis methodology (subsection 15.6.5), use the decay heat model identified in the 1979 ANSI 5.1 (Reference 26).

C-6 LOCA Heat Sources

Discussion:

Generic Issue C-6 addresses the impact on LOCA calculations of LOCA heat sources, their associated uncertainties, and the manner in which they are combined. An evaluation was made of the combined effect of power density, decay heat, stored energy, fission power decay, and their associated uncertainties with regard to calculations of LOCA heat sources.

AP1000 Response:

See subsection 15.6.5 for a discussion of LOCA heat sources.

C-10 Effective Operation of Containment Sprays in a LOCA

Discussion:

Generic Issue C-10 addresses the effectiveness of containment sprays to remove airborne radioactive materials that could be present within the containment following a LOCA. The NRC considers this issue as being technically resolved with the issuance of ANSI 56.5-1979 (Reference 28), which is referenced in Standard Review Plan, Section 6.5.2.

AP1000 Response:

The AP1000 design does not employ a safety-related containment spray system for removal of airborne radioactive materials in containment. Subsection 15.6.5.3 provides details of source term and mitigation techniques.

C-17 Interim Acceptance Criteria for Solidification Agents for Radioactive Solid Wastes

Discussion:

Generic Issue C-17 addresses the development of criteria for acceptability of radwaste solidification agents. The NRC considers this issue as technically resolved with the issuance of 10 CFR 61.56.

AP1000 Response:

The AP1000 solid radwaste system transfers, stores, and prepares spent ion exchange resins for disposal. It also provides for disposal of filter elements; sorting, shredding, and compaction of compressible dry active wastes. The solid radwaste system does not provide for liquid waste

concentration or solidification. These functions, if used, are provided using mobile systems. Solidification of wastes is not performed by permanently installed systems.

1.9.4.2.3 New Generic Issues

These items were identified in NUREG-0933 as New Generic Issues and surfaced after the publication of the NUREGs that included the Task Action Plan items other unresolved safety issues.

Issue 14 PWR Pipe Cracks

Discussion:

This issue addresses the occurrences of main feedwater line cracking found in operating plants. This issue was classified as resolved with no new requirements.

AP1000 Response:

The design and inspection requirements for the feedwater lines are discussed in subsection 10.4.7.

Issue 15 Radiation Effects on Reactor Vessel Supports

Discussion:

Generic Safety Issue 15 addresses the potential problem of radiation embrittlement of reactor vessel support structures. There is a potential for radiation embrittlement of the reactor vessel support structure from long-term exposure to neutrons with an energy of 1 MeV or greater. Embrittlement due to neutron damage may increase the potential for propagation of existing flaws.

AP1000 Response:

The supports for the AP1000 reactor pressure vessel are designed for loading conditions and environmental factors including consideration of neutron fluence levels. The material requirements include fracture toughness requirements and impact testing requirements in compliance with ASME Code, Section III, Subsection NF requirements. The reactor pressure vessel supports are not in the region of high neutron fluence where neutron embrittlement of the supports would be a significant concern.

Issue 22 Inadvertent Boron Dilution Event

Discussion:

Some operating plants do not have provisions to detect boron dilution during cold shutdown. This could result in inadvertent criticality. The NRC staff concluded that existing review criteria are adequate. This issue was classified as resolved with no new requirements.

AP1000 Response:

The provisions in the design to preclude inadvertent boron dilution events are outlined in DCD subsection 9.3.6.

Issue 23 Reactor Coolant Pump Seal Failures

Discussion:

Generic Safety Issue 23 addresses reactor coolant pump seal failures that challenge the makeup capacity in PWRs. Such seal failures represent small-break loss-of-coolant accidents.

AP1000 Response:

The AP1000 reactor coolant pumps are canned motor pumps. A canned motor pump contains the motor and all rotating components inside a pressure vessel designed for full reactor coolant system pressure. The shaft for the impeller and rotor is contained within the pressure boundary; therefore, seals are not required in order to restrict leakage out of the pump into containment. Subsection 5.4.1 provides additional information on the canned motor pump design for the AP1000 reactor coolant pumps. Since the reactor coolant pumps do not rely on seals as a reactor coolant pressure boundary, this issue is not applicable to the AP1000.

Issue 24 Automatic ECCS Switchover to Recirculation

Discussion:

This issue addresses the issue of switchover from safety injection to recirculation using manual valve alignment or automatic valve alignment.

AP1000 Response:

The AP1000 does not switch from injection to recirculation in the sense that injection is not isolated when recirculation is opened. The AP1000 does provide for automatic opening of the recirculation line on a low level signal from the in-containment refueling water storage tank. See Section 6.3 for additional details.

Issue 29 Bolting Degradation or Failure in Nuclear Power Plants

Discussion:

Generic Safety Issue 29 addresses a concern about pressure boundary integrity and component support reliability associated with bolt failures.

As documented in Generic Letter 91-17, the NRC has provided resolution of this issue. The resolution is documented in NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," and NUREG-1445, "Regulatory Analysis for the Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants." The resolution was based on a number of industry initiatives and NRC staff actions. NRC staff

actions include issuing a number of bolting-related bulletins, generic letters and information notices. Industry initiatives include the publishing of EPRI Reports NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," and NP-5067, "Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel."

EPRI Report NP-5769 establishes the characteristic that bolted connections exhibit leakage prior to failure resulting from bolt degradation. The NRC has endorsed the recommendation in NP-5769 that plant-specific bolting integrity programs be established that encompass safety-related bolting. NUREG-1339 includes recommendations and guidelines for the content of a comprehensive bolting integrity program.

AP1000 Response:

The elements of resolution pertain to the design, material selection, fabrication, and in-service inspection of the bolted connections found in the AP1000. To address this, resolutions found in NUREG-1339 are incorporated into the design, material selection, fabrication, and maintenance of the bolted connections. The maintenance practices are addressed by the maintenance program of the combined license holder. Conformance to ASME Code, Section III requirements for pressure boundary components and related supports provides safe operation in the event of bolting degradation. Because of the emphasis in the AP1000 design on access for maintenance and inspection, the recommended maintenance practices can be implemented.

Issue 43 Reliability of Air Systems

Discussion:

This issue addresses the concern that compressed air system degradation or malfunction may cause malfunction of safety-related systems and components. Of particular interest are air operated valves because of problems with the quality of the air supply or the manner in which the compressed air system fails. Generic Letter 88-14 and NUREG-1275 were issued in response to this issue.

AP1000 Response:

The compressed air systems are described in subsection 9.3.1. Provisions are included to maintain the quality of the air supply. The AP1000 safety-related, air-operated valves do not rely on the air supply to perform their safety-related function.

Issue 45 Inoperability of Instrumentation Due to Extreme Cold Weather

Discussion:

Generic Safety Issue 45 addresses the inoperability of instrumentation due to extreme cold weather. This issue was resolved with the issuance of changes to Standard Review Plan, Section 7.1, Appendix A to Section 7.1, Section 7.5, and Section 7.7.

AP1000 Response:

The AP1000 complies with Standard Review Plan Section 7.1, Appendix A to Section 7.1, Section 7.5, and Section 7.7.

Issue 51 Proposed Requirements for Improving the Reliability of Open Cycle Service Water Systems

Discussion:

Generic Safety Issue 51 addresses the susceptibility of open cycle service water systems to fouling including the buildup of aquatic bivalves and corrosion products that can significantly degrade the performance of the system. In operating plants, the service water system is typically used to cool safety-related equipment and to transfer decay heat to the ultimate heat sink.

AP1000 Response:

The service water system in the AP1000 provides cooling water to the component cooling water system and has no safety-related functions. None of the safety-related equipment requires cooling water to effect a safe shutdown or mitigate the effects of design basis events. Heat transfer to the ultimate heat sink is accomplished by heat transfer through the containment shell to air and water flowing on the outside of the shell.

The design of the service water system and the provisions for minimizing long-tern corrosion and organic fouling are described in subsection 9.2.1.

Issue 57 Effects of Fire Protection System Actuation

Discussion:

Generic Safety Issue 57 addresses the potential for adverse interactions from actuation of the fire protection system with safety-related equipment. Operating experience has shown that safety-related equipment subject to fire protection system water spray and other suppressant chemicals can be rendered inoperable.

AP1000 Response:

The fire protection system and fire protection program in the AP1000 minimize the potential for adverse interactions of safety-related equipment with the fire protection system. The means used to achieve this result include: isolating combustible material and limiting the spread of fire by subdividing the plant into fire areas separated by fire barriers, providing separate and redundant safe shut down components and associated electrical divisions to preserve the ability to safely shutdown the plant following a fire, and providing floor drains sized to remove expected firefighting water without flooding safety-related equipment. The design of the fire protection system is described in subsection 9.5.1.

Issue 67.3.3 Improved Accident Monitoring

Discussion:

This issue addresses weaknesses in accident monitoring. The recommended solution is to implement Regulatory Guide 1.97.

AP1000 Response:

The guidance of Regulatory Guide 1.97 is followed to determine the appropriate parameters to monitor in the AP1000.

Issue 73 Detached Thermal Sleeves

Discussion:

This issue addresses problems with "generation 3" thermal sleeves.

AP1000 Response:

The AP1000 does not use generation 3 thermal sleeves and includes design provisions to preclude failures of thermal sleeves.

Issue 75 Generic Implications of ATWS Events at the Salem Nuclear Plant

Discussion:

This issue considers the failure of reactor trip breakers to open and issues related to design and testing of the reactor protection system. Issues to be considered include the capability to record and display reactor trip system parameters, equipment classification information, post-maintenance testing, and reliability improvements in operating plants. Generic letter 83-28 and IE Bulletins 83-01 and 83-04 were issued by the staff with specific requirements.

AP1000 Response

The design of the reactor trip breakers and the reactor protection system is outlined in Section 7.1. Information on the functional requirements for reactor trip and conformance with industry and regulatory guidance is outlined in Section 7.2.

The provisions provided to display and record parameters used by the reactor trip system are outlined in subsections 7.1.2.6 and 7.1.2.13. Section 7.5 also provides information on requirements for safety-related display information.

Subsection 7.1.1 identifies the safety-related functions provided by the protection and safety monitoring system and the items that are included in the system including the reactor trip switchgear. Conformance of safety-related systems and components to industry and regulatory criteria is identified in subsection 7.1.4.

The reliability and fault tolerance of the protection and safety monitoring system for test maintenance and bypass conditions are outlined in subsection 7.1.2.10.

The changes in the design of the reactor trip breakers and associated logic to enhance reliability in operating nuclear power plants have been incorporated in the AP1000 design as appropriate. The reactor trip system includes built-in test capability.

WCAP-17800 addresses conformance with generic letters and bulletins.

Issue 79 Unanalyzed Reactor Vessel Thermal Stress During Natural Convection Cooldown

Discussion:

Generic Safety Issue 79 addresses the thermal stresses that occur in the reactor vessel head flange during a natural circulation cooldown. High stresses in the flange or studs during a natural circulation cooldown in PWRs could violate ASME code allowables. Cycling of the stresses could reduce the fatigue margin. Generic Letter 92-02 repeated the reporting requirements of 10CFR 50.73 (a)(2)(ii)(B), "Licensee event report system".

AP1000 Response:

The natural circulation cooldown transient is evaluated as part of ASME Code vessel evaluations and is discussed in Subsection 3.9.1.1.2.11. The procedures to address the requirements of 10CFR 50.73 (a)(2)(ii)(B) referenced in Generic Letter 92-02 are the responsibility of the Combined License Applicant.

Issue 82 Beyond Design Basis Accidents in Spent Fuel Pools

Discussion:

This issue addresses the concern of a beyond design basis accident in which the spent fuel pool is drained and spent fuel stored there subsequently catches on fire releasing very large amounts of radioactive contamination. This issue is classified as resolved with no new requirements.

AP1000 Response:

The AP1000 includes design provisions that preclude draining of the spent fuel pool. Also, provisions are available to supply water to the pool in the event the water covering the spent fuel begins to boil off.

Issue 83 Control Room Habitability

Discussion:

Loss of control room habitability following an accidental release of external toxic or radioactive material or smoke can impair or cause loss of the control room operators' capability to safely control the reactor. Use of the remote shutdown workstation outside the control room following

such events is unreliable since this station has no emergency habitability or radiation protection provisions.

AP1000 Response:

Habitability of the main control room is provided by the main control room/technical support center HVAC subsystem of the nonsafety-related nuclear island nonradioactive ventilation system (VBS). If ac power is unavailable for more than 10 minutes or if "high-high" particulate or iodine radioactivity is detected in the main control room supply air duct, which would lead to exceeding General Design Criteria 19 operator dose limits, the protection and safety monitoring system automatically isolates the main control room and operator habitability requirements are then met by the main control room emergency habitability system (VES). The safety-related main control room emergency habitability system supplies breathable quality air for the main control room operators while the main control room is isolated.

In the event of external smoke or radiation release, the nonsafety-related nuclear island nonradioactive ventilation system provides for a supplemental filtration mode of operation, as discussed in Section 9.4. In the unlikely event of a toxic chemical release, the safety-related main control room emergency habitability system has the capability to be manually actuated by the operators. Further, a 6-hour supply of self-contained portable breathing equipment is stored inside the main control room pressure boundary.

Issue 87 Failure of HPCI Steam Line Without Isolation

Discussion:

Generic Safety Issue 87 addresses the uncertainty regarding the operability of the motor-operated isolation valves for the steam supply lines of the high-pressure coolant injection (HPCI) system in boiling water reactors following a postulated break in the supply line. A break in the line could lead to high flow or high differential pressure that may inhibit closure of the isolation valve. These valves typically cannot be tested in-situ for the design flow rates and pressures. Although the AP1000 does not have a high-pressure coolant injection system, it does have isolation valves designed to close against high flow or high pressure differential in the event of a postulated pipe break.

The issue of the operability of motor-operated valves has received considerable attention since Generic Safety Issue 87 was initiated. The NRC provided guidance for inservice testing of motor-operated, safety-related valves in Generic Letter 89-10. SECY-93-087 identifies the proposed position on inservice testing of safety-related valves for advance light water reactors. The guidance in these documents recommends that safety-related valves be tested under full flow under actual plant conditions where practical. EPRI has a program to demonstrate operation of motor-operated valves.

AP1000 Response:

Safety-related valves must meet the requirements of ASME Code, Section III to provide pressure boundary integrity. Valves and valve operators are sized to provide operation under a full range of design basis flow and pressure drop conditions. For the AP1000, safety-related motor-operated

valve designs are subject to qualification testing to demonstrate the capability of the valve to open, close, and seat against maximum pressure differential and flow. The requirements for this testing are based on ANSI B16.41, "Functional Qualification Requirements for Power Operated Active Valve Assemblies for Nuclear Power Plants." See subsection 5.4.8 for an outline of AP1000 valve requirements.

The in-service testing program for safety-related valves is discussed in subsection 3.9.6. Motor-operated valves are to be operability tested as outlined in subsection 3.9.6.2.2. Subsection 3.9.6.2.2 includes a discussion of the factors to be considered to determine which valves and test conditions are to be used for operability testing of power-operated valves. Sufficient flow is provided to fully open check valves during testing unless the maximum accident flows are not sufficient to fully open the check valve. The valves built to ASME Code, Section III are tested in compliance with the requirements found in the ASME code, "Code for Operation and Maintenance of Nuclear Power Plants." For additional information on inservice testing of safety-related valves, see subsection 3.9.6.

Issue 93 Steam Binding of Auxiliary Feedwater Pumps

Discussion:

Generic Safety Issue 93 addresses the potential for a common mode failure of the pumps in an auxiliary or emergency feedwater system. Hot water leaking through one or more isolation valves can flash to steam at the auxiliary feedwater pump potentially resulting in the failure of the pump to operate if required because of steam binding. The NRC addressed this issue in Bulletin 85-01, and reinforced it in Generic Letter 88-03, by requesting that the fluid conditions in the auxiliary feedwater system be monitored and procedures be developed to recognize steam binding and restore the auxiliary feedwater system to operable status if steam binding should occur.

AP1000 Response:

The AP1000 does not have a safety-related auxiliary feedwater system. The passive core cooling system provides the safety-related function of cooling the reactor coolant system in the event of loss of feedwater. The startup feedwater system provides the steam generators with feedwater during plant conditions of startup, hot standby, and cooldown and when the main feedwater pumps are unavailable. The startup feedwater system has no safety-related function.

The startup feedwater system includes temperature instrumentation in the pump discharge for monitoring of the temperature of the startup feedwater system. The system also includes a normally closed isolation valve and a normally closed check valve for each pump limiting potential back leakage.

Issue 94 Additional Low-Temperature Overpressure Protection for Light Water Reactors

Discussion:

Generic Safety Issue 94 addresses the establishment of additional guidance for reactor coolant system low-temperature overpressure protection to ensure reactor vessel and reactor coolant system integrity beyond that identified in the resolution to Generic Safety Issue (GSI) A-26.

Low-pressure overpressurization events that occurred subsequent to the implementation of the guidelines for resolution of GSI A-26 indicated a need for additional low-temperature overpressure protection. To resolve this issue, the NRC issued Generic Letter 90-06 which required a revision to plant technical specifications for operability of the low-temperature overpressure protection system. Other possible solutions identified in GL 90-06 included hardware modifications including use of residual heat removal system relief valves and requiring the low temperature overpressure protection system to be fully safety related.

AP1000 Response:

The reactor vessel for the AP1000 is designed to be less susceptible to brittle fracture during low temperature overpressure events. The material requirements and welding processes are developed to enhance resistance to embrittlement. See subsection 5.3.2 for additional information on the requirements to address fracture toughness of the reactor vessel.

The normal residual heat removal system is designed to provide the safety-related function of low temperature overpressure protection for the reactor coolant system during refueling, startup, and shutdown operations. The system is designed to limit the reactor coolant system pressure within the limits specified in 10 CFR 50, Appendix G. The relief valve in the normal residual heat removal system is used to provide the overpressure protection. See subsection 5.4.7 for additional information on the design of the normal residual heat removal system and the overpressure protection function.

Issue 103 Design for Probable Maximum Precipitation

Discussion:

Generic Safety Issue 103 addresses the methodology used for determining the design flood level for a particular reactor site. This issue was resolved by incorporating the methodology into the Standard Review Plan.

AP1000 Response:

This is a site-related parameter. The AP1000 is designed for air temperatures, humidity, precipitation, snow, wind, and tornado conditions as specified in Table 2.0-1. The Combined License applicant will demonstrate that the site parameters are within the limits specified for the standard design.

The site is acceptable if the site characteristics fall within the AP1000 plant site design parameters in Table 2-1. For cases where a site characteristic exceeds the envelope parameter, it will be necessary for the Combined License applicant referencing the AP1000 to demonstrate that the site characteristic does not exceed the capability of the design. For additional information on the site interface parameters, see Chapter 2.

Issue 105 Interfacing System LOCA at BWRs

Discussion:

Generic Safety Issue 105 addresses concerns over the adequacy of isolation valves between the reactor coolant system and low-pressure interfacing systems in BWRs. This issue, which is limited to pressure isolation valves in BWRs, is related to Generic Safety Issue 96, which considers the failure of the pressure isolation valves between the reactor coolant system and the RHR system in PWRs. Overpressurization of low-pressure piping systems due to reactor coolant system boundary isolation failure could result in rupture of the low-pressure piping outside containment. This may result in a core melt accident with an energetic release outside the containment building that could cause a significant offsite radiation release. Designing interfacing systems to withstand full reactor pressure is an acceptable means of resolving this issue.

AP1000 Response:

For information on this issue, see subsection 1.9.5.1, SECY-90-016 Issues. See subsection 5.4.7 for additional information on the normal residual heat removal system design.

Issue 106 Piping and Use of Highly Combustible Gases in Vital Areas

Discussion:

Generic Safety Issue 106 addresses the normal process system use of relatively small amounts of combustible gases on site and also addresses leaks or breaks in the hydrogen piping and supply system that could result in the accumulation of a combustible or an explosive mixture of air and hydrogen within the auxiliary systems building. The accumulation of combustible or explosive mixtures of gas in the auxiliary systems building could represent a threat to safety-related equipment if the combustible gases are inadvertently ignited.

AP1000 Response:

The AP1000 uses small amounts of combustible gases for normal plant operation. Most of these gases are used in limited quantities and are associated with plant functions or activities that do not jeopardize any safety-related equipment. These gases are found in areas of the plant that are removed from the Nuclear Island (see subsection 9.3.2 for a description of the plant gas system). The exception to this is the hydrogen supply line to the chemical and volume control system (CVS).

The chemical and volume control system is the only system on the nuclear island that uses hydrogen gas. Hydrogen is supplied to the AP1000 CVS inside containment from a single hydrogen bottle. The release of the contents of an entire bottle of hydrogen in the most limiting building volumes (both inside containment and in the auxiliary building) would not result in a volume percent of hydrogen large enough to reach a detonable level.

The chemical and volume control system hydrogen supply piping is routed through the turbine building and into the auxiliary building and then into containment. The H_2 supply line is routed through the piping/valve room on elevation 100′-0″ of the auxiliary building. The piping/valve

penetration room in the auxiliary building on elevation 100′-0″ is designed as a 3-hour fire zone. A fire in this area would not inhibit the safe shutdown of the plant. More information is contained in Appendix 9A.

The turbine building does not house any safety-related systems or equipment. The release of hydrogen into an area of the turbine building does not represent a threat to the safety of the plant.

The AP1000 containment has hydrogen sensors that would detect hydrogen leaks. The containment hydrogen concentration monitoring subsystem is described in Subsection 6.2.4.1.

Issue 113 Dynamic Qualification Testing of Large-Bore Hydraulic Snubbers

Discussion:

Generic Safety Issue 113 addresses the requirements for qualification and periodic operability testing of large bore hydraulic snubber for operating plants. Large-bore hydraulic snubbers are used to a limited extent on the AP1000 to provide support, particularly for seismic events, of piping systems and components while allowing for movement due to thermal expansion. The NRC, in a draft regulatory guide (SC-708-4, "Qualification and Acceptance Test for Snubbers Used in Systems Important to Safety"), has established recommendations for testing of hydraulic snubbers on a forward-fit basis; that is, units without a license at the time the recommendations were established.

AP1000 Response:

The AP1000 plant uses significantly fewer hydraulic snubbers than do currently operating plants. In addition to the recommendations in the draft regulatory guide, testing requirements have been established in ASME OM Code – 1995 Edition up to and including the 1996 Addenda, "Code for Operation and Maintenance of Nuclear Power Plants." Subsection 3.9.3.4.3 discusses requirements for production and qualification testing. The design of the hydraulic snubbers permits required preoperational and inservice testing.

Subsection 3.9.8.3 identifies the requirement for Combined License applicant information on snubber operability testing.

Issue 120 On-Line Testability of Protection System

Discussion:

This issue is related to the protection system of some older plants that do not provide for as complete a degree of on-line protection system testing surveillance capability as is now required. Testing requirements and guidance are found in GDC 21, Regulatory Guides 1.22 and 1.118 and IEEE Standard 338. This item is classified as resolved with no additional requirements.

AP1000 Response:

This item does not apply to the AP1000. The provision for testing of the protection system in conformance with the regulatory guidance is found in Section 7.1.

Issue 121 Hydrogen Control for Large, Dry PWR Containments

Discussion:

Generic Safety Issue 121 concerns ongoing NRC experimental and analytical programs addressing the likelihood of safe shutdown equipment surviving a hydrogen burn. The staff also intends to explore the possibility and probable consequences of the formation of local detonable concentrations in large, dry PWRs. The concerns are prediction of conditions in realistic configurations, and containment and equipment survivability.

AP1000 Response:

The AP1000 includes provisions for hydrogen control for the unlikely severe accident cases in which large amounts of hydrogen could be generated because of degraded core events. Analyses were performed to examine the consequences of hydrogen burn and to evaluate the likelihood of deflagration to detonable transitions.

For severe accident cases, the containment hydrogen control system prevents hydrogen burn initiation at high hydrogen concentration levels. Hydrogen igniters promote burning when the lower flammability limit is reached and limits the containment hydrogen concentration to less than 10 volume percent during and following a degraded core or core melt.

Thus, for severe accident cases, the AP1000 is designed to prevent the occurrence of hydrogen detonation, thereby preventing the possibility of the resultant large pressure spikes in containment, which is the source of concern for containment integrity and equipment survival. Details of the hydrogen ignition subsystem are provided in subsection 6.2.4.2.3. Placement of the hydrogen igniters is discussed in subsection 6.2.4.

A hydrogen burn analysis shows that the AP1000 hydrogen igniter system is effective in maintaining the hydrogen concentration throughout the containment close to the lower flammability limit, and that the peak pressure in the containment during and following hydrogen burn remains well below ASME service level C stress intensity limits. The hydrogen concentration is similar in all compartments analyzed, indicating that the hydrogen released mixes well in the AP1000 containment. The analyses predict conditions in realistic configurations. Peak gas temperatures and pressures in each compartment for each case analyzed are provided, thus providing the hydrogen burn thermal environment that containment equipment will experience. Details are provided in Chapter 14 of the PRA report.

The challenge to the AP1000 containment integrity from hydrogen deflagrations and detonations during core damage events is examined in the hydrogen deflagration and detonation analyses. This bounding evaluation assumes that an amount of hydrogen equivalent to 100-percent active cladding oxidation burns all at once in the AP1000 containment, with no credit taken for the hydrogen igniters. The evaluation concludes that a hydrogen deflagration is unlikely to cause containment failure. Other analyses show that a deflagration to detonation transition in any part of the AP1000 containment is unlikely. Containment failure from a detonation is not considered a credible event for the AP1000 because of the lack of conditions supporting a deflagration to detonation transition, the provision and placement of hydrogen igniters, and the containment

design features resulting in a well-mixed atmosphere. Details are provided in subsection 10.2.5 of the PRA evaluation report.

The hydrogen igniters and the containment electrical and mechanical penetrations are designed to operate in the most limiting severe accident environment, including a hydrogen burn. (See subsection 10.2.5 of the PRA evaluation report.) The approach of using controlled burning to prevent accidental hydrogen burn initiation provides confidence that safety-related equipment will continue to operate during and after hydrogen burns. (See subsection 6.2.4.)

Issue 124 Auxiliary Feedwater System Reliability

Discussion:

Generic Safety Issue 124 addresses the use of probabilistic risk assessment to evaluate the reliability of the auxiliary feedwater system. The issue was resolved by the NRC's issuing plant-specific requirements for a few plants that did not initially have a reliability higher than a minimum criteria.

AP1000 Response:

This issue is not applicable to the AP1000. The AP1000 does not have a safety-related auxiliary feedwater system. The passive core cooling system provides the safety-related function of cooling of the reactor coolant system in the event of loss of feedwater. The startup feedwater system provides the steam generators with feedwater during plant conditions of startup, hot standby, and cooldown and when the main feedwater pumps are unavailable. The startup feedwater system has no safety-related function beyond containment isolation.

Issue 128 Electrical Power Reliability

Discussion:

Generic Safety Issue 128 addresses the reliability of onsite electrical systems and encompasses GSI 48, GSI 49, and GSI A-30.

AP1000 Response:

The design basis and design criteria for the Class 1E dc and UPS system is provided in subsections 8.1.4.2.1 and 8.1.4.3. The class 1E dc and UPS system design is described in subsection 8.3.2.1.1. Specifically, this design addresses IEEE Standards 603 and 308. This includes the following generic issues:

- Generic Safety Issue 48, LCO for Class 1E vital instrument buses in operating reactors. Chapter 16 provides the AP1000 technical specifications. Subsections 16.1.3.8.3 and 16.1.3.8.4 provide the limiting conditions for operation in the event of a loss of one or more Class 1E 120-vac vital instrument buses and the associated inverters. The AP1000 Class 1E buses have no tie breakers

- Generic Safety Issue 49, interlocks and LCOs for Class 1E tie breakers. Based on the historical background, this issue is not applicable to the AP1000 design. There are no tie breakers between the four class 1E divisions.

- Generic Safety Issue A-30, adequacy of safety-related dc power supplies. The AP1000 incorporates the following recommended enhancements:

  – The Class 1E dc distribution system design is in accordance with the guidelines of IEEE Standard 384 and Regulatory Guide 1.75.

  – Four separate divisions of Class 1E dc power are provided.

The AP1000 design provides additional testing capability through the installed spare battery bank with one installed battery charger. The spare battery bank permits frequent full-component testing without compromising plant availability. Battery equalization can be performed off-line. The battery and battery charger can be tested and maintained separately.

Issue 130 Essential Service Water Pump Failure at Multiple Plant Sites

Discussion:

Generic Safety Issue 130 addresses the use of shared or cross-connected essential service water systems at sites with two or more reactor plants. During some situations the crosstied pumps may not be available for accident mitigation operations.

AP1000 Response:

The AP1000 is a single, independent plant that does not share or cross-tie systems or components with another plant. See Section 1.2 for a general description of the plant. This issue is not applicable to the AP1000.

Issue 135 Integrated Steam Generator Issues

Discussion:

Generic Safety Issue 135 was initiated to provide an integrated work plan for the resolution of steam generator issues including steam generator overfill consequences, water hammer, and eddy current testing. The issue was divided into the following four tasks:

1. Assessing current capabilities of eddy current testing and developing recommendations.

2. Reviewing SGTR results and conclusions to develop regulatory analysis supporting Standard Review Plan changes.

3. Reassessing SGTR associated issues including radiological, design basis, tube integrity, procedures, and RCS pressure control.

4. Reviewing the effects of water hammer, overfill and water carryover.

The results of the tasks will provide the staff with a basis to develop a position on offsite dose, operator action, tube integrity, water hammer, and valve operability.

AP1000 Response:

The AP1000 design features are discussed below.

TASK 1: Appendix 1A identifies the level of conformance with Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes." As detailed in Appendix 1A, the AP1000 conforms with the regulatory guidance except where state-of-the-art advances have enhanced inservice inspection techniques. Further, as specified in subsection 5.4.2.5, the steam generators permit access to tubes for inspection and/or repair or plugging, if necessary, per the guidelines described in Regulatory Guide 1.83. The AP1000 steam generator includes features to enhance robotics inspection of steam generator tubes without manned entry of the channel head.

TASK 2: Subsection 15.6.3.1.4 discusses anticipated operator recovery actions and the effects of those actions in the mitigation of a steam generator tube rupture (SGTR). As discussed in subsection 15.6.3.2, the AP1000 incorporates automatic steam generator overfill protection. The details of the design are provided in subsection 15.6.3.2, with the control logic provided in Section 7.2.

TASK 3: The following sections of the DCD provide pertinent details on SGTR issues.

- Reassessment of radiological consequences: Subsection 15.6.3 provides details of the scenario, analysis assumptions, and results.

- Re-evaluation of design basis SGTR: The design basis SGTR evaluated on the AP1000 is discussed in subsection 15.6.3, providing details of the scenario, analysis assumptions and results.

- Supplemental Tube Inspections: See subsection 5.4.2.5, Appendix 1A, Regulatory Guide 1.83.

- Denting criteria: Subsection 5.4.2.4.3 provides a discussion of steam generator design and tubing compatibility with secondary coolants.

- Improved accident monitoring and reactor vessel inventory measurement: Section 7.5 discusses the safety related display information.

- Reactor coolant pump trip: Subsection 7.3.1.2.5 discusses reactor coolant pump trip.

- Control room design: Sections 7.5 and 18.8 discuss the control room design and design process.

- Emergency operating procedures: Subsection 18.9 addresses the development of emergency operating procedures.

- Organizational responses: Chapter 13 identifies that the organizational responses are a part of the combined license application.

- Reactor coolant pressure control: Subsection 7.7.1.6 addresses primary system pressure control.

TASK 4: Steam generator overfill, water carryover and water hammer are addressed as discussed in subsection 15.6.3.2, with the control logic provided in Section 7.2.

Issue 142 Leakage Through Electrical Isolators in Instrumentation Circuits

Discussion:

Generic Issue 142 addresses the susceptibility to leakage of isolation devices between safety- and nonsafety-related electrical systems. The NRC requires that licensees identify isolation devices in instrumentation circuits that are potentially susceptible to electrical leakage, define and perform an inspection and test program, replace failed or unacceptable isolators, and implement an annual program to inspect and test all electronic isolators between Class 1E and non-Class 1E systems.

AP1000 Response:

The use of isolation devices in the AP1000 Instrumentation and Control Architecture is described in subsections 7.1.2.10, "Isolation Devices," 7.7.1.11, "Diverse Actuation System," and WCAP-15776 (Reference 70), Section 3.9, "Conformance to the Requirements to Maintain Independence Between Safety Systems and Other Interconnected Equipment (Paragraph 5.6.3.1 of IEEE 603-1991)." As stated in WCAP-15776, Section 3.9, the isolation devices are tested to conform to requirements. This testing meets the requirement for an inspection and test program and identifies those devices that are potentially susceptible to electrical leakage. Implementation of an annual program to inspect and test all electronic isolators between Class 1E and non-Class 1E systems is the responsibility of the Combined License holder. The use of fiber-optic data links eliminates electrically conductive paths between receiving and transmitting terminals, and eliminates the potential for electrically generated noise caused by leakage through an isolator. These communication links also use extensive testing and error checking to minimize erroneous transmissions. These data links are described in subsection 7.1.2.8, "Communication Functions." In addition, electromagnetic design, testing, and qualification is performed as described in WCAP-15776, Section 2.6, "Design Basis: Range of Conditions for Safety System Performance (Paragraph 4.7 of IEEE 603-1991.)"

Issue 143 Availability of Chilled Water System and Room Cooling

Discussion:

This issue relates to the need to maintain air cooling systems in some rooms containing safety-related system components.

AP1000 Response:

This issue does not apply to the AP1000. The AP1000 does not rely on active safety systems to provide safe shutdown of the plant. A total loss of HVAC systems will not prevent a safe shutdown.

Issue 153 Loss of Essential Service Water in LWRs

Discussion:

This issue is related to the reliability of essential service water and the failure of such systems due to fouling mechanisms, ice effects, design deficiencies, flooding, multiple equipment failures, and personnel errors. This issue has been the subject of a number of generic communications from the NRC staff.

AP1000 Response:

This issue is not applicable to the AP1000. The AP1000 does not rely on the service water and component cooling water systems to provide safety-related safe shutdown.

Issue 163 Multiple Steam Generator Tube Leakage

Discussion:

This issue identifies a safety concern associated with potential multiple steam generator tube leaks triggered by a main steam line break outside containment that cannot be isolated. This sequence of events could lead to core damage due to the loss of all primary system coolant and safety injection fluid in the refueling water storage tank.

AP1000 Response:

The AP1000 plant response to a main steam line break (MSLB) scrams the reactor automatically and removes decay heat via the intact generator or the PRHR heat exchanger. If the MSLB is not isolated, the RCS will continue to lose coolant after shutdown through leaking steam generator tubes; the plant responds to the scenario as a small LOCA. The core makeup tanks drain and produce a low level signal. The plant protection and monitoring system depressurizes the RCS via the automatic depressurization system (ADS). The core remains covered throughout the scenario. Once the RCS is depressurized, the much lower containment pressure stops the containment water loss through the leaking steam generator tubes. Therefore, no long-term core uncovery is expected.

Issue 168 Environmental Qualification of Electrical Equipment

Discussion:

This issue is related to the effects of cable aging and whether the licensing basis for older plants should be reassessed or enhanced in connection with license renewal, or whether they should be reassessed for the current license term.

AP1000 Position:

This issue does not apply to the AP1000. Design Certification and Combined License actions on the AP1000 will be based upon current cable requirements. Reassessments are not required.

Issue 185 Control of Recriticality Following Small-Break LOCAs in PWRs

Discussion:

This issue is related to the potential for large reactivity transients, including prompt criticality, and significant heat generation resulting from natural circulation flow of unborated water formed in steam generators following small-break LOCAs.

AP1000 Position:

This scenario is not a safety concern for the AP1000 because of the passive safety systems designed to mitigate the consequences of a LOCA. Specifically, the automatic depressurization system operates to reduce primary system pressure and, thus, prevents significant heat transfer in the steam generators. Consequently, the steam generators should not generate any significant amount of boron-free condensate via reflux condensation over an extended period during a LOCA event. In the AP1000 design, the steam generator functions as a "heat source" as the RCS depressurizes, rather than a "heat sink" as it does in conventional PWR designs. Therefore, the differential temperature across the primary and secondary side of the generators is such that steam from the reactor will not condense on the tubes.

Another important design feature of the AP1000 that reduces the significance of this event is the elimination of the loop seal in the inlet to the reactor coolant pump. By elimination of the crossover leg piping, a large volume of boron-free condensate cannot collect in the loop piping. Thus, restart of the reactor coolant pumps following a LOCA will not result in a large slug of unborated water entering the core.

Post-LOCA, the PRHR heat exchanger can act as a heat sink and potentially could be a source of unborated water post-LOCA. However, condensate from the PRHR heat exchanger outlet mixes with the borated injection from the core makeup tanks and accumulators, and adequately mixes in the reactor vessel downcomer to prevent post-LOCA boron dilution. Long-term boration of the core is provided by the injection from the borated IRWST.

Issue 191 Assessment of Debris Accumulation on PWR Sump Performance

Discussion:

This issue addresses new contributors to debris and possible blockage of PWR sumps.

AP1000 Position:

The AP1000 has two sets of screens to which this issue may apply: the sump recirculation screens and the IRWST recirculation screens.

For the sump recirculation screens, an increase in pressure drop due to a mixed fiber-particulate was calculated and is considered conservative for the following reasons:

- The limiting flow case was assumed. That is, only one of the two recirculation screens was taken to be operable due to the assumed break location. This provided for a maximum velocity to and across the operating recirculation screen, and also maximized the potential for debris transport to the operating recirculation screen.

- The total amount of latent containment debris used in the evaluation is considered large. An aggressive foreign materials exclusion program and good housekeeping practices are expected to maintain latent containment debris sources well below the 500-pound level.

- The maximum debris loading on the containment recirculation screen is assumed. No credit is taken for the holdup of latent containment debris elsewhere in the containment (in dead-ended cubicles and rooms, on IRWST screens, and the like.)

- A conservatively low density for the latent fibrous debris was assumed. Assuming the latent fibrous debris had a density equal to that of water provided for a maximum volume of fibrous debris, and hence a maximum thickness of the resulting debris bed, on the recirculation screen.

Therefore, it was concluded that the current AP1000 design is not susceptible to loss of natural circulation of coolant from the containment due to sump recirculation screen blockage resulting from deposition of latent containment debris on the recirculation screen.

A study was also performed for the IRWST recirculation screens. Even though there is a low probability of having debris in the IRWST and having that debris transported to the screens, the IRWST screens and the PXS have significant capability to tolerate debris. A bounding analysis of the pressure drop that could be caused by debris (fiber and particle) on the IRWST screens has been performed for the AP1000.

It was concluded that the current AP1000 design is not susceptible to degradation of IRWST gravity injection flow due to IRWST recirculation screen blockage resulting from deposition of latent containment debris on the screens.

1.9.4.2.4 Human Factors Issues

These issues were outlined in the Human Factors Program Plan and are documented in NUREG-0985, Revision 1. The Human Factors Program Plan includes the human factors tasks required to address NUREG-0660.

HF4.4 Guidelines for Upgrading Other Procedures

Discussion:

The need was evaluated to develop technical guidance for use in upgrading normal operating procedures and abnormal operating procedures, similar to what the NRC staff completed for

emergency operating procedures. NUREG-0933 classified this item as resolved with no new requirements.

AP1000 Response:

Procedure development is the responsibility of the Combined License applicant as stated in DCD Section 13.5

HF5.1 Local Control Stations

Discussion:

Human Factors Issue 5.1 addresses the need to develop additional guidance for the design of local control stations.

AP1000 Response:

The AP1000 local control stations are designed using the same human factors engineering (HFE) design process as is used for the main control room (MCR). The human factors engineering design process is described in Chapter 18 of the DCD. Subsection 18.8 provides a description of the human system interface (HSI) design element of the overall design process. As part of the human system interface design process, design guidelines for each interface, such as workstation displays, are generated. These guidelines are used when designing the respective interface and control stations. This provides consistency of human system interface design, including local control stations, with the main control room.

HF5.2 Review Criteria for Human Factors Aspects of Advanced Controls and Instrumentation

Discussion:

Human Factors Issue 5.2 addresses review criteria for human factors aspects of advanced controls and instrumentation.

AP1000 Response:

Chapter 18 of the DCD describes the human factors engineering (HFE) program for the AP1000. Section 18.4 includes a description of the Functional Requirements Analysis and Allocation (element 3) for the AP1000. The objective of this allocation process is to define the AP1000 safety function requirements and allocate functions between the human and the machine appropriately. Section 18.8 also presents the implementation plan for the human system interface (HSI) design. This description of the human system interface design process includes the development of design guidelines, the execution of man-in-the-loop concept testing, review of human system interface design, and the use of a full-scale mockup.

The AP1000 human system interface (HSI)/man-machine interface (MMI) includes the following resources:

- Alarm system
- Computerized Procedure System
- Plant Information System
- Qualified Data Process System (QDPS)
- Controls (dedicated and soft)
- Wall Panel Information System (WPIS)

The implementation plan for the design of each of these human system interfaces (HSI design) is described in section 18.8. The mission statements and high-level information for each of these resources is also provided in Section 18.8. The plant information system provides display at the operators workstation. The qualified data process system provides qualified (Class 1E) displays to operator, located at the dedicated safety panel. The alarm system provides alarm overviews which are integrated into the wall panel information system and it provides alarm support displays at the operator's work station. Alarms are integrated into the workstation displays. There will be a navigational link from an alarm support display for a specific alarm to its associated alarm response procedure as presented to the operator by the computerized procedure system. Design guidelines for each human system interface is developed as part of the human system interface design (as described in subsection 18.8). These design guidelines are developed from existing industry guidelines and considerations specific to the technology planned for the human system interface. Human factors engineering specialists are part of the human factors engineering/man-machine interphase design team (DCD Section 18.2) and will be involved in the development of the design guidelines.

1.9.5 Advanced Light Water Reactor Certification Issues

This subsection addresses the advanced light water reactor issues identified by the NRC in SECY-90-016 (Reference 29), in the February 27, 1992 NRC letter from D. M. Crutchfield to E. E. Kintner (Reference 30).

1.9.5.1 SECY-90-016 Issues

The following issues were outlined in SECY-90-016 (Reference 29).

1.9.5.1.1 Advanced Light Water Reactor Public Safety Goal

NRC Position:

Based on current regulatory guidance, including the NRC Severe Accident Policy Statement, Standardization Policy Statement, and Safety Goal Policy Statement, it is expected that any new standard plant design will result in a higher level of severe accident safety than current plant designs. This is achieved by improving safety and by striking a balance between accident prevention and mitigation.

The overall objective of the public safety goal is to significantly reduce or eliminate the likelihood of known major safety issues.

The safety goals approved by the NRC in the Staff Requirements Memorandum to SECY-90-016 (Reference 31) are as follows:

- The mean core damage frequency target for each design should be less than $1.0x10^{-4}$ per reactor year.
- The overall mean frequency of a large release of radioactive materials to the environment from a reactor accident should be less than 1 in 1,000,000 per year of reactor operation, where a large release is defined as one that has a potential for causing an early offsite fatality.

AP1000 Response:

The AP1000 level 1, 2, and 3 PRA evaluations for both internal and external events (excluding seismic events) demonstrate conformance with the NRC safety goals. The AP1000 PRA evaluates shutdown events and provides additional information and specific results.

1.9.5.1.2 Use of Physically-Based Source Term

NRC Position:

As noted in SECY-95-172 (Reference 57), the NRC plans to use the accident source term model from NUREG-1465 (Reference 58). This source term model provides a physically based approach to modelling of activity releases from the reactor core to the containment in the event of a core degradation accident. As discussed in SECY-94-302 (Reference 59), for the design basis accident, release of activity from the core will not be assumed to extend beyond the in-vessel release phase.

In calculating the radiological consequences of accidents, as stated in Reference 57, the NRC intends to use the model presented in SECY-94-194 (Reference 60) which identifies the proposed changes to 10 CFR Parts 50 and 100. The pertinent features that will be applied to the determination of accident radiological consequences are:

- In place of thyroid and whole body dose limits, dose limits are specified as total effective dose equivalent (TEDE). The offsite dose limits of 25 rem whole body and 300 rem thyroid are replaced by a limit of 25 rem TEDE. The dose limit for the control room operators (currently identified in SRP Section 6.4 as 5 rem whole body, 30 rem thyroid, and 30 rem beta skin) is replaced by 5 rem TEDE which is consistent with GDC 19.
- Instead of calculating the site boundary dose over the first two hours of the accident, the dose is to be calculated for the two hour interval over which the highest dose would be calculated.

AP1000 Response:

The AP1000 radiological consequence analysis utilizes the accident source term provided in Regulatory Guide 1.183.

1.9.5.1.3 Anticipated Transients Without Scram (ATWS)

NRC Position:

This former unresolved safety issue was resolved with the issuance of Rule 10 CFR 50.62. Requirements for currently operating pressurized water reactors include diverse reactor trip (except for Westinghouse plants) and diverse actuation of auxiliary feedwater and turbine trips.

The Staff Requirements Memorandum to SECY-90-016 (Reference 31) approved the requirement for diverse reactor trip systems for evolutionary advanced light water reactors. However, it added that if the applicant can demonstrate that the consequences of an anticipated transient without reactor trip are acceptable, the NRC should accept the demonstration as an alternative to the diverse reactor trip system.

AP1000 Response:

The AP1000 complies with the current rules on an anticipated transient without reactor trip as specified in 10 CFR 50.62.

The AP1000 design includes the following design features aimed at minimizing the probability of occurrence of an anticipated transient without reactor trip and at mitigating the consequences if it occurs.

- The design of the protection and safety monitoring system is highly reliable, using a two out of four coincidence logic and featuring continuous diagnostic testing. The system incorporates fail-safe features to the extent practical. It is designed to generate a reactor trip signal and to generate an actuation signal for most engineered safety features components when protection system failures occur.

- For a reactor trip, the switchgear consists of eight circuit breakers arranged in a two out of four matrix located in two separate cabinets. The trip is implemented by undervoltage trip attachments and diverse shunt trip devices on the circuit breakers. To initiate a reactor trip, power is interrupted to the undervoltage trip attachment, while the shunt trip attachment is energized. Either device trips the breaker. The eight-breaker configuration permits testing of the reactor trip breakers without the use of auxiliary bypass breakers.

- The reactor trip switchgear can be actuated manually from the main control room by reactor trip switches hard-wired to the shunt trip attachment and undervoltage coils for each reactor trip breaker. In addition, it is possible to manually initiate a reactor trip from the main control room by turning off the motor-generators that provide power for control rod operation.

- A nonsafety-related diverse actuation system is included in the AP1000 design. The diverse actuation system inserts control rods by de-energizing the field windings of the control rod motor-generators.

- The diverse actuation system trips the turbine and diversely actuates selected other engineered safeguards functions. Additional details of the diverse actuation system are included in Section 7.7.

Section 15.8 describes the evaluation of an anticipated transient without reactor trip.

1.9.5.1.4 Midloop Operation

NRC Position:

Loss of decay heat removal function has occurred on a number of occasions in operating plants. In response to these events, the NRC issued Generic Letter 87-12 requesting that operating plants provide information regarding mid-loop operation. Generic Letter 88-17 requested additional information and provided guidance to operating utilities. Subsequent NRC evaluations have indicated that loss of decay heat removal during midloop operation may contribute significantly to public risk.

It is the NRC position that for future plants, conformance with Generic Letter 88-17 is insufficient, and additional hardware features should be incorporated into the design.

The Staff Requirements Memorandum to SECY-90-016 (Reference 31) approved the proposed NRC position, with the following four additional recommendations made by the ACRS:

- Design provisions to help ensure continuity of flow through the core and residual heat removal system with low liquid levels at the junction of the decay heat removal system suction lines and the reactor coolant system

- Provisions to ensure availability of reliable systems for decay heat removal

- Instrumentation for reliable measurements of liquid levels in the reactor vessel and at the junction of the decay heat removal system suction lines and the reactor coolant system

- Provisions for maintaining containment closure or for rapid closure of containment openings.

AP1000 Response:

The following features are incorporated into the design of the reactor coolant system and the normal residual heat removal system for continued performance of the residual heat removal function during midloop operation:

- The layout of the reactor coolant system hot leg piping and the steam generator channel head is such that installation of the nozzle dams can be performed with an 80 percent level in the hot leg piping. This is about 9 inches above the actual hot leg piping midplane elevation. (The hot leg piping has a 31-inch inside diameter.)

- A specially designed vortex breaker is used for the normal residual heat removal system suction nozzle. This vortex breaker connects vertically to the bottom of the hot leg piping. The normal residual heat removal system suction piping is connected to the bottom of this vortex

breaker. With the vortex breaker, the amount of air entrainment remains below 10 percent unless the hot leg is essentially drained. Therefore, the potential for a loss of normal residual heat removal system flow and damage to the normal residual heat removal pump is substantially reduced.

- The normal residual heat removal pump suction piping is designed to be self-venting by sloping the lines continuously upward from the pump to the hot leg connection at the vortex breaker. If the pump should stop during midloop operation, any air bubbles present in the pump or suction piping are vented back up through the suction line to the water surface in the hot leg. This feature allows the operator to rapidly restart the pump with an air-free suction line.

- The normal residual heat removal pumps are designed to minimize cavitation and other adverse conditions when operating with minimal subcooling of the reactor coolant. Specifically, the plant piping layout configuration (such as piping elevations and routing) and the available and required pump net positive suction head characteristics allow the normal residual heat removal pumps to be started and operated at their full design flow rates, with saturation conditions in the reactor coolant system (associated with boiling in the reactor vessel). Therefore, the normal residual heat removal system is readily restored after a temporary loss of decay heat removal.

- The core makeup tanks, accumulators, and the in-containment refueling water storage tank are isolated, but can be manually actuated during midloop operations. In addition, the in-containment refueling water storage tank is automatically actuated on a sustained loss of shutdown decay heat removal. This arrangement provides a reliable water source for maintaining the reactor coolant system inventory that is either automatically or manually actuated.

- Redundant narrow-range level instrumentation indicates the reactor coolant system water level between the bottom of the hot leg and the top of the steam generator inlet elbow. Indication and low level alarms are provided in the main control room. In addition, this instrumentation actuates the in-containment refueling water storage tank makeup.

- Wide-range pressurizer level instrumentation used during cold plant operations is expanded to the bottom of the hot legs. This provides a continuous level indication in the main control room, from the normal level in the pressurizer to the range of the two narrow-range hot leg level instrumentation.

- Normal residual heat removal system heat exchanger discharge flow instrumentation provides main control room indication of return flow to the reactor vessel. A low-flow alarm alerts the operator to a decrease in normal residual heat removal system return flow from either heat exchanger.

- The drain-down of the reactor coolant system to the midloop operating level and the subsequent reactor coolant system inventory control during midloop operation are performed by the operator from the main control room.

The plant design precludes the need to locally coordinate actions in the containment with the main control room operators to control the reactor coolant system drain-down rate and level.

- Reactor coolant system hot leg wide range temperature instruments are provided in each hot leg. The orientation of the wide range thermowell-mounted resistance temperature detectors enable measurement of the reactor coolant fluid in the hot leg when in reduced inventory conditions. In addition, at least two incore thermocouple channels are available to directly measure the core exit temperature during midloop residual heat removal operation. These two thermocouple channels are associated with separate electrical divisions.

- The automatic depressurization system first-, second-, and third-stage valves, connected to the top of the pressurizer, are open whenever the core makeup tanks are blocked during shutdown conditions while the reactor vessel upper internals are in place. This provides a vent flow path to preclude pressurization of the reactor coolant system during shutdown conditions when decay heat removal is lost. This also allows the in-containment refueling water storage tank to automatically provide injection flow if it is actuated on a sustained loss of decay heat removal.

Administrative controls require containment closure capability in modes 5 and 6, during reduced inventory operations, and when the upper internals are in place. Containment closure capability is defined as the capability to close the containment prior to core uncovery following a loss of the normal decay heat removal system (that is, normal residual heat removal system). The containment design also includes penetrations for temporary cables and hoses needed for shutdown operations. These penetrations are isolated in an emergency.

In addition to these design features, appropriate procedures are defined to guide and direct the operator in the proper conduct of midloop operation and to aid in identifying and correcting abnormal conditions that might occur during shutdown operations.

1.9.5.1.5 Station Blackout

NRC Position:

The NRC has issued NUREG-0649 (Reference 34), NUREG-1032 (Reference 35), and NUREG-1109 (Reference 36) to address the unresolved safety issue of station blackout (USI-44). See subsection 1.9.4 for a discussion of USI-44.

To resolve this issue, the NRC published 10 CFR 50.63 and Regulatory Guide 1.155, which establish new requirements so that an operating plant can safely shut down following a loss of all ac power. SECY-94-084 (Reference 67), discusses station blackout for passive plants.

AP1000 Response:

The AP1000 is in conformance with the NRC guidelines for station blackout.

The AP1000 design minimizes the potential risk contribution of station blackout by not requiring ac power sources for design basis events. Safety-related systems do not need nonsafety-related ac power sources to perform safety-related functions.

The AP1000 safety-related passive systems automatically establish and maintain safe shutdown conditions for the plant following design basis events, including an extended loss of ac power sources. The passive systems can maintain these safe shutdown conditions after design basis events, without operator action, following a loss of both onsite and offsite ac power sources. Subsection 1.9.5.4 provides additional information on long-term actions following an extended station blackout beyond 72 hours.

The AP1000 also includes redundant nonsafety-related onsite ac power sources (diesel-generators) to provide electrical power for the nonsafety-related active systems which provide defense in depth.

AP1000 design features that mitigate the consequences of a station blackout are as follows:

- A full-load rejection capability to reduce the probability of loss of onsite power
- Safety-related passive residual heat removal heat exchanger
- Safety-related passive containment cooling
- Bleed and feed capability, using the safety-related automatic depressurization system in conjunction with the water available from the core makeup tanks, the accumulators, and the in-containment refueling water storage tank
- Class 1E batteries sized for 72 hours of operation under station blackout conditions
- A nonsafety-related reserve auxiliary transformer to provide power to selected ac power systems
- A nonsafety-related ac power system that includes two diesel-generators that automatically start on loss of offsite power
- An automatic nonsafety-related load-sequencing circuit that starts the following redundant nonsafety-related equipment after a loss of offsite power, once the associated diesel-generator is started:
  - Startup feedwater pump
  - Component cooling water pump
  - Service water pump
  - Battery chargers
- Reactor coolant pumps without shaft seals
- Passive cooling for the rooms containing equipment assumed to operate during station blackout conditions (the protection and safety monitoring system cabinet rooms and the main control room) so that this equipment continues to operate. (Section 6.4 provides additional information.)

1.9.5.1.6 Fire Protection

NRC Position:

Current fire protection criteria are contained in GDC 3 and 10 CFR 50.48, guidelines for compliance with these criteria are provided in the Standard Review Plan, Section 9.5.1, including Branch Technical Position CMEB 9.5-1. Reference 9 identifies the following enhancements:

- Alternative, dedicated shutdown capability for main control room fires.
- Safe shutdown capability required for a fire in any other fire area, without reliance on any equipment in that area or re-entry into that area for repairs or for performance of operator actions.
- Fire protection for redundant shutdown systems in the reactor containment building must be provided to ensure, to the extent practicable, that on shutdown the division will be free of fire damage.
- Migration of smoke, hot gases, or fire-suppressant chemicals into other applicable fire areas must be minimized by design to prevent any adverse impact on safe shutdown capability, including operator actions.

SECY-98-161 (Reference 66) presents the results of the NRC review of the AP1000 Fire Protection System.

AP1000 Response:

Enhanced fire protection has been one of the goals of the AP1000 design. The following physical separation philosophy is used:

Outside Containment:

- Within the nuclear island, redundant divisions of safety-related equipment outside containment are located in safety-related areas separated from each other and from other areas in the plant by fire barriers with a minimum fire resistance rating of 3-hours to provide that safe shutdown can be achieved. Since most safety-related mechanical equipment is located inside containment, this applies primarily to the protection and safety monitoring system and the Class 1E dc and UPS system.
- Each safety-related area is provided with ventilation isolation provisions at the fire barrier boundaries to minimize the migration of smoke, hot gasses, or fire suppressant chemicals into other safety-related areas. Fiber-optic cables are used to provide communication between redundant protection and safety monitoring divisions.

- Exceptions to the use of three-hour fire barriers outside containment are made only in cases where physical separation conflicts with other requirements or where the equipment is not clearly division oriented, such as the main control room, the remote shutdown room, the main steam tunnel, and the passive containment cooling system valve room.

Inside Containment:

- The containment is a single fire area. Separation by three-hour fire barriers inside containment is not practical due to issues of hydrogen venting, compartment pressure equalization, and during high-energy line breaks and for system functionality. To the extent practical, separation is provided between redundant safety-related equipment.

- Separation between redundant safety-related equipment is accomplished by using existing structural walls. Where this is not possible, other methods are used, such as physical separation with no intervening combustibles.

- To the extent practical, the containment is split into two different fire zones for the purpose of routing of protection and safety monitoring system cabling and electrical power cabling. Divisions A and C cabling is routed below the operating deck, while Divisions B and D cabling is routed above the operating deck. Additional separation is provided by existing floors and walls and by the physical separation of cabling runs. Protection for the primary input sensors and the final actuation devices is accomplished by the physical separation of the various sensors and components using existing containment walls as barriers.

- The in-containment fire area contains reduced combustible material due to the use of canned reactor coolant pump motors that do not use oil lubrication and due to strict combustible material limitations.

Main Control Room:

- Functionality requirements dictate that the main control room be a single fire zone. Features are included in the main control room to:

  - Reduce the probability of fire initiation
  - Reduce the likelihood of fire spreading
  - Increase the probability of fire detection
  - Effectively mitigate the effects of a fire

- In the event of main control room evacuation, safe shutdown conditions are established and maintained using the remote shutdown workstation.

See Appendix 9A.3 for information on the main steam tunnel and the passive containment cooling system valve room. See subsection 9.5.1 and Appendix 9A for additional information.

1.9.5.1.7 Intersystem LOCA

NRC Position:

Overpressurization of low-pressure piping systems due to reactor coolant system boundary isolation failure could result in rupture of the low-pressure piping outside containment. This may result in a core melt accident with an energetic release outside the containment building that could cause a significant offsite radiation release.

It is the NRC position that designing interfacing systems to withstand full reactor pressure is an acceptable means of resolving this issue. The Staff Requirements Memorandum to SECY-90-016 (Reference 31) added that consideration should be given to all elements of the low-pressure system (such as instrument lines, pump seals, heat exchanger tubes, and valve bonnets). For interfacing systems not designed to withstand full reactor coolant system pressure, it is necessary to provide leak testing capability for the pressure isolation valves, main control room position indication for de-energized reactor coolant system isolation valves, and high pressure alarms to alert control room operators when increasing reactor coolant system pressure approaches the design pressure of attached low-pressure systems and both isolation valves are not closed.

AP1000 Response:

The AP1000 has incorporated various design features to address intersystem loss-of-coolant accident challenges. These design features result in very low AP1000 core damage frequency for intersystem loss-of-coolant accidents compared with operating nuclear power plants. The design features are primarily associated with the normal residual heat removal system and are discussed in Section 3 of WCAP-15993 (Reference 56) as well as DCD subsection 5.4.7. WCAP-15993 was prepared to document the evaluation of the AP1000 for conformance to the intersystem loss-of-coolant accident regulatory criteria identified in various NRC documents. See that document for additional information on conformance to intersystem loss-of-coolant accident regulatory criteria.

1.9.5.1.8 Hydrogen Generation and Control

NRC Position:

It is the NRC position that the likelihood of early containment failure from hydrogen combustion should be reduced. Because of the uncertainties in the phenomenological knowledge of hydrogen generation and combustion, advanced light water reactors should be designed to:

- Accommodate hydrogen equivalent to 100 percent metal-water reaction of the fuel cladding
- Limit containment hydrogen concentration to no greater than 10 percent

Further, because hydrogen control is necessary to preclude local concentrations of hydrogen below detonable limits, and given uncertainties in present analytical capabilities, advanced light water reactors should provide containment-wide hydrogen control (such as igniters or inerting) for severe accidents. Additional advantages of providing hydrogen control mitigation features (rather than reliance on random ignition of richer mixtures) includes the lessening of pressure and temperature loadings on the containment and essential equipment.

AP1000 Response:

The AP1000 design includes mechanisms for monitoring and controlling hydrogen inside the containment. The containment hydrogen control system maintains hydrogen concentrations below 10 percent following the reaction of 100 percent of the zircaloy cladding.

Passive autocatalytic hydrogen recombiners control hydrogen concentration following design basis events. Nonsafety-related hydrogen igniters control rapid releases of hydrogen during and after postulated events with degraded core conditions or with core melt.

Sufficient vent area is provided for each subcompartment in the containment to prevent high local concentrations of hydrogen.

The containment air filtration system provides a capability to purge the containment atmosphere.

See subsection 6.2.4 for additional information.

1.9.5.1.9 Core-Concrete Interaction - Ability To Cool Core Debris

NRC Position:

Containment integrity could be breached in the event of a severe accident in which the core melts through the reactor vessel, resulting in interaction between core debris and concrete, which can generate large quantities of hydrogen and other gases. It is the NRC position that sufficient reactor cavity floor space be provided to enhance debris spreading, and that a method for quenching debris in the reactor cavity be incorporated. The NRC staff has not formulated specific criteria for debris bed coolability and reviews each vendor's design to determine how they address the general criteria for debris spreading and quenching.

AP1000 Response:

The AP1000 design provides superior protection against core-concrete interaction by reliably depressurizing the reactor vessel and flooding the reactor cavity to cool the vessel and prevent debris from relocating from the vessel into the containment. Based on the DOE/ARSAP analysis of the thermal-hydraulics of in-vessel debris retention (see Section 19.39 and Appendix 19B as supported by Theofanous, T. G., et al., Reference 62) performed using the Risk Oriented Accident Analysis Methodology, the AP1000 has a large margin to reactor vessel failure in the depressurized, flooded cavity condition. This strategy eliminates the large uncertainties associated with ex-vessel debris relocation that could result in containment failure even while meeting the NRC criteria for debris coolability in the cavity.

In the event that cavity flooding fails, the floor area under the vessel provides debris spreading area to enhance the coolability of the debris. The AP1000 containment design drains the water from the reactor coolant system, core makeup tanks and accumulators to the reactor cavity to provide enough water to quench ex-vessel debris. The heat is ultimately removed from the containment via the passive containment cooling system, and the condensate is returned to the cavity to continue to provide cooling water to the debris bed.

1.9.5.1.10 High Pressure Core Melt Ejection

NRC Position:

Direct containment heating associated with the ejection of molten core debris, under high pressure, from the reactor vessel can result in a rapid addition of energy to the containment atmosphere. It is the NRC position that, pending completion of ongoing research, it is prudent to provide protection against this potential failure mode. This protection should include the following two aspects:

- Providing a rate of reactor coolant system depressurization to preclude molten core ejection and creep rupture of steam generator tubes

- Arranging the reactor cavity so that high-pressure core debris ejection resulting from reactor vessel failure does not impinge on the containment boundary

AP1000 Response:

The AP1000 design includes an automatic depressurization system that is redundant, diverse, independent of ac power sources, and automatically actuated. The automatic depressurization system can also be manually actuated. Any of the automatic depressurization system lines can sufficiently reduce the reactor coolant system pressure to help preclude direct containment heating. Subsection 5.4.6 and Section 6.3 provide additional information on the automatic depressurization system.

In addition, the reactor cavity region and lower containment of the AP1000 are designed to preclude transport of significant core debris to the upper containment in the unlikely event of a high pressure melt ejection scenario from the reactor vessel. This is a passive feature involving the geometric configuration of the reactor cavity lower containment. There is no direct pathway from the cavity to the upper compartment.

1.9.5.1.11 Containment Performance

NRC Position:

The NRC opinion is that because there are substantial uncertainties in core damage predictions, and because it is very important to maintain defense in depth, it is necessary that the containment boundary serve as a reliable barrier against fission product release for credible severe accident challenges. Hence, a containment performance criterion has been proposed by the NRC.

The objective of the containment performance criterion is to provide a leaktight barrier against radioactive releases for two distinct categories of severe accident challenges:

- Rapid energy release, hydrogen combustion, and initial release of stored reactor coolant system energy

- Slow energy release, including decay heat and noncondensible gas generation, due to core-concrete interaction

The NRC position is that the reactor containment boundary should serve as a reliable barrier against fission product release for credible severe accident challenges. A conditional containment failure probability of 0.1 should be used unless a deterministic containment performance goal can offer comparable protection.

An alternate deterministic criterion proposed in SECY-90-016 (Reference 29) states that "...The containment should maintain its role as a reliable leak tight barrier by ensuring that containment stresses do not exceed ASME service level C limits for a minimum period of 24 hours following the onset of core damage..."

This capability should, to the extent practical, be provided by the passive capability of the containment and any related passive design features. The NRC further believes that following this 24-hour period, the containment should continue to provide a barrier against the uncontrolled release of fission products.

AP1000 Response:

The AP1000 design includes several features to minimize the potential for large fission product releases in the event of a severe accident. These features are aimed at both the prevention and the mitigation of severe accident phenomena that can threaten containment integrity. An adequate margin to containment performance is maintained.

The AP1000 containment is continuously cooled by natural air circulation outside the steel shell. During accident conditions, water drains on the outside of the containment vessel to increase heat transfer. The containment design best-estimate performance analysis alone shows that the maximum containment pressure reached maintains the containment shell stresses below the ASME Code Service Level C stress intensity limits, using a factor of safety of 1.5 for buckling of the top head.

Additionally, the probability of containment bypass scenarios is reduced by improved containment isolation, by designing to protect against interfacing system LOCAs, thereby reducing the associated core melt frequency, and by reducing the steam generator tube rupture core melt frequency.

The interfacing system LOCA core melt frequency is reduced by the use of several features, including effective leak testing of the normal residual heat removal system motor-operated isolation valves. A third valve is provided to the normal residual heat removal system suction line. It is a motor-operated valve located outside containment. This prevents inadvertently aligning the reactor coolant system to the normal residual heat removal system. The normal residual heat removal system design pressure is 900 psig. Therefore the ultimate rupture strength of the system prevents it from failing when exposed to the normal reactor coolant system operating pressure (2250 psig). See the position on intersystem LOCA for additional information on the normal residual heat removal system design against overpressurization.

Steam generator tube rupture core melt frequency is reduced by incorporating multiple levels of defense that are both redundant and diverse. The first level of defense relies on the use of nonsafety-related active systems and operator action. The second level of defense uses safety-related passive systems and equipment, such as the core makeup tanks and passive residual heat

removal heat exchangers, without the safety-related automatic depressurization of the reactor coolant system. The third level of defense uses the redundant and diverse safety-related automatic depressurization system valves to depressurize the reactor coolant system and initiate low-pressure passive injection. Any of these levels of defense can prevent core damage during a steam generator tube rupture event.

Finally, containment isolation capabilities are substantially improved by reducing the number of penetrations and the number of open paths. Most of the open containment penetration lines use fail-closed valves for automatic isolation.

1.9.5.1.12 ABWR Containment Vent Design

This issue is specific to BWRs and PWRs with ice condenser containments. Therefore this issue does not apply to the AP1000 design.

1.9.5.1.13 Equipment Survivability

NRC Position:

Safety-related equipment used to mitigate design basis events is subject to a comprehensive set of criteria such as redundancy, diversity, environmental qualification, and quality assurance to provide reasonable assurance that they perform their intended functions, if needed. However, equipment used to mitigate the effects of severe accidents should not be treated in the same manner because of large differences in the likelihood of occurrence. There should be reasonable assurance that the equipment will operate in the severe accident environment for which they are intended and over the time span for which they are needed. However, equipment provided only for severe accident protection need not be subject to the 10 CFR 50.49, environmental qualification requirements, 10 CFR 50, Appendix B quality assurance requirements, and 10 CFR 50 Appendix A, redundancy and diversity requirements.

AP1000 Response:

The equipment used to mitigate severe accidents is identified in the AP1000 PRA evaluation report. Because of the nature of the passive safety features of the AP1000, there is very little equipment in this category. Equipment used to mitigate severe accidents is designed to survive the environmental conditions identified in the AP1000 PRA evaluation.

1.9.5.1.14 Operating Basis Earthquake (OBE)/Safe Shutdown Earthquake (SSE)

NRC Position:

Currently, 10 CFR 100 requires that the magnitude of the operating basis earthquake be at least one-half that of the safe shutdown earthquake. This forces the safety-related system design at some plants to be controlled by the operating basis earthquake, but the NRC agrees that the operating basis earthquake should not control the safety-related system design. Therefore, the NRC recommends eliminating the operating basis earthquake from the design of systems, structures, and components. Until final rulemaking is approved for 10 CFR 100, Appendix A, the elimination of the operating basis earthquake from the design of passive plants will require an

exemption from current regulations, with acceptable supporting justification from the designer. The details of this process will be resolved with the NRC through the appropriate code-related activities or supplemental regulatory guidance.

AP1000 Response:

The operating basis earthquake is not used as a design basis for AP1000 safety-related structures, systems, and components. For safety-related equipment, the safe shutdown earthquake is used as the design basis. In specifying design criteria for this earthquake, consideration is given to lower magnitude earthquakes having a greater probability of occurrence, as well as to larger magnitude earthquakes having a lower probability.

Cyclic stresses due to earthquakes are included in the design of those components sensitive to fatigue. Analysis methods and allowable stresses provide margin for the design requirements for the safe shutdown earthquake. Sections 3.7 and 3.10 provide additional information.

1.9.5.1.15 In-Service Testing of Pumps and Valves

NRC Position:

Periodic testing according to ASME Code, Section XI is required to confirm operability of safety-related pumps and valves. The NRC believes that these testing requirements do not necessarily verify the capability of the components to perform their intended safety function. To address this concern, the NRC has issued Generic Letters 89-04 (Reference 38) and 89-10 (Reference 39), and has proposed rulemaking to extend in-service testing beyond code components and to demonstrate capability to perform safety functions. Reference 29 includes the following provisions to be applied to safety-related pumps and valves (not limited to only ASME Code Class 1, 2, or 3):

- Piping design should incorporate provisions for full-flow testing (maximum design flow) of pumps and check valves.

- Designs should incorporate provisions to test motor-operated valves under design basis differential pressure.

- Check valve testing should incorporate the use of advanced, nonintrusive techniques to address degradation and performance characteristics.

- A program should be established to determine the frequency necessary for disassembly and inspection of pumps and valves to detect unacceptable degradation that cannot be detected through the use of advanced, nonintrusive techniques.

In June 1990, the NRC position was approved, additionally noting that due consideration should be given to the practicality of designing testing capability, particularly for large pumps and valves.

The NRC concluded that this was an issue for passive plant designs in SECY-94-084 (Reference 67), because the safety-related passive systems rely on the proper operation of equipment such as check valves and depressurization valves to mitigate the effects of transients.

AP1000 Response:

The AP1000 safety-related passive systems include the following design features:

- The AP1000 does not include any safety-related pumps.
- The motor-operated valve design is simplified by extending opening and closing times and by using simplified, conservative valve designs.
- Safety-related motor-operated valves are designed to be cycled with the plant at power.
- Features are included in the design to provide proper operational testing of the appropriate check valves, motor-operated valves, and air-operated valves, including flow and differential pressure testing during shutdown conditions.

The in-service testing program for ASME Code Class 1, 2, and 3 valves is the responsibility of the Combined License applicant. See subsection 3.9.6 for additional information.

Subsection 3.9.6 summarizes the requirements for the in-service testing program, including industry standards and NRC recommendations. A description of the in-service inspection program is included in the technical specifications provided in Chapter 16. The AP1000 system and valve designs generally allow implementation of the NRC recommendations in Generic Letters 89-04 and 89-10. Requirements for nonsafety-related pumps and valves that support the operation of systems that preclude unnecessary operation of the safety-related passive systems are outlined in subsection 3.9.6.

The AP1000 in-service testing program provides for periodic testing of the safety-related passive system components. The safety-related passive system components and systems are designed to meet the intent of the ASME Code, Section XI, for in-service inspection.

The AP1000 is designed for the following basic types of in-service testing of safety-related components:

- Periodic functional testing of active components during power operation (such as cycling of specific valves)
- Periodic flow/differential pressure operability testing of active components
- Periodic leak testing of the containment isolation valves.
- Periodic system flow or heat transfer rate testing of passive safety-related injection or cooling features during plant shutdown

The passive system design includes specific features to support in-service test performance:

- Remotely operated valves can be exercised during plant operation.

- Level, pressure, flow, and valve position instrumentation is provided for monitoring passive system equipment during plant operation and testing.

- Permanently installed test lines and connections are provided for performance of the containment isolation valve leakage testing.

1.9.5.2 Other Evolutionary and Passive Design Issues

Other evolutionary and passive design issues were identified in Reference 30.

1.9.5.2.1 Industry Codes and Standards

NRC Position:

SECY-91-273 (Reference 40) discusses NRC concerns with the use of recently developed or modified design codes and industry standards that the ALWR vendors are using in applications, but that have not yet been reviewed by the NRC for acceptability. The NRC recommends using the newest codes and standards endorsed by the NRC in the review of passive design applications. Unapproved revisions to codes and standards will be reviewed on a case-by-case basis.

AP1000 Response:

When the AP1000 design is based on revisions of industry codes and standards later than those required by NRC regulation, such use is explicitly discussed in the appropriate DCD section. Use of codes and standards later than those recommended in NRC guidance documents is also discussed in the appropriate DCD section.

Appendix 1A discusses regulatory guide conformance. For those standards endorsed by regulatory guides and subsequently superseded by a more recent revision, when the later revision is used its use is discussed or indicated in Appendix 1A.

1.9.5.2.2 Electrical Distribution

NRC Position:

The Commission approved the recommendations in SECY-91-078 (Reference 41) for evolutionary plant designs to include the following:

1. An alternate power source for nonsafety-related loads unless design margins for loss of nonsafety-related loads are no more severe than turbine-trip-only events in current plants

2. At least one offsite circuit to each redundant safety division supplied directly from offsite power sources with no intervening nonsafety-related buses

The applicability of this issue to passive designs is discussed in SECY-94-084 (Reference 67).

AP1000 Response:

See the response to station blackout in subsection 1.9.5.1.

1.9.5.2.3 Seismic Hazard Curves and Design Parameters

NRC Position:

To assess the seismic risk associated with an ALWR design, EPRI proposed the use of generic bounding seismic hazard curves for sites in the central and eastern United States. EPRI proposes that these curves be used in the seismic PRA. NRC regulations do not require performance of a seismic PRA to determine site acceptability.

The NRC has compared the proposed EPRI ALWR seismic hazard bounding curve for rock sites to hazard curves derived by Lawrence Livermore National Laboratories (LLNL) using historical earthquake methodology in NUREG/CR-4885 and to hazard curves generated by EPRI for the Seabrook site. The LLNL hazard curves are generally higher than the EPRI results for the same sites.

The proposed EPRI bounding curve is exceeded for accelerations below 0.1g and the NRC questions the adequacy of the proposed EPRI bounding curve at higher peak accelerations. The NRC concludes that the EPRI bounding hazards curve is nonconservative and also that its use in a seismic PRA assessment would underpredict the core damage frequency. Therefore, the EPRI curves are not sufficiently conservative for ALWR designer use.

The Combined License applicant must demonstrate that site-specific seismic parameters meet the certified design parameters, or a site-specific analysis will be required to confirm site acceptability.

AP1000 Response:

The AP1000 includes a seismic margin assessment performed in lieu of a seismic PRA. The seismic margin assessment follows the guidelines established in NUREG-1407 (Reference 42). This assessment demonstrates that the AP1000, located at a site having the most severe seismic inputs meeting the AP1000 site interface requirements, has a seismic risk comparable to that at existing nuclear power plants.

1.9.5.2.4 Leak-Before-Break

NRC Position:

GDC 4 provides the basis for the leak-before-break (LBB) analysis that has been approved for PWR primary piping, and the pressurizer surge, accumulator, and residual heat removal piping. In addition, it has been used for primary piping inside containment and for piping at least 6 inches nominal diameter and for both austenitic and carbon steel (clad with stainless) materials.

The NRC will evaluate the acceptability in ALWR designs, based on the justification provided by a deterministic fracture mechanics analysis submitted as part of the design. The NRC concluded

that the analyses should be based on specific data, such as piping geometry, materials, and piping loads. However, the analyses may incorporate an initial set of bounding values and preliminary stress analysis results during the design certification phase. Subsequent verification of the preliminary analysis will be required.

The LBB approach has established certain limitations for excluding piping susceptible to failure from degradation mechanisms. In addition, the LBB introduced acknowledged inconsistency in the design basis, but the NRC published clarifications for the intended treatment of the containment, emergency core cooling systems, and environmental qualification in the LBB application.

The NRC position on LBB for the AP1000 is presented in SECY-95-172 (Reference 68).

AP1000 Response:

The AP1000 incorporates the leak-before-break approach for most high-energy lines inside containment that are 6 inches in diameter or larger. Detailed methodology and criteria are defined in subsection 3.6.3 and are consistent with those accepted by the NRC on existing nuclear power plants.

1.9.5.2.5 Classification of Main Steamline of Boiling Water Reactors (BWRs)

This issue is specific to BWRs and therefore does not apply to the AP1000 design.

1.9.5.2.6 Tornado Design Basis

NRC Position:

WASH-1300 (Reference 43) and Regulatory Guide 1.76 contain the current NRC regulatory position for design basis tornados. Based on a contractor review of Regulatory Guide 1.76, the NRC recommends a maximum tornado speed of 300 mph be used for design basis tornado for passive ALWR designs.

The tornado design basis requirements have been used in establishing structural requirements against effects not covered explicitly in review guidance such as Regulatory Guides or the SRP. The Combined License applicant will have to demonstrate that the design will also be sufficient to withstand other site hazards such as aviation crashes, nearby explosions, and explosion debris and missiles.

AP1000 Response:

The AP1000 is designed in accordance with the NRC recommendations for a maximum tornado wind speed of 300 mph, as described in Section 3.3. The AP1000 site interface defined in Chapter 2 provides that the Combined License applicant evaluate other site hazards if appropriate.

1.9.5.2.7 Containment Bypass

NRC Position:

Reasonable efforts should be made to minimize the possibility of containment bypass leakage, and ALWR designs should allow for a certain amount of leakage in the containment design. The NRC is evaluating the need for containment spray for all ALWRs. The containment spray provides containment temperature and pressure suppression effects and scrubs the containment atmosphere of fission products, mitigating the effects on the fission product bypass distribution.

AP1000 Response:

Although the phenomenon described for this item is primarily applicable to BWRs, the AP1000 has a variety of design features that help to reduce the potential for containment bypass leakage.

The response to the containment performance issue in subsection 1.9.5 provides additional information pertaining to various improvements that help to reduce containment bypass.

The safety-related passive containment cooling system design also contributes to the containment performance. The system includes multiple flow paths to provide cooling water for containment during severe accident conditions. The containment is also capable of successfully removing core decay heat with air-cooling alone.

The containment has a significantly reduced number of penetrations. The number of normally open containment penetrations is also reduced. The result is a low containment leak rate and a low probability of bypass.

The response to intersystem LOCA in subsection 1.9.5.1 provides additional information pertaining to applicable AP1000 design features that reduce the potential for intersystem LOCA and the potential for containment bypass.

Improvements are made to the steam generator design, such as the use of improved tube materials and tube supports. These improvements reduce the potential for tube leakage, which contributes to a reduction in containment bypass. Subsection 5.4.2 provides additional information on the steam generator design.

During a steam generator tube rupture event, the safety-related passive core cooling system automatically mitigates the effects of the event, including automatic safety-related protection against steam generator overfill.

The safety-related passive core cooling system provides long-term pH control for the containment sump, which helps to reduce the levels of airborne radioactivity, thereby reducing the consequences of leakage from the containment. Section 6.3 includes additional information on the passive core cooling system.

The diverse actuation system includes containment isolation features to provide isolation for the most risk-significant containment penetrations. PRA Chapter 24 discusses the provisions for isolating risk significant containment penetrations.

The performance of the passive fission product removal process and minimal potential for containment bypass precludes the need for a safety-related containment spray system on AP1000.

1.9.5.2.8 Containment Leak Rate Testing

NRC Position:

SECY-91-348 (Reference 44) proposes changes to 10 CFR 50, Appendix J to allow an increased interval from 24 months to 30 months for Type C containment leakage rate tests, until rule change proceedings are completed.

AP1000 Response:

10 CFR 50 Appendix J has been revised since SECY-91-348 was issued. AP1000 type C testing and compliance with 10 CFR 50 Appendix J is discussed in Section 6.2.5.

1.9.5.2.9 Post-Accident Sampling System

NRC Position:

Regulatory Guide 1.97 and NUREG-0737 (Reference 45) provide guidance regarding the design of the post-accident sampling system. 10 CFR 50.34 required the capability to obtain and analyze samples from containment and the reactor coolant system that may contain TID-14844 source term radioactive materials, without exceeding specified radiation exposures. The analysis and quantification are required for certain specified radionuclides that are indicators of the degree of core damage, containment hydrogen, dissolved gases, chloride, and boron concentrations.

The NRC concluded that adequate capability for monitoring post-accident hydrogen is provided by the safety-grade containment hydrogen monitoring instrumentation.

The NRC requires sampling the reactor coolant system for dissolved hydrogen, chloride, and oxygen. The time for taking these samples can be extended to 24 hours after the accident.

The NRC requires sampling the reactor coolant system for boron and for activity measurements. The time for taking these samples can be extended to 8 hours after power operation for boron and 24 hours after power operation for activity measurements.

AP1000 Response:

The post-accident sampling system is a subsystem of the primary sampling system, described in subsection 9.3.3.

The primary sampling system is designed to conform to the guidelines of the model Safety Evaluation Report on eliminating post-accident sampling system requirements from technical specifications for operating plants (Federal Register Volume 65, Number 211, October 31, 2000). The primary sampling system conforms with the most recent NRC position.

1.9.5.2.10 Level of Detail

NRC Position:

The Staff Requirements Memorandum for SECY-90-377 (Reference 47) provided guidance on the level of detail to be provided for a design certification application under 10 CFR 52. The guidance was that the application should include the information traditionally provided in a final safety analysis report, less the site-specific and as-procured information. This information should be supplemented by design inspections, tests, analysis, and acceptance criteria for those areas where the NRC is unable to make a final safety decision because of not having the site-specific information or the as-procured information, or because the technology is evolving so rapidly that it would be inappropriate to lock in the design.

AP1000 Response:

The AP1000 submittals are consistent with the requirements of 10 CFR 52 and the position in Reference 47.

1.9.5.2.11 Prototyping

NRC Position:

10 CFR 52.47 requires that sufficient data exist on the safety features of the design to assess the analytical tools used for safety analysis over a sufficient range of normal operating conditions, transient conditions, and specified accident conditions. Further, the interdependent effects among the safety features of the design must be found acceptable by analysis, appropriate test programs, experience, or a combination thereof. SECY-91-057 (Reference 48) informed the Commission of the steps the NRC was taking to identify the research needs for the AP600. SECY-91-074 (Reference 49) outlined the process the NRC would use to determine the need for a prototype or other demonstration facility for advanced reactor designs. SECY-91-273 (Reference 40) presented to the Commission the staff's recommendations for reviewing, monitoring and approving the Westinghouse test program to support the AP600 design certification application. SECY-92-030 (Reference 50) presented the Commission with the NRC opinion that there was a need for a full-height, full-pressure integral systems test to support the issuance of a final design approval.

AP1000 Response:

The Westinghouse testing program to assess the analytical methodologies used for the AP1000 safety analysis is described in Section 1.5 and is in conformance with the NRC position.

1.9.5.2.12 Inspections, Test, Analyses, and Acceptance Criteria (ITAAC)

NRC Position:

10 CFR 52 requires that the design certification application include the proposed tests, inspections, analyses, and the associated acceptance criteria. For certified standard designs, these tests, inspections, and analyses must apply to those portions of the facility covered by the design certification.

The Staff Requirements Memorandum for SECY-91-178 (Reference 51) provided guidance regarding development of ITAAC for final design approval and design certification applications.

AP1000 Response:

The AP1000 design certification application includes ITAACs.

1.9.5.2.13 Reliability Assurance Program

NRC Position:

SECY-89-013 (Reference 52) requires a reliability assurance program for design certification. The program would ensure that the design reliability of safety significant systems, structures, and components is maintained over the life of a plant.

The NRC is working on the development of a detailed guidance document consisting of two levels. The vendor submittal is the first level, consisting of a top-level program that identifies the scope, conceptual framework, and essential elements of an effective program. The Combined License applicant fully develops and implements the program based on the plant-specific design information.

AP1000 Response:

Section 16.2 includes a description of the reliability assurance program. The program description identifies the scope, conceptual framework, and essential elements of the program. The reliability assurance program confirms that the performance of the safety-related systems, structures, and components is consistent with the assumptions made for the design basis analysis.

In addition, the reliability assurance program monitors the long-term performance of important nonsafety-related structures, systems, and components that provide defense-in-depth against unnecessary actuation of the passive safety-related systems.

1.9.5.2.14 Site-Specific Probabilistic Risk Assessments (PRAs)

NRC Position:

10 CFR 52.47 requires all applicants for standard design certification to provide a PRA with enveloping analyses for seismic events and tornadoes. The Combined License applicant is responsible for the site-specific PRA information that addresses site-specific events such as river flooding, storm surge, tsunami, volcanism, and hurricanes.

AP1000 Response:

The AP1000 PRA submitted as a part of the design certification application is based on a site that bounds a large percentage of plant sites in the United States and is described in Chapter 2. The information in the AP1000 PRA evaluation is available to the Combined License applicant to develop a PRA evaluation that addresses site-specific hazards.

1.9.5.2.15 Severe Accident Mitigation Design Alternatives

NRC Position:

The National Environmental Policy Act (NEPA) requires that alternatives be investigated for actions that may significantly affect the quality of the human environment. The timing of the NEPA hearing is at the Early Site Permit or Combined License stage. One objective of the 10 CFR 52 design certification rulemaking is to preclude changes to a certified standard plant design. The U.S. Court of Appeals has required the NRC to include consideration of severe accident mitigation design alternatives (SAMDAs) as a part of their environmental impact review for operating license applications. If this same process is followed for a plant design that had been certified, it may be necessary to reopen issues that had been resolved in the design certification rulemaking. To avoid this situation, the NRC issued SECY-91-229 (Reference 53) which recommended that SAMDAs be specifically addressed during the design certification rulemaking.

AP1000 Response:

The severe accident mitigation design alternatives (SAMDA) evaluation for AP1000 is contained in Appendix 1B.

1.9.5.2.16 Generic Rulemaking Related to Design Certification

NRC Position:

SECY-91-262 (Reference 54) provides the NRC recommendations to proceed with design-specific rulemaking where appropriate for passive designs, as information becomes available from ongoing efforts on those issues, independent of the design review and certification processes. In SECY-93-087 the NRC staff concludes that the design of passive plants is not sufficiently developed to determine whether generic rulemaking should be initiated for passive plant designs.

Generic rulemaking activities for source terms during severe accidents are ongoing, and the results may be used during design certification of the passive plants, focusing on updating 10 CFR 100 siting criteria, and planning to incorporate the revised source criteria in 10 CFR 50.

AP1000 Response:

No response necessary. See subsection 1.9.5.1.1 for a discussion of the use of a physically based source term.

1.9.5.3 Passive Design Issues

Issues related to the passive design were outlined in Reference 30.

1.9.5.3.1 Regulatory Treatment of Non-Safety Systems

NRC Position:

The NRC believes that its review of passive designs requires not only a review of the passive safety-related systems, but also a review of the functional capability and availability of the active nonsafety-related systems to provide significant defense-in-depth and accident and core damage prevention capability. The NRC issued a commission policy paper SECY-94-084 (Reference 67), on the regulatory treatment of non-safety systems (RTNSS), that outlines the process for resolving the RTNSS issue. This process includes a combination of probabilistic and deterministic criteria to identify risk-significant nonsafety-related systems.

AP1000 Response:

The AP1000 nonsafety-related active systems are designed to provide reliable support for normal plant operations and to provide defense-in-depth to minimize unnecessary challenges to the safety-related passive systems. These active systems are designed for more probable component and system failures. The systems include reliable, proven equipment and component designs. These active systems are capable of being powered by the nonsafety-related diesel-generators. The systems have nonsafety-related automatic actuation and controls that are separate from those of the safety-related systems.

These systems are designed to provide highly reliable performance. The design standards and operability provisions for these systems are discussed in subsection 3.2.2.6. Availability controls were developed for nonsafety related structures, systems, and components found to the important via the RTNSS process. The availability controls for the AP1000 are documented in DCD Section 16.3 and are the same as those for the AP600.

1.9.5.3.2 Definition of Passive Failure

NRC Position:

The NRC considered redefining failure of check valves in passive safety systems, where the valve fails to provide the mechanical movement to complete its intended safety function, to that of an active failure, as defined in Appendix A to 10 CFR 50. The NRC was concerned, since safety-related check valves in passive designs operate under different conditions (low flow and pressure without pump pressure to open valves) than current generation reactors and evolutionary designs. The check valves have increased safety significance to the operation of the passive safety-related systems, and operating experience has shown that they have a lower reliability than originally anticipated. The Staff position is described in SECY-94-084 (Reference 67).

AP1000 Response:

AP1000 is designed to tolerate the single failure of a check valve to change position to perform a safety-related function. Valve redundancy is provided for the core makeup tank discharge check valves (to close), the in-containment refueling water storage tank gravity injection check valves (to open), the containment recirculation gravity injection check valves (to open), and containment isolation line check valves (to close). The redundancy in the design for each of these safety-related

flow paths is sufficient to accommodate the single failure of a check valve to reposition as required to perform its safeguards function.

Section 6.3 provides additional information on the failures assumed for the passive core cooling system including exceptions to the single failure criteria.

1.9.5.3.3 SBWR Stability

This issue is applicable to BWRs only.

1.9.5.3.4 Safe Shutdown Requirements

NRC Position:

GDC 34 requires that a residual heat removal system be provided to remove residual heat from the reactor core so that specified, acceptable fuel design limits are not exceeded. Regulatory Guide 1.139 and Branch Technical Position 5-1 implement this requirement and set forth conditions to cold shutdown (200°F for a PWR) using only safety-related systems within 36 hours.

The NRC evaluated the alternate means of addressing GDC 34 using passive safety-related systems to achieve a safe shutdown condition of 420°F. Additionally, the NRC reviewed the acceptability of using active, nonsafety-related systems to take a plant to cold shutdown conditions. The results of this review are presented in SECY-94-084 (Reference 67).

AP1000 Response:

The AP1000 includes safety-related passive systems and equipment that are designed to automatically establish and indefinitely maintain safe shutdown conditions for the plant following design basis events.

Sections 6.3 and 7.4 provide additional information pertaining to safe shutdown, using the safety-related passive systems.

1.9.5.3.5 Control Room Habitability

NRC Position:

10 CFR 50, Appendix A, GDC 19 requires adequate radiation protection to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of five rem whole body, or its equivalent, to any part of the body, for the duration of the accident. Section 6.4 of the Standard Review Plan defines this dose criterion in terms of specific whole-body and organ doses (5 rem to whole body, and 30 rem each to thyroid and skin). The NRC requires that the analyses of main control room habitability be based on the dose criterion defined in GDC 19 of Appendix A to 10 CFR 50 and Section 6.4 of the Standard Review Plan (5 rem to whole body, and 30 rem each to thyroid and skin). In addition, the analyses of control room habitability should be based on the duration of the accident according to GDC 19 of Appendix A to 10 CFR 50.

AP1000 Response:

The AP1000 design includes a passive, safety-related main control room habitability system to meet the requirements of GDC 19. Section 6.4 provides additional information.

As described in subsection 15.6.5.3, the main control room operator doses following a design basis loss of coolant accident are within the dose criterion of GDC 19 (5 rem TEDE as applied to the AP1000 design).

1.9.5.3.6 Radionuclide Attenuation

NRC Position:

The NRC is concerned that use of the auxiliary building for holdup may require additional restrictions to be placed on the auxiliary building during normal operation. In addition, the NRC is continuing its evaluation of the need for a containment spray system for passive plant designs.

AP1000 Response:

The AP1000 design does not have a safety-related containment spray or take credit for auxiliary building holdup for mitigation of the design basis loss of coolant accident. The design includes a low-leakage-rate containment (0.10 percent per day) together with credit for aerosol removal by naturally occurring processes and pool scrubbing in containment. The low-leakage containment and natural aerosol removal are adequate to meet 10 CFR 100 dose limits, consistent with the physically-based source term.

1.9.5.3.7 Simplification of Off-Site Emergency Planning

NRC Position:

The NRC states that changes to emergency planning regulatory requirements may be appropriate, but that an NRC determination on this issue will require detailed design evaluation. Summaries of specific NRC conclusions are as follows:

- Unique characteristics of the designs should be considered in determining the extent of emergency planning, including the ability to prevent significant release of radioactive material or to provide delay times for all but the most unlikely events.

- A very low likelihood of all containment bypass sequences will be required before relaxing emergency planning requirements.

- Lack of information on source term and risk precludes further NRC evaluation of emergency preparedness for the passive plants at this time.

- Emergency planning requirements following the TMI-2 accident were not premised on specific assumptions regarding severe accident probability. So, as a policy matter, even very low calculated probabilities may not be a sufficient basis for changes to emergency planning requirements.

The industry and the NRC are working to determine a process, including developing technical criteria and methods, that would justify simplification of offsite emergency planning. The results of this process would be used as input to a generic rulemaking proposal to be initiated by nuclear industry organizations.

AP1000 Response:

The AP1000 PRA evaluation risk assessment includes calculations of the AP1000 response to severe accidents. This response includes the release of radionuclides following a severe accident. This analysis supports the technical basis for simplification of offsite emergency planning. The offsite emergency planning is the responsibility of the Combined License applicant.

1.9.5.4 Additional Licensing Issue

Post-72 Hour Support Actions

The AP1000 includes safety-related passive systems and equipment that are sufficient to automatically establish and maintain safe shutdown conditions for the plant following design basis events, assuming that the most limiting single failure occurs. The safety-related passive systems maintain safe shutdown conditions after an event -- without operator action, without onsite and offsite ac power sources.

The AP1000 includes nonsafety-related active systems and equipment designed to provide multiple levels of defense for a wide range of events. For the more probable events, these nonsafety-related systems automatically actuate to provide a first level of defense to reduce the likelihood of unnecessary actuation and operation of the safety-related passive systems. These nonsafety-related systems establish and maintain safe shutdown conditions for the plant following design basis events, provided that at least one of the standby nonsafety-related ac power sources is available.

Although event scenarios that result in an extended loss of the nonsafety-related systems or both offsite and onsite ac power sources for more than 72 hours are very unlikely, this potential is considered in the AP1000 design.

The actions described below are required following an extended loss of these nonsafety-related systems.

The safety functions required include the following:

- Core cooling, inventory, and reactivity control
- Containment cooling and ultimate heat sink
- Main control room habitability and post-accident monitoring
- Spent fuel pool cooling

Based on these safety-related functions, the AP1000 design includes both onsite equipment and safety-related connections for use with transportable equipment and supplies to provide the following extended support actions:

- Provide electrical power to supply the post-accident and spent fuel pool monitoring instrumentation, using the ancillary diesel generators or a portable, engine-driven ac generator that connects to safety-related electrical connections. See Section 8.3 for additional information.

- Provide makeup water to the passive containment cooling water storage tank to maintain external containment cooling water flow, using one of the two PCS recirculation pumps powered by an ancillary diesel generator or a portable, engine-driven pump that connects to a safety-related makeup connection. See subsection 6.2.2 for additional information.

- Ventilation and cooling of the main control room, the instrumentation and control rooms, and the dc equipment rooms is provided by open doors and ancillary fans or portable fans powered by an ancillary diesel generator or a portable, engine-driven ac generator.

- Provide makeup water to the spent fuel pool from the passive containment cooling water storage tank, passive containment cooling water ancillary water storage tank, and from the long term makeup connection. See subsection 6.2.2.4 for a discussion of the operation of the passive containment cooling system and subsection 9.1.3.4.3 and 9.1.3.5 for discussion of makeup to the spent fuel pool.

- Provide a vent path between the fuel handling area and outside environment to vent water vapor generated by elevated spent fuel pool water temperature. See subsection 9.1.3.4.3.4 for additional information.

These actions are accomplished by the site support personnel, in coordination with the main control room operators. These actions are performed separate from, but in parallel with, other actions taken by the plant operators to directly mitigate the consequences of an event.

1.9.5.5 Operational Experience

Operational experience highlighted in NRC bulletins, generic letters, and information notices has been incorporated into the AP1000 design. Generic letters and bulletins are identified in WCAP-15800 (Reference 65). The applicability of each generic letter and bulletin to the AP1000 is assessed in WCAP-15800. If required, additional information for applicable issues is provided in the referenced sections of the DCD.

1.9.6 References

1. NUREG-0696, "Functional Criteria for Emergency Response Facilities," 1981.

2. Report NP-2770-LD, "EPRI PWR Safety Valve Test Report," December 1982.

3. NUREG-0933, "A Prioritization of Generic Safety Issues," June 2001.

4. NUREG-0371, "Task Action Plans for Generic Activities (Category A)," U.S. Nuclear Regulatory Commission, November 1978.

5. NUREG-0927, Revision 1, "Evaluation of Water Hammer Occurrences in Nuclear Power Plants," U.S. Nuclear Regulatory Commission, March 1984.

6. NRC letter to all PWR Licensees of Operating Reactors, Applicants for Operating Licensees and Holders of Construction Permits, and Ft. St. Vrain, "Staff Recommended Actions Stemming from NRC Integrated Program for the Resolution of Unresolved Safety Issues Regarding Steam Generator Tube Integrity," (Generic Letter 85-02) April 17, 1985.

7. NUREG-0844, "NRC Integrated Program for the Resolution of Unresolved Safety Issues A-3, A-4, A-5 Regarding Steam Generator Tube Integrity," U.S. Nuclear Regulatory Commission, September 1988.

8. NUREG-0577, Revision 1, "Potential for Low Fracture Toughness and Lamellar Tearing in PWR Steam Generator and Reactor Coolant Pump Supports," U.S. Nuclear Regulatory Commission, October 1983.

9. IEEE 323-1974, "Qualifying Class 1E Equipment for Nuclear Power Generating Stations," Institute of Electrical and Electronics Engineers.

10. NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," U.S. Nuclear Regulatory Commission, July 1980.

11. NUREG-0510, "Identification of Unresolved Safety Issues Relating to Nuclear Power Plants," U.S. Nuclear Regulatory Commission, January 1979.

12. NUREG-0705, "Identification of New Unresolved Safety Issues Relating to Nuclear Power Plant Stations," U.S. Nuclear Regulatory Commission, February 1981.

13. IEEE 344-1987, "Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations," Institute of Electrical and Electronics Engineers.

14. NUREG-0410, "NRC Program for the Resolution of Generic Issues Related to Nuclear Power Plants."

15. NUREG-0660, "NRC Action Plan Developed as a result of the TMI-2 accident," May 1980.

16. NUREG-0985, "Nuclear Regulatory Commission Human Factors Program Plan Revision 2," April 1986.

17. IEEE 384-1981, "IEEE Standard Criteria for Independence of Class 1E Equipment and Circuits," Institute of Electrical and Electronics Engineers.

18. NUREG-0471, "Generic Task Problem Descriptions (Category B, C, and D Tasks)" and NUREG-0933, "A Prioritization of Generic Safety Issues," June 1978.

19. NUREG-0484, Revision 1, "Methodology for Combining Dynamic Responses," May 1980.

20. IEEE 317-1983, "Standard for Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations," Institute of Electrical and Electronics Engineers.

21. ANSI/ANS-58.8-1984. "Time Response Design Criteria for Nuclear Safety Related Operator Actions."

22. NUREG/CR-2425, "Sediment and Radionuclide Transport in Rivers," December 1982.

23. NUREG-0693, "Analysis of Ultimate-Heat-Sink Cooling Ponds," November 1980.

24. NUREG-0733, "Analysis of Ultimate Heat-Sink Spray Ponds," August 1981.

25. NUREG-0858, "Comparison Between Field Data and Ultimate Heat Sink Cooling-Pond and Spray-Pond Models," September 1980.

26. ANSI 5.1, "Decay Heat Power in Light Water Reactors," American National Standards Institute, 1979.

27. NUREG-0691, "Investigation and Evaluation of Cracking Incidents in Piping in Pressurized Water Reactors," September 1980.

28. ANSI 56.5-1979, "PWR and BWR Containment Spray System Design Criteria."

29. USNRC, SECY-90-016, "Evolutionary Light Water Reactor (LWR) Certification Issues And Their Relationship to Current Regulatory Requirements," January 12, 1990.

30. NRC letter, Subject: Identification of Issues Concerning the Evolutionary and Passive Plant Designs, Dennis M. Crutchfield, USNRC Director, Division of Advanced Reactors and Special Projects, to E. E. Kintner, Chairman ALWR Steering Committee, February 27, 1992.

31. Staff Requirements Memorandum, Subject: SECY-90-016 - Evolutionary Light Water Reactor (LWR) Certification Issues and Their Relationship to Current Regulatory Requirements, Samuel J. Chilk, USNRC Secretary, to James M. Taylor, USNRC Executive Director for Operations, June 26, 1990.

32. NUREG-1150, "Severe Accident Risk: An Assessment for Five U.S. Nuclear Power Plants," June 1989.

33. "Passive ALWR Source Term," D. E. Leaver, et al., DOE/ID-10321, February 1991.

34. NUREG-0649, "Task Action Plans for Unresolved Safety Issues Related to Nuclear Power Plants," Revision 1, September 1984.

35. NUREG-1032, "Evaluation of Station Blackout Accidents at Nuclear Power Plants, Technical Findings Related to Unresolved Safety Issue A-44," June 1988.

36. NUREG-1109, "Regulatory/Backfit Analysis for the Resolution of Unresolved Safety Issue A-44, Station Blackout," June 1988.

37. Branch Technical Position CMEB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants," July 1986.

38. Generic Letter 89-04, "Guidance on Developing Acceptable Inservice Testing Programs," April 3, 1989.

39. Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," June 28, 1989.

40. SECY-91-273, "Review of Vendors' Test Programs to Support the Design Certification of Passive Light Water Reactors," August 27, 1991.

41. SECY-91-078, "Chapter 11 of EPRI's Requirements Document and Additional Evolutionary Light Water Reactor Certification Issues," March 25, 1991.

42. NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," June 1991.

43. WASH-1400 (NUREG-75/014), "Reactor Safety Study, An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," October 1975.

44. SECY-91-348, preliminary untitled SECY related to containment leakrate testing, issued to the Commission for review, and not yet released by the NRC.

45. NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

46. NUREG-4330, "Review of Light Water Reactor Regulatory Requirements, Volume 1, Identification of Regulatory Requirements That May Have Marginal Importance to Risk," April 1986.

47. SECY-90-377, "Requirements for Design Certification Under 10 CFR Part 52," November 8, 1990.

48. SECY-91-057, "Early Review of AP600 and SBWR Research Needs," March 1, 1991.

49. SECY-91-074, "Prototype Decisions for Advanced Reactor Designs," March 19, 1991.

50. SECY-92-030, "Integral System Testing Requirements for Westinghouse's AP600 Plant," January 27, 1992.

51. SECY-91-178, "Inspections, Tests, Analyses, and Acceptance Criteria (ITAAC) for Design Certifications and Combined Licenses," June 12, 1991.

52. SECY-89-013, "Design Requirements Related to the Evolutionary Advanced Light Water Reactors (ALWRs)," January 19, 1989.

53. SECY-91-229, "Severe Accident Mitigation Design Alternatives for Certified Standard Designs," July 31, 1991.

54. SECY-91-262, "Resolution of Selected Technical and Severe Accident Issues for Evolutionary Light Water Reactor (LWR) Designs," August 16, 1991.

55. Not used.

56. WCAP-15993, "Evaluation of the AP1000 Conformance to Inter-System Loss-of-Coolant Accident Acceptance Criteria," Revision 1, March 2003.

57. SECY-95-172, "Key Technical Issues Pertaining to the Westinghouse AP600 Standardized Passive Reactor Design," June 30, 1995.

58. NUREG-1465, "Accident Source Terms for Light-Water Nuclear Power Plants," L. Soffer, et al., February 1995.

59. SECY-94-302, "Source Term-Related Technical and Licensing Issues Pertaining to Evolutionary and Passive Light-Water-Reactor Designs," December 19, 1994.

60. SECY-94-194, "Proposed Revisions to 10 CFR Part 100 and 10 CFR Part 50, and New Appendix S to 10 CFR Part 50," July 27, 1994.

61. Not used.

62. Theofanous, T. G., et al., "In-Vessel Coolability and Retention of a Core Melt," DOE/ID-10460, July 1995.

63. WCAP-15799, "AP1000 Compliance with SRP Acceptance Criteria," Revision 1, August 2003.

64. NCRP Report No. 116, Limitation of Exposure to Ionizing Radiation, March 31, 1993.

65. WCAP-15800, "Operational Assessment for AP1000," Revision 3, July 2004.

66. SECY-98-161, "The Westinghouse AP1000 Standard Design as it Relates to the Fire Protection and the Spent Fuel Pool Cooling Systems," July 1, 1998.

67. SECY-94-084, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems in Passive Plant Designs," March 28, 1994.

68. SECY-95-172, "Key Technical Issues Pertaining to the Westinghouse AP1000 Standardized Passive Reactor Design," June 30, 1995.

69. WCAP-15992, "AP1000 Adverse Systems Interactions Evaluation Report," Revision 1, February 2003.

70. WCAP-15776, "Safety Criteria for the AP1000 Instrumentation and Control Systems," April 2002.

Table 1.9-1 (Sheet 1 of 15)

REGULATORY GUIDE/DCD SECTION CROSS-REFERENCES

Division 1 Regulatory Guide		DCD Chapter, Section or Subsection
1.1	Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps (Rev. 0, November 2, 1970)	This regulatory guide is not applicable to AP1000.
1.2	Withdrawn	
1.3	Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-coolant Accident for Boiling Water Reactors (Rev. 2, June 1974)	This regulatory guide is not applicable to AP1000.
1.4	Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors (Rev. 2, June 1974)	The guidance of Reg. Guide 1.183, “Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors” will be followed instead of Reg. Guide 1.4.
1.5	Assumptions Used for Evaluating the Potential Radiological Consequences of a Steam Line Break Accident for Boiling Water Reactors (Rev. 0, March 10, 1971)	This regulatory guide is not applicable to AP1000.
1.6	Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems (Rev. 0, March 10, 1971)	8.1 8.3.1 8.3.2
1.7	Control of Combustible Gas Concentration in Containment Following a Loss-of-Coolant Accident (Rev. 2, November 1978)	6.1.1 6.2.4 15.6.3 Appendix 15A
1.8	Qualification and Training of Personnel for Nuclear Power Plants (Rev. 3, 1 May 2000)	This regulatory guide is not applicable to AP1000 design certification.
1.9	Selection, Design, and Qualification of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants (Proposed Rev. 3, November 1988)	This regulatory guide is not applicable to AP1000.
1.10	Withdrawn	
1.11	Instrument Lines Penetrating Primary Reactor Containment (Rev. 0, March 10, 1971)	3.6.2 6.2.3
1.12	Instrumentation for Earthquakes (Rev. 2, March 1997)	3.7.4
1.13	Spent Fuel Storage Facility Design Basis (Proposed Rev. 2, December 1981)	9.1.2 9.1.3 9.1.4

Table 1.9-1 (Sheet 2 of 15)

REGULATORY GUIDE/DCD SECTION CROSS-REFERENCES

Division 1 Regulatory Guide		DCD Chapter, Section or Subsection
1.14	Reactor Coolant Pump Flywheel Integrity (Rev. 1, August 1975)	5.4.1
1.15	Withdrawn	
1.16	Reporting of Operating Information - Appendix A Technical Specifications (Rev. 4, August 1975).	This regulatory guide is not applicable to AP1000 design certification.
1.17	Withdrawn	
1.18	Withdrawn	
1.19	Withdrawn	
1.20	Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing (Rev.2, May 1976)	3.9.2 14
1.21	Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents From Light-Water-Cooled Nuclear Power Plants (Rev. 1, June 1974)	11.5
1.22	Periodic Testing of Protection System Actuation Functions (Rev. 0, February 17, 1972)	7.1 7.2 7.4
1.23	Onsite Meteorological Program (Second Proposed Rev. 1, April 1986)	2.3
1.24	Assumptions Used for Evaluating the Potential Radiological Consequences of a Pressurized Water Reactor Radioactive Gas Storage Tank Failure (Rev. 0, March 23, 1972)	This regulatory guide is not applicable to AP1000.
1.25	Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors (Rev. 0, March 23, 1972)	The guidance of Reg. Guide 1.183, “Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors” will be followed instead of Reg. Guide 1.25.
1.26	Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants (Rev. 3, February 1976)	3.2.2
1.27	Ultimate Heat Sink for Nuclear Power Plants (Rev. 2, January 1976)	6.2.2
1.28	Quality Assurance Program Requirements (Design and Construction) (Rev. 3, August 1985)	2.5 17
1.29	Seismic Design Classification (Rev. 3, September 1978)	3.2.1

Table 1.9-1 (Sheet 3 of 15)

REGULATORY GUIDE/DCD SECTION CROSS-REFERENCES

Division 1 Regulatory Guide		DCD Chapter, Section or Subsection
1.30	Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment (Rev. 0, August 11, 1972)	This regulatory guide is not applicable to AP1000 design certification.
1.31	Control of Ferrite Content in Stainless Steel Weld Metal (Rev. 3, April 1978)	4.5.1 4.5.2 5.2.3 5.3.2 6.1.1
1.32	Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants (Rev. 2, February 1977)	8.1 8.2 8.3.1 8.3.2
1.33	Quality Assurance Program Requirements (Operation) (Second Proposed Rev. 3, November 1980)	This regulatory guide is not applicable to AP1000 design certification.
1.34	Control of Electroslag Weld Properties (Rev. 0, December 28, 1972)	4.5.2 5.2.3 5.3.2
1.35	Inservice Inspection of Ungrouted Tendons in Pre-stressed Concrete Containments (Rev. 3, July 1990)	This regulatory guide is not applicable to AP1000.
1.35.1	Determining Prestressing Forces for Inspection of Prestressed Concrete Containments (Rev. 0, July 1990)	This regulatory guide is not applicable to AP1000.
1.36	Nonmetallic Thermal Insulation for Austenitic Stainless Steel (Rev. 0, February 23, 1973)	5.2.3 6.1.1
1.37	Quality Assurance Requirements for cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants (Rev. 0, March 1973)	17
1.38	Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (Rev. 2, May 1977)	17
1.39	Housekeeping Requirements for Water-Cooled Nuclear Power Plants (Rev. 2, September 1977)	17
1.40	Qualification Tests of Continuous-Duty Motors Installed Inside the Containment of Water-Cooled Nuclear Power Plants (Rev. 0, March 16, 1973)	This regulatory guide is not applicable to AP1000.

Table 1.9-1 (Sheet 4 of 15)

REGULATORY GUIDE/DCD SECTION CROSS-REFERENCES

Division 1 Regulatory Guide		DCD Chapter, Section or Subsection
1.41	Preoperational Testing of Redundant Onsite Electric Power Systems to Verify Proper Load Group Assignments (Rev. 0, March 16, 1973)	14
1.42	Withdrawn	
1.43	Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components (Rev. 0, May 1973)	5.2.3 5.3.2
1.44	Control of the Use of Sensitized Stainless Steel (Rev. 0, May 1973)	4.5.1 4.5.2 5.2.3 5.3.2 6.1.1 10.3
1.45	Reactor Coolant Pressure Boundary Leakage Detection Systems (Rev. 0, May 1973)	5.2.5
1.46	Withdrawn	
1.47	Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems (Rev. 0, May 1973)	6.3 7.2 7.3 7.4 7.5 8.3.2
1.48	Withdrawn	
1.49	Power Levels of Nuclear Power Plants (Rev. 1, December 1973)	16
1.50	Control of Preheat Temperature for Welding of Low-Alloy Steel (Rev. 0, May 1973)	5.2.3 5.3.2 6.1.1
1.51	Withdrawn	
1.52	Design, Testing, and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants (Rev. 2, March 1978)	6.5.1

Table 1.9-1 (Sheet 5 of 15)

REGULATORY GUIDE/DCD SECTION CROSS-REFERENCES

Division 1 Regulatory Guide		DCD Chapter, Section or Subsection
1.53	Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems (Rev. 0, June 1973)	7.1 7.2 7.4 15.2 15.3 15.4 15.5 15.6
1.54	Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants (Rev. 1, July 2000)	6.1.2
1.55	Withdrawn	
1.56	Maintenance of Water Purity in Boiling Water Reactors (Rev. 1, July 1978)	This regulatory guide is not applicable to AP1000.
1.57	Design Limits and Loading Combinations for Metal Primary Reactor Containment System Components (Rev. 0, June 1973)	3.8.2 3.8.3
1.58	Withdrawn	
1.59	Design Basis Floods for Nuclear Power Plants (Rev. 2, August 1977)	2.4 3.4
1.60	Design Response Spectra for Seismic Design of Nuclear Power Plants (Rev. 1, December 1973)	2.5 3.7.1
1.61	Damping Values for Seismic Design of Nuclear Power Plants (Rev. 0, October 1973)	3.7.1 3.9.23.10
1.62	Manual Initiation of Protective Actions (Rev. 0, October 1973)	7.1 7.2
1.63	Electric Penetration Assemblies in Containment Structures for Nuclear Power Plants (Task EE 405-4) (Rev. 3, February 1987)	8.3.1
1.64	Withdrawn	
1.65	Materials and Inspections for Reactor Vessel Closure Studs (Rev. 0, October 1973)	5.3.2
1.66	Withdrawn	
1.67	Withdrawn	

Table 1.9-1 (Sheet 6 of 15)

REGULATORY GUIDE/DCD SECTION CROSS-REFERENCES

Division 1 Regulatory Guide		DCD Chapter, Section or Subsection
1.68	Initial Test Programs for Water-Cooled Nuclear Power Plants (Rev. 2, August 1978)	14
1.68.1	Preoperational and Initial Startup Testing of Feedwater and Condensate Systems for Boiling Water Reactor Power Plants (Rev. 1, January 1977)	This regulatory guide is not applicable to AP1000.
1.68.2	Initial Test Program to Demonstrate Remote Shutdown Capability for Water-Cooled Nuclear Power Plants (Rev. 1, July 1978)	14
1.68.3	Preoperational Testing of Instrument and Air Control Systems (Task RS 709-4) (Rev. 0, April 1982)	9.3.1 14
1.69	Concrete Radiation Shields for Nuclear Power Plants (Rev. 0, December 1973)	3.8.4 12.3
1.70	Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants (Rev. 3, November 1978)	1.1
1.71	Welder Qualification for Areas of Limited Accessibility (Rev. 0, December 1973)	5.2.3.4.6
1.72	Spray Pond Piping Made From Fiberglass-Reinforced Thermosetting Resin (Rev. 2, November 1978)	This regulatory guide is not applicable to AP1000.
1.73	Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants (Rev.0, January 1974)	3.11
1.74	Withdrawn	
1.75	Physical Independence of Electric Systems (Rev. 2, September 1978)	7.1 7.2 7.3 7.4 7.5 8.1 8.3.1 8.3.2 9.5.1
1.76	Design Basis Tornado for Nuclear Power Plants (Rev. 0, April 1974)	2.3 3.3

Table 1.9-1 (Sheet 7 of 15)

REGULATORY GUIDE/DCD SECTION CROSS-REFERENCES

Division 1 Regulatory Guide		DCD Chapter, Section or Subsection
1.77	Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors (Rev. 0, May 1974)	The guidance of Reg. Guide 1.183, "Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors" will be followed instead of Reg. Guide 1.77.
1.78	Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release (Rev. 1, December 2001)	2.2 6.4 9.4.1 9.5.1
1.79	Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors (Rev. 1, September 1975)	14
1.80	Withdrawn	
1.81	Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plant (Rev. 1, January 1975)	This regulatory guide is not applicable to AP1000.
1.82	Water Sources for Long Term Recirculation Cooling Following a Loss-of-Coolant Accident (Task 203-4) (Rev. 2, May, 1996)	6.3
1.83	Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes (Rev. 1, July 1975)	5.4.2
1.84	Design and Fabrication Code Case Acceptability ASME Section III Division 1 (Rev. 32, June 2003)	4.5.1 4.5.2 5.2.1 5.2.3 10.3
1.85	Withdrawn	
1.86	Termination of Operating Licenses for Nuclear Reactors (Rev. 0, June 1974)	This regulatory guide is not applicable to AP1000 design certification.
1.87	Guidance for Construction of Class 1 Components in Elevated-Temperature Reactors (Rev. 1, June 1975)	This regulatory guide is not applicable to AP1000.
1.88	Withdrawn	

Table 1.9-1 (Sheet 8 of 15)

REGULATORY GUIDE/DCD SECTION CROSS-REFERENCES

Division 1 Regulatory Guide		DCD Chapter, Section or Subsection
1.89	Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants (Task EE 042-2) (Rev. 1, June 1984)	3.11
1.90	Inservice Inspection of Prestressed Concrete Containment Structures With Grouted Tendons (Rev. 1, August 1977)	This regulatory guide is not applicable to AP1000.
1.91	Evaluations of Explosions Postulated to Occur on Transportation Routes Near Nuclear Power Plant Sites (Rev. 1, February 1978)	This regulatory guide is not applicable to AP1000 design certification.
1.92	Combining Modal Responses and Spatial Components in Seismic Response Analysis (Rev. 1, February 1976)	3.7
1.93	Availability of Electric Power Sources (Rev. 0, December 1974)	8.1 8.3
1.94	Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants (Rev. 1, April 1976)	This regulatory guide is not applicable to AP1000 design certification.
1.95	Withdrawn	
1.96	Design of Main Steam Isolation Valve Leakage Control Systems for Boiling Water Reactor Nuclear Power Plants (Rev. 1, June 1976)	This regulatory guide is not applicable to AP1000.
1.97	Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident (Rev. 3, May 1983)	7.5 18.8
1.98	Assumptions Used for Evaluating the Potential Radiological Consequences of a Radioactive Offgas System Failure in a Boiling Water Reactor (Rev. 0, March 1976)	This regulatory guide is not applicable to AP1000.
1.99	Radiation Embrittlement of Reactor Vessel Materials (Task ME 305-4) (Rev. 2, May 1988)	5.3.2 5.3.3
1.100	Seismic Qualification of Electric and Mechanical Equipment for Nuclear Power Plants (Task EE 108-5) (Rev. 2, June 1988)	3.10
1.101	Emergency Planning and Preparedness for Nuclear Power Reactors (Rev. 3, August 1992)	This regulatory guide is not applicable to AP1000 design certification.
1.102	Flood Protection for Nuclear Power Plants (Rev. 1, September 1976)	3.4

Table 1.9-1 (Sheet 9 of 15)

REGULATORY GUIDE/DCD SECTION CROSS-REFERENCES

Division 1 Regulatory Guide		DCD Chapter, Section or Subsection
1.103	Withdrawn	
1.104	Withdrawn	
1.105	Instrument Setpoints for Safety-Related Systems (Task 1C 010-5) (Rev. 3, December 1999)	7.1 16
1.106	Thermal Overload Protection for Electric Motors on Motor-Operated Valves (Rev. 1, March 1977)	8.1
1.107	Qualifications for Cement Grouting Tendons for Prestressing Tendons in Containment Structures (Rev. 1, February 1977)	This regulatory guide is not applicable to AP1000.
1.108	Withdrawn	
1.109	Calculation of Annual Doses to Man From Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance With 10 CFR Part 50 Appendix I (Rev. 1, October 1977)	11.3.3
1.110	Cost-Benefit Analysis for Radwaste Systems for Light-Water-Cooled Nuclear Power Reactors (Rev. 0, March 1976)	11.2 11.3
1.111	Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases From Light-Water-Cooled Reactors (Rev. 1, July 1977)	2.3
1.112	Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents From Light-Water-Cooled Power Reactors (Rev. 0-R, May 1977)	11.2.3 11.3.3
1.113	Estimating Aquatic Dispersion of Effluents From Accidental and Routine Reactor Releases for the Purpose of Implementing Appendix I (Rev. 1, April 1977)	This regulatory guide is not applicable to AP1000 design certification.
1.114	Guidance to Operators at the Controls and to Senior Operators in the Control Room of a Nuclear Power Unit (Rev. 2, May 1989)	This regulatory guide is not applicable to AP1000 design certification.
1.115	Protection Against Low-Trajectory Turbine Missiles (Rev 1, July 1977)	3.5 3.8.4
1.116	Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems (Rev.)-R, May 1977)	This regulatory guide is not applicable to AP1000 design certification.
1.117	Tornado Design Classification (Rev. 1, April 1978)	3.5 9.1.2

Table 1.9-1 (Sheet 10 of 15)

REGULATORY GUIDE/DCD SECTION CROSS-REFERENCES

Division 1 Regulatory Guide		DCD Chapter, Section or Subsection
1.118	Periodic Testing of Electric Power and Protection Systems (Rev. 3, April 1995)	7.1 8.1 8.3
1.119	Withdrawn	
1.120	Fire Protection Guidelines for Nuclear Power Plants (Rev. 1, November 1977)	9.5.1
1.121	Bases for Plugging Degraded PWR Steam Generator Tubes (Rev. 0, August 1976)	5.4.2
1.122	Development of Floor Design Response Spectra for Seismic Design of Floor-Supported Equipment or Components (Rev. 1, February 1978)	3.7
1.123	Withdrawn	
1.124	Service Limits and Loading Combinations for Class 1 Linear-Type Component Supports (Rev. 1, January 1978)	3.9.3
1.125	Physical Models for Design and Operation of Hydraulic Structures and Systems for Nuclear Power Plants (Rev. 1, October 1978)	2.4
1.126	An Acceptable Model and Related Statistical Methods for the Analysis of Fuel Densification (Rev. 1, March 1978)	4.2
1.127	Inspection of Water-Control Structures Associated With Nuclear Power Plants (Rev. 1, March 1978)	This regulatory guide is not applicable to AP1000.
1.128	Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants (Rev. 1, October 1978)	8.3.2
1.129	Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Nuclear Power Plants (Rev. 1, February 1978)	This regulatory guide is not applicable to AP1000 design certification.
1.130	Service Limits and Loading Combinations for Class 1 Plate-and-Shell-Type Component Supports (Rev. 1, October 1978)	3.9.3
1.131	Qualification Tests of Electric Cables, Field Splices and Connections for Light-Water-Cooled Nuclear Power Plants (Rev. 0, August 1977)	3.11
1.132	Site Investigations for Foundations of Nuclear Power Plants (Rev. 1, March 1979)	This regulatory guide is not applicable to AP1000 design certification.
1.133	Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors (Rev. 1, May 1981)	4.4.6.4

Table 1.9-1 (Sheet 11 of 15)

REGULATORY GUIDE/DCD SECTION CROSS-REFERENCES

Division 1 Regulatory Guide		DCD Chapter, Section or Subsection
1.134	Medical Evaluation of Nuclear Power Plant Personnel Requiring Operator Licenses (Rev. 3, March 1998)	This regulatory guide is not applicable to AP1000 design certification.
1.135	Normal Water Level and Discharge at Nuclear Power Plants (Rev. 0, September 1977)	2.4
1.136	Material for Concrete Containments (Rev. 2, June 1981)	This regulatory guide is not applicable to AP1000.
1.137	Fuel-Oil Systems for Standby Diesel Generators (Rev. 1, October 1979)	9.5.4
1.138	Laboratory Investigation of Soils for Engineering Analysis and Design of Nuclear Power Plants (Rev. 0, April 1978)	This regulatory guide is not applicable to AP1000 design certification.
1.139	Guidance for Residual Heat Removal (Rev. 0, May 1978)	6.3 7.4
1.140	Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Normal Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants (Rev. 2, June 2001)	9.4.1 9.4.4 9.4.5 9.4.7 9.4.9
1.141	Containment Isolation Provisions for Fluid Systems (Rev. 0, April 1978)	6.2.4
1.142	Safety-Related Concrete Structures for Nuclear Power Plants (Other Than Reactor Vessels and Containments) (Rev. 1, October 1981)	3.8.3 3.8.4 3.8.5
1.143	Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants (Rev. 1, October 1979)	3.8.4 10.4.8 11.2 11.3 11.4 11.5
1.144	Withdrawn	
1.145	Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants (Rev. 1, November 1982)	This regulatory guide is not applicable to AP1000 design certification.
1.146	Withdrawn	
1.147	Inservice Inspection Code Case Acceptability ASME Section XI Division 1 (Rev. 12, May 1999)	This regulatory guide is not applicable to AP1000 design certification.

Table 1.9-1 (Sheet 12 of 15)

REGULATORY GUIDE/DCD SECTION CROSS-REFERENCES

Division 1 Regulatory Guide		DCD Chapter, Section or Subsection
1.148	Functional Specification for Active Valve Assemblies in Systems Important to Safety in Nuclear Power Plants (Rev. 0, March 1981)	3.10 5.4.8
1.149	Nuclear Power Plant Simulation Facilities for Use in Operator License Examinations (Rev. 2, April 1996)	This regulatory guide is not applicable to AP1000 design certification.
1.150	Ultrasonic Testing of Reactor Pressure Vessel Welds During Preservice and Inservice Examinations (Rev. 1, February 1983)	5.2.4 5.3.2 5.3.4
1.151	Instrument Sensing Lines (Task 1C 126-5) (Rev. 0, July 1983)	7.1 7.5 7.6 7.7
1.152	Criteria for Programmable Digital Computer System Software in Safety-Related Systems of Nuclear Power Plants (Task 1C 127-5) (Rev. 1, January 1996)	7.1 7.2 7.3 7.4 7.5 7.6
1.153	Criteria for Power, Instrumentation, and Control Portions of Safety Systems (Task 1C 609-5) (Rev. 1, June 1996)	7.1 7.2 7.3 7.4 7.5 7.6
1.154	Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors (Rev. 0, January 1987)	5.3
1.155	Station Blackout (Task SI 501-4) (Rev. 0, August 1988)	8.2 8.3.1
1.156	Environmental Qualification of Connection Assemblies for Nuclear Power Plants (Task EE 404-4) (Rev. 0, November 1987)	3.10 3.11
1.157	Best-Estimate Calculations of Emergency Core Cooling System Performance (Task RS 701-4) (Rev. 0, May 1989)	6.3
1.158	Qualification of Safety-Related Lead Storage Batteries for Nuclear Power Plants (Task EE 006-5) (Rev. 0, February 1989)	3.10 3.11

Table 1.9-1 (Sheet 13 of 15)

REGULATORY GUIDE/DCD SECTION CROSS-REFERENCES

Division 1 Regulatory Guide		DCD Chapter, Section or Subsection
1.159	Assuring the Availability of Funds for Decommissioning Nuclear Reactors (Rev. 0, August 1990)	This regulatory guide is not applicable to AP1000 design certification.
1.160	Monitoring the Effectiveness of Maintenance at Nuclear Power Plants (Rev. 2, March 1997)	This regulatory guide is not applicable to AP1000 design certification.
1.161	Evaluation of Reactor Pressure Vessels with Charpy Upper-Shelf Energy Less Than 50 Ft-Lb (Rev. 0, June 1995)	This regulatory guide is not applicable to AP1000 design certification.
1.162	Format and Content of Report for Thermal Annealing of Reactor Pressure Vessels (Rev. 0, February 1996)	This regulatory guide is not applicable to AP1000 design certification.
1.163	Performance Based Containment Leak-Test Program (Rev. 0, September 1995)	6.2
1.165	Identification and Characterization of Seismic Sources and Determination Safe Shutdown Earthquake Ground Motion (Rev. 0, March 1997)	
1.166	Pre-Earthquake Planning and Immediate Nuclear Power Plant Operator Postearthquake Actions (Rev. 0, March 1997)	This regulatory guide is not applicable to AP1000 design certification.
1.167	Restart of a Nuclear Power Plant Shut Down by a Seismic Event (Rev. 0, March 1997)	This regulatory guide is not applicable to AP1000 design certification.
1.168	Verification, Validation, Reviews, and Audits for Digital Computer Software Used in Safety Systems of Nuclear Power Plants (Rev. 0, September 1997)	This regulatory guide is not applicable to AP1000 design certification.
1.169	Configuration Management Plans for Digital Computer Software Used in Safety Systems of Nuclear Power Plants (Rev. 0, September 1997)	This regulatory guide is not applicable to AP1000 design certification.
1.170	Software Test Documentation for Digital Computer Software Used in Safety Systems of Nuclear Power Plants (Rev. 0, September 1997)	This regulatory guide is not applicable to AP1000 design certification.
1.171	Software Unit Testing for Digital Computer Software Used in Safety Systems of Nuclear Power Plants (Rev. 0, September 1997)	This regulatory guide is not applicable to AP1000 design certification.

Table 1.9-1 (Sheet 14 of 15)

REGULATORY GUIDE/DCD SECTION CROSS-REFERENCES

Division 1 Regulatory Guide		**DCD Chapter, Section or Subsection**
1.172	Software Requirements Specifications for Digital Computer Software Used in Safety Systems of Nuclear Power Plants (Rev. 0, September 1997)	This regulatory guide is not applicable to AP1000 design certification.
1.173	Developing Software Life Cycle Processes for Digital Computer Software Used in Safety Systems of Nuclear Power Plants (Rev. 0, September 1997)	This regulatory guide is not applicable to AP1000 design certification.
1.174	An Approach for using Probabilistic Risk Assessment in Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis (Rev. 0, July 1998)	This regulatory guide is not applicable to AP1000 design certification.
1.175	An Approach for Plant-Specific, Risk-Informed Decisionmaking: Inservice Testing (Rev. 0, July 1998)	This regulatory guide is not applicable to AP1000 design certification.
1.176	An Approach for Plant-Specific, Risk-Informed Decisionmaking: Graded Quality Assurance (Rev. 0, August 1998)	This regulatory guide is not applicable to AP1000 design certification.
1.177	An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications (Rev. 0, August 1998)	This regulatory guide is not applicable to AP1000 design certification.
1.178	An Approach for Plant-Specific, Risk-Informed Decisionmaking: Inservice Inspection of Piping (Rev. 0, September 1998)	This regulatory guide is not applicable to AP1000 design certification.
1.179	Standard Format and Content of License Termination Plans for Nuclear Power Reactors (Rev. 0, January 1999)	This regulatory guide is not applicable to AP1000 design certification.
1.180	Guidelines for Evaluating Electromagnetic and Radio-Frequency Interference in Safety-Related Instrumentation and Control Systems (Rev. 0, January 2000)	This regulatory guide is not applicable to AP1000 design certification.
1.181	Content of the Updated Final Safety Analysis Report in Accordance with 10 CFR 50.71(e) (Rev. 0, September 1999)	This regulatory guide is not applicable to AP1000 design certification.
1.182	Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants (Rev. 0, May 2000)	This regulatory guide is not applicable to AP1000 design certification.

Table 1.9-1 (Sheet 15 of 15)

REGULATORY GUIDE/DCD SECTION CROSS-REFERENCES

Division 1 Regulatory Guide		**DCD Chapter, Section or Subsection**
1.183	Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors (Rev. 0, July 2000)	2.3 4.2 6.5.1 15.4 15.6.3 15.7
1.184	Decommissioning of Nuclear Power Reactors (Rev. 0, August 2000)	This regulatory guide is not applicable to AP1000 design certification.
1.185	Standard Format and Content for Post-shutdown Decommissioning Activities Report (Rev. 0, August 2000)	This regulatory guide is not applicable to AP1000 design certification.
1.186	Guidance and Examples of Identifying 10 CFR 50.2 Design Bases (Rev. 0, December 2000)	This regulatory guide is not applicable to AP1000 design certification.
1.187	Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments (Rev. 0, November 2000)	This regulatory guide is not applicable to AP1000 design certification.
1.189	Fire Protection for Operating Nuclear Power Plants (Rev. 0, April 2001)	This regulatory guide is not applicable to AP1000 design certification.
1.190	Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence (Rev. 0, March 2001)	5.3.2.6.2.2

Table 1.9-2 (Sheet 1 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
TMI Action Plan Items			
I.A.1.1	Shift Technical Advisor	f	
I.A.1.2	Shift Supervisor Administrative Duties	f	
I.A.1.3	Shift Manning	f	
I.A.1.4	Long-Term Upgrading	f	See DCD subsection 13.1.1
I.A.2.1(1)	Qualifications - Experience	f	
I.A.2.1(2)	Training	f	
I.A.2.1(3)	Facility Certification of Competence and Fitness of Applicants for Operator and Senior Operator Licenses	f	
I.A.2.2	Training and Qualifications of Operations Personnel	c	
I.A.2.3	Administration of Training Programs	f	
I.A.2.4	NRR Participation in Inspector Training	d	
I.A.2.5	Plant Drills	c	
I.A.2.6(1)	Revise Regulatory Guide 1.8	f	
I.A.2.6(2)	Staff Review of NRR 80-117	c	
I.A.2.6(3)	Revise 10 CFR 55	e	
I.A.2.6(4)	Operator Workshops	c	
I.A.2.6(5)	Develop Inspection Procedures for Training Programs	c	
I.A.2.6(6)	Nuclear Power Fundamentals	a	
I.A.2.7	Accreditation of Training Institutions	c	
I.A.3.1	Revise Scope of Criteria for Licensing Examinations	f	
I.A.3.2	Operator Licensing Program Changes	c	
I.A.3.3	Requirements for Operator Fitness	c	
I.A.3.4	Licensing of Additional Operations Personnel	c	
I.A.3.5	Establish Statement of Understanding with INPO and DOE	d	

Table 1.9-2 (Sheet 2 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
I.A.4.1(1)	Short-Term Study of Training Simulators	c	
I.A.4.1(2)	Interim Changes in Training Simulators	f	
I.A.4.2(1)	Research on Training Simulators	f	
I.A.4.2(2)	Upgrade Training Simulator Standards	f	
I.A.4.2(3)	Regulatory Guide on Training Simulators	f	See DCD subsection 1.9.3, item (2)(i)
I.A.4.2(4)	Review Simulators for Conformance to Criteria	f	
I.A.4.3	Feasibility Study of Procurement of NRC Training Simulator	d	
I.A.4.4	Feasibility Study of NRC Engineering Computer	d	
I.B.1.1(1)	Prepare Draft Criteria	c	
I.B.1.1(2)	Prepare Commission Paper	c	
I.B.1.1(3)	Issue Requirements for the Upgrading of Management and Technical Resources	c	
I.B.1.1(4)	Review Responses to Determine Acceptability	c	
I.B.1.1(5)	Review Implementation of the Upgrading Activities	c	
I.B.1.1(6)	Prepare Revisions to Regulatory Guides 1.33 and 1.8	e	
I.B.1.1(7)	Issue Regulatory Guides 1.33 and 1.8	e	
I.B.1.2(1)	Prepare Draft Criteria	c	
I.B.1.2(2)	Review Near-Term Operating License Facilities	c	
I.B.1.2(3)	Include Findings in the SER for Each Near-Term Operating License Facility	c	
I.B.1.3(1)	Require Licensees to Place Plant in Safest Shutdown Cooling Following a Loss of Safety Function Due to Personnel Error	d	
I.B.1.3(2)	Use Existing Enforcement Options to Accomplish Safest Shutdown Cooling	d	
I.B.1.3(3)	Use Non-Fiscal Approaches to Accomplish Safest Shutdown Cooling	d	
I.B.2.1(1)	Verify the Adequacy of Management and Procedural Controls and Staff Discipline	d	

Table 1.9-2 (Sheet 3 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
I.B.2.1(2)	Verify that Systems Required to Be Operable Are Properly Aligned	d	
I.B.2.1(3)	Follow-up on Completed Maintenance Work Orders to Ensure Proper Testing and Return to Service	d	
I.B.2.1(4)	Observe Surveillance Tests to Determine Whether Test Instruments Are Properly Calibrated	d	
I.B.2.1(5)	Verify that Licensees Are Complying with Technical Specifications	d	
I.B.2.1(6)	Observe Routine Maintenance	d	
I.B.2.1(7)	Inspect Terminal Boards, Panels, and Instrument Racks for Unauthorized Jumpers and Bypasses	d	
I.B.2.2	Resident Inspector at Operating Reactors	d	
I.B.2.3	Regional Evaluations	d	
I.B.2.4	Overview of Licensee Performance	d	
I.C.1(1)	Small Break LOCAs	f	
I.C.1(2)	Inadequate Core Cooling	f	
I.C.1(3)	Transients and Accidents	f	
I.C.1(4)	Confirmatory Analyses of Selected Transients	c	
I.C.2	Shift and Relief Turnover Procedures	f	
I.C.3	Shift Supervisor Responsibilities	f	
I.C.4	Control Room Access	f	
I.C.5	Procedures for Feedback of Operating Experience to Plant Staff	g	See DCD subsection 1.9.3, item (3)(i)
I.C.6	Procedures for Verification of Correct Performance of Operating Activities	f	
I.C.7	NSSS Vendor Review of Procedures	f	
I.C.8	Pilot Monitoring of Selected Emergency Procedures for Near-Term Operating License Applicants	f	

Table 1.9-2 (Sheet 4 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
I.C.9	Long-Term Program Plan for Upgrading of Procedures	c	See DCD subsections 13.5.1 and 1.9.3, item (2)(ii)
I.D.1	Control Room Design Reviews	g	See DCD subsection 1.9.3, item (2)(iii)
I.D.2	Plant Safety Parameter Display Console	g	See DCD subsection 1.9.3, item (2)(iv)
I.D.3	Safety System Status Monitoring	c	See DCD subsection 1.9.3, item (2)(v)
I.D.4	Control Room Design Standard	c	
I.D.5(1)	Operator-Process Communication	c	
I.D.5(2)	Plant Status and Post-Accident Monitoring	g	See DCD subsection 1.9.4, item I.D.5(2)
I.D.5(3)	On-Line Reactor Surveillance System	c	See DCD subsection 1.9.4, item I.D.5(3)
I.D.5(4)	Process Monitoring Instrumentation	c	
I.D.5(5)	Disturbance Analysis Systems	d	
I.D.6	Technology Transfer Conference	d	
I.E.1	Office for Analysis and Evaluation of Operational Data	d	
I.E.2	Program Office Operational Data Evaluation	d	
I.E.3	Operational Safety Data Analysis	d	
I.E.4	Coordination of Licensee, Industry, and Regulatory Programs	d	
I.E.5	Nuclear Plant Reliability Data Systems	d	
I.E.6	Reporting Requirements	d	
I.E.7	Foreign Sources	d	
I.E.8	Human Error Rate Analysis	d	
I.F.1	Expand QA List	c, j	See DCD subsections 1.9.4.2.1, item I.F.1 and 1.9.3, item (3)(ii)

Table 1.9-2 (Sheet 5 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
I.F.2(1)	Assure the Independence of the Organization Performing the Checking Function	a	See DCD subsection 17.5
I.F.2(2)	Include QA Personnel in Review and Approval of Plant Procedures	g	See DCD subsection 1.9.3, item (3)(iii)
I.F.2(3)	Include QA Personnel in All Design, Construction, Installation, Testing, and Operation Activities	g	See DCD subsection 1.9.3, item (3)(iii)
I.F.2(4)	Establish Criteria for Determining QA Requirements for Specific Classes of Equipment	a	See DCD subsection 17.5
I.F.2(5)	Establish Qualification Requirements for QA and QC Personnel	a	See DCD subsection 17.5
I.F.2(6)	Increase the Size of Licensees' QA Staff	f	
I.F.2(7)	Clarify that the QA Program Is a Condition of the Construction Permit and Operating License	a	See DCD subsection 17.5
I.F.2(8)	Compare NRC QA Requirements with Those of Other Agencies	a	See DCD subsection 17.5
I.F.2(9)	Clarify Organizational Reporting Levels for the QA Organization	f	
I.F.2(10)	Clarify Requirements for Maintenance of "As-Built" Documentation	a	See DCD subsection 17.5
I.F.2(11)	Define Role of QA in Design and Analysis Activities	a	See DCD subsection 17.5
I.G.1	Training Requirements	f, j	See DCD subsection 1.9.4.2.1, item I.G.1
I.G.2	Scope of Test Program	f, j	See DCD subsection 1.9.4.2.1, item I.G.2
II.A.1	Siting Policy Reformulation	c	
II.A.2	Site Evaluation of Existing Facilities	e	
II.B.1	Reactor Coolant System Vents	g	See DCD subsection 1.9.3, item (2)(vi)
II.B.2	Plant Shielding to Provide Access to Vital Areas and Protect Safety Equipment for Post-Accident Operation	g	See DCD subsection 1.9.3, item (2)(vii)

Table 1.9-2 (Sheet 6 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
II.B.3	Post-Accident Sampling	g	See DCD subsection 1.9.3, item (2)(viii)
II.B.4	Training for Mitigating Core Damage	f	
II.B.5(1)	Behavior of Severely Damages Fuel	d	
II.B.5(2)	Behavior of Core Melt	d	
II.B.5(3)	Effect of Hydrogen Burning and Explosions on Containment Structures	d	
II.B.6	Risk Reduction for Operating Reactors at Sites with High Population Densities	f	
II.B.7	Analysis of Hydrogen Control	e	
II.B.8	Rulemaking Proceedings on Degraded Core Accidents	g	See DCD subsection 1.9.3, items (1)(i), (1)(xii), (2)(ix), (3)(iv), and (3)(v)
II.C.1	Interim Reliability Evaluation Program	c	
II.C.2	Continuation of Interim Reliability Evaluation Program	c	
II.C.3	Systems Interaction	e	
II.C.4	Reliability Engineering	c	
II.D.1	Testing Requirements	g	See DCD subsection 1.9.3, item (2)(x)
II.D.2	Research on Relief and Safety Valve Test Requirements	a	
II.D.3	Relief and Safety Valve Position Indication	g	See DCD subsection 1.9.3, item (2)(xi)
II.E.1.1	Auxiliary Feedwater System Evaluation	g	See DCD subsection 1.9.3, item (1)(ii)
II.E.1.2	Auxiliary Feedwater System Automatic Initiation and Flow Indication	g	See DCD subsection 1.9.3, items (1)(ii) and (2)(xii)
II.E.1.3	Update Standard Review Plan and Develop Regulatory Guide	d, j	See DCD subsection 1.9.4.2.1, item II.E.1.3

Table 1.9-2 (Sheet 7 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
II.E.2.1	Reliance on ECCS	e	
II.E.2.2	Research on Small Break LOCAs and Anomalous Transients	c	
II.E.2.3	Uncertainties in Performance Predictions	a	
II.E.3.1	Reliability of Power Supplies for Natural Circulation	g	See DCD subsection 1.9.3, item (2)(xiii)
II.E.3.2	Systems Reliability	e	
II.E.3.3	Coordinated Study of Shutdown Heat Removal Requirements	e	
II.E.3.4	Alternate Concepts Research	c	
II.E.3.5	Regulatory Guide	e	
II.E.4.1	Dedicated Penetrations	g	See DCD subsection 1.9.3, item (3)(vi)
II.E.4.2	Isolation Dependability	g	See DCD subsection 1.9.3, item (2)(xiv)
II.E.4.3	Integrity Check	c	
II.E.4.4	Purging	g	See DCD subsection 1.9.3, item (2)(xv)
II.E.5.1	Design Evaluation	b	
II.E.5.2	B&W Reactor Transient Response Task Force	b	
II.E.6.1	Test Adequacy Study	d, j	See DCD subsection 1.9.4.2.1, item II.E.6.1
II.F.1	Additional Accident Monitoring Instrumentation	g	See DCD subsection 1.9.3, item (2)(xvii)
II.F.2	Identification of and Recovery from Conditions Leading to Inadequate Core Cooling	g	See DCD subsection 1.9.3, item (2)(xviii)
II.F.3	Instruments for Monitoring Accident Conditions	g	See DCD subsection 1.9.3, item (2)(xix)
II.F.4	Study of Control and Protective Action Design Requirements	a	

Table 1.9-2 (Sheet 8 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
II.F.5	Classification of Instrumentation, Control, and Electrical Equipment	d	
II.G.1	Power Supplies for Pressurizer Relief Valves, Block Valves, and Level Indicators	g	See DCD subsection 1.9.3, item (2)(xx)
II.H.1	Maintain Safety of TMI-2 and Minimize Environmental Impact	c	
II.H.2	Obtain Technical Data on the Conditions Inside the TMI-2 Containment Structure	b	
II.H.3	Evaluate and Feed Back Information Obtained from TMI	e	
II.H.4	Determine Impact of TMI on Socioeconomic and Real Property Values	d	
II.J.1.1	Establish a Priority System for Conducting Vendor Inspections	d	
II.J.1.2	Modify Existing Vendor Inspection Program	d	
II.J.1.3	Increase Regulatory Control Over Present Non-Licensees	d	
II.J.1.4	Assign Resident Inspectors to Reactor Vendors and Architect-Engineers	d	
II.J.2.1	Reorient Construction Inspection Program	d	
II.J.2.2	Increase Emphasis on Independent Measurement in Construction Inspection Program	d	
II.J.2.3	Assign Resident Inspectors to All Construction Sites	d	
II.J.3.1	Organization and Staffing to Oversee Design and Construction	f	See DCD subsection 1.9.3, item (3)(vii)
II.J.3.2	Issue Regulatory Guide	e	
II.J.4.1	Revise Deficiency Reporting Requirements	f	
II.K.1(1)	Review TMI-2 PNs and Detailed Chronology of the TMI-2 Accident	f	
II.K.1(2)	Review Transients Similar to TMI-2 That Have Occurred at Other Facilities and NRC Evaluation of Davis-Besse Event	b	
II.K.1(3)	Review Operating Procedures for Recognizing, Preventing, and Mitigating Void Formation in Transients and Accidents	f	

Table 1.9-2 (Sheet 9 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
II.K.1(4)	Review Operating Procedures and Training Instructions	f	
II.K.1(5)	Safety-Related Valve Position Description	f	
II.K.1(6)	Review Containment Isolation Initiation Design and Procedures	f	
II.K.1(7)	Implement Positive Position Controls on Valves That Could Compromise or Defeat AFW Flow	b	
II.K.1(8)	Implement Procedures That Assure Two Independent 100% AFW Flow Paths	b	
II.K.1(9)	Review Procedures to Assure That Radioactive Liquids and Gases Are Not Transferred out of Containment Inadvertently	f	
II.K.1(10)	Review and Modify Procedures for Removing Safety-Related Systems from Service	f, j	See DCD subsection 1.9.4.2.1, item II.K.1(10)
II.K.1(11)	Make All Operating and Maintenance Personnel Aware of the Seriousness and Consequences of the Erroneous Actions Leading up to, and in Early Phases of, the TMI-2 Accident	f	
II.K.1(12)	One Hour Notification Requirement and Continuous Communications Channels	f	
II.K.1(13)	Propose Technical Specification Changes Reflecting Implementation of All Bulletin Items	f, j	See DCD subsection 1.9.4.2.1, item II.K.1(13)
II.K.1(14)	Review Operating Modes and Procedures to Deal with Significant Amounts of Hydrogen	f	
II.K.1(15)	For Facilities with Non-Automatic AFW Initiation, Provide Dedicated Operator in Continuous Communication with CR to Operate AFW	f	
II.K.1(16)	Implement Procedures That Identify PZR PORV "Open" Indications and That Direct Operator to Close Manually at "Reset" Setpoint	f	
II.K.1(17)	Trip PZR Level Bistable so That PZR Low Pressure Will Initiate Safety Injection	f, j	See DCD subsection 1.9.4.2.1, item II.K.1(17)

Table 1.9-2 (Sheet 10 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
II.K.1(18)	Develop Procedures and Train Operators on Methods of Establishing and Maintaining Natural Circulation	b	
II.K.1(19)	Describe Design and Procedure Modifications to Reduce Likelihood of Automatic PZR PORV Actuation in Transients	b	
II.K.1(20)	Provide Procedures and Training to Operators for Prompt Manual Reactor Trip for LOFW, TT, MSIV Closure, LOOP, LOSG Level, and LO PZR Level	b	
II.K.1(21)	Provide Automatic Safety-Grade Anticipatory Reactor Trip for LOFW, TT, or Significant Decrease in SG Level	b	
II.K.1(22)	Describe Automatic and Manual Actions for Proper Functioning of Auxiliary Heat Removal Systems When FW System Not Operable	g	See DCD subsection 1.9.3, item (2)(xxi)
II.K.1(23)	Describe Uses and Types of RV Level Indication for Automatic and Manual Initiation Safety Systems	b	
II.K.1(24)	Perform LOCA Analyses for a Range of Small-Break Sizes and a Range of Time Lapses Between Reactor Trip and RCP Trip	e, j	See DCD subsection 1.9.4.2.1, item II.K.1(24)
II.K.1(25)	Develop Operator Action Guidelines	e	
II.K.1(26)	Revise Emergency Procedures and Train ROs and SROs	f	
II.K.1(27)	Provide Analyses and Develop Guidelines and Procedures for Inadequate Core Cooling Conditions	e	
II.K.1(28)	Provide Design That Will Assure Automatic RCP Trip for All Circumstances Where Required	e	
II.K.2(1)	Upgrade Timeliness and Reliability of AFW System	b	
II.K.2(2)	Procedures and Training to Initiate and Control AFW Independent of Integrated Control System	b	
II.K.2(3)	Hard-Wired Control-Grade Anticipatory Reactor Trips	b	
II.K.2(4)	Small-Break LOCA Analysis, Procedures and Operator Training	b	
II.K.2(5)	Complete TMI-2 Simulator Training for All Operators	b	
II.K.2(6)	Reevaluate Analysis of Dual-Level Setpoint Control	b	

Table 1.9-2 (Sheet 11 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
II.K.2(7)	Reevaluate Transient of September 24, 1977	b	
II.K.2(8)	Continued Upgrading of AFW System	e	
II.K.2(9)	Analysis and Upgrading of Integrated Control System	e	
II.K.2(10)	Hard-Wired Safety-Grade Anticipatory Reactor Trips	b	See DCD subsection 1.9.3, item (2)(xxiii)
II.K.2(11)	Operator Training and Drilling	b	
II.K.2(12)	Transient Analysis and Procedures for Management of Small Breaks	e	
II.K.2(13)	Thermal-Mechanical Report on Effect of HPI on Vessel Integrity for Small-Break LOCA With No AFW	b	
II.K.2(14)	Demonstrate That Predicted Lift Frequency of PORVs and SVs Is Acceptable	b	
II.K.2(15)	Analysis of Effects of Slug Flow on Once-Through Steam Generator Tubes After Primary System Voiding	b	
II.K.2(16)	Impact of RCP Seal Damage Following Small-Break LOCA With Loss of Offsite Power	g	See DCD subsection 1.9.3, item (1)(iii)
II.K.2(17)	Analysis of Potential Voiding in RCS During Anticipated Transients	b	
II.K.2(18)	Analysis of Loss of Feedwater and Other Anticipated Transients	e	
II.K.2(19)	Benchmark Analysis of Sequential AFW Flow to Once-Through Steam Generator	b	
II.K.2(20)	Analysis of Steam Response to Small-Break LOCA	b	
II.K.2(21)	LOFT L3-1 Predictions	b	
II.K.3(1)	Install Automatic PORV Isolation System and Perform Operational Test	g	See DCD subsection 1.9.3, item (1)(iv)
II.K.3(2)	Report on Overall Safety Effect of PORV Isolation System	g	See DCD subsection 1.9.3, item (1)(iv)
II.K.3(3)	Report Safety and Relief Valve Failures Promptly and Challenges Annually	f	

Table 1.9-2 (Sheet 12 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
II.K.3(4)	Review and Upgrade Reliability and Redundancy of Non-Safety Equipment for Small-Break LOCA Mitigation	e	
II.K.3(5)	Automatic Trip of Reactor Coolant Pumps	f, j	See DCD subsection 1.9.4.2.1, item II.K.3(5)
II.K.3(6)	Instrumentation to Verify Natural Circulation	e	
II.K.3(7)	Evaluation of PORV Opening Probability During Overpressure Transient	b	
II.K.3(8)	Further Staff Consideration of Need for Diverse Decay Heat Removal Method Independent of SGs	e	
II.K.3(9)	Proportional Integral Derivative Controller Modification	g	See DCD subsection 1.9.4, item II.K.3(9)
II.K.3(10)	Anticipatory Trip Modification Proposed by Some Licensees to Confine Range of Use to High Power Levels	f	
II.K.3(11)	Control Use of PORV Supplied by Control Components, Inc. Until Further Review Complete	f	
II.K.3(12)	Confirm Existence of Anticipatory Trip Upon Turbine Trip	f	
II.K.3(13)	Separation of HPCI and RCIC System Initiation Levels	b	
II.K.3(14)	Isolation of Isolation Condensers on High Radiation	b	
II.K.3(15)	Modify Break Detection Logic to Prevent Spurious Isolation of HPCI and RCIC Systems	b	
II.K.3(16)	Reduction of Challenges and Failures of Relief Valves - Feasibility Study and System Modification	b	
II.K.3(17)	Report on Outage of ECC Systems - Licensee Report and Technical Specification Changes	b	
II.K.3(18)	Modification of ADS Logic - Feasibility Study and Modification for Increased Diversity for Some Event Sequences	g	See DCD subsection 1.9.3, item (1)(vii)
II.K.3(19)	Interlock on Recirculation Pump Loops	b	
II.K.3(20)	Loss of Service Water for Big Rock Point	b	

Table 1.9-2 (Sheet 13 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
II.K.3(21)	Restart of Core Spray and LPCI Systems on Low Level - Design and Modification	b	
II.K.3(22)	Automatic Switchover of RCIC System Suction - Verify Procedures and Modify Design	b	
II.K.3(23)	Central Water Level Recording	e	
II.K.3(24)	Confirm Adequacy of Space Cooling for HPCI and RCIC Systems	b	
II.K.3(25)	Effect of Loss of AC Power on Pump Seals	g	See DCD subsection 1.9.3, item (1)(iii)
II.K.3(26)	Study Effect on RHR Reliability of Its Use for Fuel Pool Cooling	e	
II.K.3(27)	Provide Common Reference Level for Vessel Level Instrumentation	b	
II.K.3(28)	Study and Verify Qualification of Accumulators on ADS Valves	g	See DCD subsection 1.9.3, item (1)(x)
II.K.3(29)	Study to Demonstrate Performance of Isolation Condensers with Non-Condensibles	b	
II.K.3(30)	Revised Small-Break LOCA Methods to Show Compliance with 10 CFR 50, Appendix K	f	
II.K.3(31)	Plant-Specific Calculations to Show Compliance with 10 CFR 50.46	f	
II.K.3(32)	Provide Experimental Verification of Two-Phase Natural Circulation Models	e	
II.K.3(33)	Evaluate Elimination of PORV Function	e	
II.K.3(34)	Relap-4 Model Development	e	
II.K.3(35)	Evaluation of Effects of Core Flood Tank Injection on Small-Break LOCAs	e	
II.K.3(36)	Additional Staff Audit Calculations of B&W Small-Break LOCA Analyses	e	
II.K.3(37)	Analysis of B&W Response to Isolated Small-Break LOCA	e	

Table 1.9-2 (Sheet 14 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
II.K.3(38)	Analysis of Plant Response to a Small-Break LOCA in the Pressurizer Spray Line	e	
II.K.3(39)	Evaluation of Effects of Water Slugs in Piping Caused by HPI and CFT Flows	e	
II.K.3(40)	Evaluation of RCP Seal Damage and Leakage During a Small-Break LOCA	e	
II.K.3(41)	Submit Predictions for LOFT Test L3-6 with RCPs Running	e	
II.K.3(42)	Submit Requested Information on the Effects of Non Condensible Gases	e	
II.K.3(43)	Evaluation of Mechanical Effects of Slug Flow on Steam Generator Tubes	e	
II.K.3(44)	Evaluation of Anticipated Transients with Single Failure to Verify No Significant Fuel Failure	b	
II.K.3(45)	Evaluate Depressurization with Other Than Full ADS	b	
II.K.3(46)	Response to List of Concerns from ACRS Consultant	b	
II.K.3(47)	Test Program for Small-Break LOCA Model Verification Pretest Prediction, Test Program, and Model Verification	e	
II.K.3(48)	Assess Change in Safety Reliability as a Result of Implementing B&OTF Recommendations	e	
II.K.3(49)	Review of Procedures (NRC)	e	
II.K.3(50)	Review of Procedures (NSSS Vendors)	e	
II.K.3(51)	Symptom-Based Emergency Procedures	e	
II.K.3(52)	Operator Awareness of Revised Emergency Procedures	e	
II.K.3(53)	Two Operators in Control Room	e	
II.K.3(54)	Simulator Upgrade for Small-Break LOCAs	e	
II.K.3(55)	Operator Monitoring of Control Board	e	
II.K.3(56)	Simulator Training Requirements	e	
II.K.3(57)	Identify Water Sources Prior to Manual Activation of ADS	b	

Table 1.9-2 (Sheet 15 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
III.A.1.1(1)	Implement Action Plan Requirements for Promptly Improving Licensee Emergency Preparedness	f	
III.A.1.1(2)	Perform an Integrated Assessment of the Implementation	f	
III.A.1.2	Upgrade Licensee Emergency Support Facilities	g	See DCD subsection 1.9.3, item (2)(xxv)
III.A.1.3(1)	Maintain Supplies of Thyroid-Blocking Agent - Workers	c	
III.A.1.3(2)	Maintain Supplies of Thyroid-Blocking Agent - Public	c	
III.A.2.1(1)	Publish Proposed Amendments to the Rules	d	
III.A.2.1(2)	Conduct Public Regional Meetings	d	
III.A.2.1(3)	Prepare Final Commission Paper Recommending Adoption of Rules	d	
III.A.2.1(4)	Revise Inspection Program to Cover Upgraded Requirements	d	
III.A.2.2	Development of Guidance and Criteria	d	
III.A.3.1(1)	Define NRC Role in Emergency Situations	c	
III.A.3.1(2)	Revise and Upgrade Plans and Procedures for the NRC Emergency Operations Center	c	
III.A.3.1(3)	Revise Manual Chapter 0502, Other Agency Procedures, and NUREG-0610	c	
III.A.3.1(4)	Prepare Commission Paper	c	
III.A.3.1(5)	Revise Implementing Procedures and Instructions for Regional Offices	c	
III.A.3.2	Improve Operations Centers	c	
III.A.3.3	Communications	d	See DCD subsection 9.5.2.5.2
III.A.3.4	Nuclear Data Link	c	
III.A.3.5	Training, Drills, and Tests	c	
III.A.3.6(1)	Interaction of NRC and Other Agencies - International	c	
III.A.3.6(2)	Federal	c	

Table 1.9-2 (Sheet 16 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
III.A.3.6(3)	State and Local	c	
III.B.1	Transfer of Responsibilities to FEMA	c	
III.B.2(1)	The Licensing Process	c	
III.B.2(2)	Federal Guidance	c	
III.C.1(1)	Review Publicly Available Documents	d	
III.C.1(2)	Recommend Publication of Additional Information	d	
III.C.1(3)	Program of Seminars for News Media Personnel	d	
III.C.2(1)	Develop Policy and Procedures for Dealing With Briefing Requests	d	
III.C.2(2)	Provide Training for Member of the Technical Staff	d	
III.D.1.1(1)	Review Information Submitted by Licensees Pertaining to Reducing Leakage from Operating Systems	g	See DCD subsection 1.9.3, item (2)(xxvi)
III.D.1.1(2)	Review Information on Provisions for Leak Detection	a	
III.D.1.1(3)	Develop Proposed System Acceptance Criteria	a	
III.D.1.2	Radioactive Gas Management	a	
III.D.1.3(1)	Decide Whether Licensees Should Perform Studies and Make Modifications	a	
III.D.1.3(2)	Review and Revise SRP	a	
III.D.1.3(3)	Require Licensees to Upgrade Filtration Systems	a	
III.D.1.3(4)	Sponsor Studies to Evaluate Charcoal Adsorber	c	
III.D.1.4	Radwaste System Design Features to Aid in Accident Recovery and Decontamination	a	
III.D.2.1(1)	Evaluate the Feasibility and Perform a Value-Impact Analysis of Modifying Effluent-Monitoring Design Criteria	a	
III.D.2.1(2)	Study the Feasibility of Requiring the Development of Effective Means for Monitoring and Sampling Noble Gases and Radioiodine Released to the Atmosphere	a	
III.D.2.1(3)	Revise Regulatory Guides	a	

Table 1.9-2 (Sheet 17 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
III.D.2.2(1)	Perform Study of Radioiodine, Carbon-14, and Tritium Behavior	c	
III.D.2.2(2)	Evaluate Data Collected at Quad Cities	e	
III.D.2.2(3)	Determine the Distribution of the Chemical Species of Radioiodine in Air-Water-Steam Mixtures	e	
III.D.2.2(4)	Revise SRP and Regulatory Guides	e	
III.D.2.3(1)	Develop Procedures to Discriminate Between Sites/Plants	c	
III.D.2.3(2)	Discriminate Between Sites and Plants That Require Consideration of Liquid Pathway Interdiction Techniques	c	
III.D.2.3(3)	Establish Feasible Method of Pathway Interdiction	c	
III.D.2.3(4)	Prepare a Summary Assessment	c	
III.D.2.4(1)	Study Feasibility of Environmental Monitors	c	
III.D.2.4(2)	Place 50 TLDs Around Each Site	d	
III.D.2.5	Offsite Dose Calculation Manual	c	
III.D.2.6	Independent Radiological Measurements	d	
III.D.3.1	Radiation Protection Plans	c	
III.D.3.2(1)	Amend 10 CFR 20	d	
III.D.3.2(2)	Issue a Regulatory Guide	d	
III.D.3.2(3)	Develop Standard Performance Criteria	d	
III.D.3.2(4)	Develop Method for Testing and Certifying Air-Purifying Respirators	d	
III.D.3.3	In-plant Radiation Monitoring	g	See DCD subsection 1.9.3, item (2)(xxvii)
III.D.3.4	Control Room Habitability	g	See DCD subsection 1.9.3, item (2)(xxviii)
III.D.3.5(1)	Develop Format for Data To Be Collected by Utilities Regarding Total Radiation Exposure to Workers	d	

Table 1.9-2 (Sheet 18 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
III.D.3.5(2)	Investigate Methods of Obtaining Employee Health Data by Nonlegislative Means	d	
III.D.3.5(3)	Revise 10 CFR 20	d	
IV.A.1	Seek Legislative Authority	d	
IV.A.2	Revise Enforcement Policy	d	
IV.B.1	Revise Practices for Issuance of Instructions and Information to Licensees	d	
IV.C.1	Extend Lessons Learned from TMI to Other NRC Programs	c	
IV.D.1	NRC Staff Training	d	
IV.E.1	Expand Research on Quantification of Safety Decision-Making	d	
IV.E.2	Plan for Early Resolution of Safety Issues	d	
IV.E.3	Plan for Resolving Issues at the CP Stage	d	
IV. E.4	Resolve Generic Issues by Rulemaking	d	
IV.E.5	Assess Currently Operating Reactors	c	
IV.F.1	Increased OIE Scrutiny of the Power-Ascension Test Program	c	
IV.F.2	Evaluate the Impacts of Financial Disincentives to the Safety of Nuclear Power Plants	c	
IV.G.1	Develop a Public Agenda for Rulemaking	d	
IV.G.2	Periodic and Systematic Reevaluation of Existing Rules	d	
IV.G.3	Improve Rulemaking Procedures	d	
IV.G.4	Study Alternatives for Improved Rulemaking Process	d	
IV.H.1	NRC Participation in the Radiation Policy Council	d	
V.A.1	Develop NRC Policy Statement on Safety	d	
V.B.1	Study and Recommend, as Appropriate, Elimination of Nonsafety Responsibilities	d	
V.C.1	Strengthen the Role of Advisory Committee on Reactor Safeguards	d	

Table 1.9-2 (Sheet 19 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
V.C.2	Study Need for Additional Advisory Committees	d	
V.C.3	Study the Need to Establish an Independent Nuclear Safety Board	d	
V.D.1	Improve Public and Intervenor Participation in the Hearing Process	d	
V.D.2	Study Construction-During-Adjudication Rules	d	
V.D.3	Reexamine Commission Role in Adjudication	d	
V.D.4	Study the Reform of the Licensing Process	d	
V.E.1	Study the Need for TMI-Related Legislation	d	
V.F.1	Study NRC Top Management Structure and Process	d	
V.F.2	Reexamine Organization and Functions of the NRC Offices	d	
V.F.3	Revise Delegations of Authority to Staff	d	
V.F.4	Clarify and Strengthen the Respective Roles of Chairman, Commission, and Executive Director for Operations	d	
V.F.5	Authority to Delegate Emergency Response Functions to a Single Commissioner	d	
V.G.1	Achieve Single Location, Long-Term	d	
V.G.2	Achieve Single Location, Interim	d	
Task Action Plan Items			
A-1	Water Hammer (former USI)	g	See DCD subsection 1.9.4, item A-1
A-2	Asymmetric Blowdown Loads on Reactor Primary Coolant Systems (former USI)	g	See DCD subsection 1.9.4, item A-2
A-3	Westinghouse Steam Generator Tube Integrity (former USI)	g	See DCD subsection 1.9.4, item A-3
A-4	CE Steam Generator Tube Integrity (former USI)	b	
A-5	B&W Steam Generator Tube Integrity (former USI)	b	
A-6	Mark I Short-Term Program (former USI)	b	

Table 1.9-2 (Sheet 20 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
A-7	Mark I Long-Term Program (former USI)	b	
A-8	Mark II Containment Pool Dynamic Loads Long-Term Program (former USI)	b	
A-9	ATWS (former USI)	g	See DCD subsection 1.9.4, item A-9
A-10	BWR Feedwater Nozzle Cracking (former USI)	b	
A-11	Reactor Vessel Materials Toughness (former USI)	g	See DCD subsection 1.9.4, item A-11
A-12	Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports (former USI)	g	See DCD subsection 1.9.4, item A-12
A-13	Snubber Operability Assurance	g	See DCD subsection 1.9.4, item A-13
A-14	Flaw Detection	a	
A-15	Primary Coolant System Decontamination and Steam Generator Chemical Cleaning	c	
A-16	Steam Effects on BWR Core Spray Distribution	b	
A-17	Systems Interactions in Nuclear Power Plants (former USI)	c, j	See DCD subsection 1.9.4.2.2, item A-17
A-18	Pipe Rupture Design Criteria	a	
A-19	Digital Computer Protection System	d	
A-20	Impacts of the Coal Fuel Cycle	d	
A-21	Main Steamline Break Inside Containment - Evaluation of Environmental Conditions for Equipment Qualification	a	
A-22	PWR Main Steamline Break - Core, Reactor Vessel and Containment Building Response	a	
A-23	Containment Leak Testing	d	
A-24	Qualification of Class e Safety-Related Equipment (former USI)	g	See DCD subsection 1.9.4, item A-24
A-25	Non-Safety Loads on Class e Power Sources	g	See DCD subsection 1.9.4, item A-25

Table 1.9-2 (Sheet 21 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
A-26	Reactor Vessel Pressure Transient Protection (former USI)	g	See DCD subsection 1.9.4, item A-26
A-27	Reload Applications	d	
A-28	Increase in Spent Fuel Pool Storage Capacity	g	See DCD subsection 1.9.4, item A-28
A-29	Nuclear Power Plant Design for the Reduction of Vulnerability to Industrial Sabotage	c, j	See DCD subsection 1.9.4.2.2, item A-29
A-30	Adequacy of Safety-Related DC Power Supplies	e	
A-31	RHR Shutdown Requirements (former USI)	g	See DCD subsection 1.9.4, item A-31
A-32	Missile Effects	e	
A-33	NEPA Review of Accident Risks	i	
A-34	Instruments for Monitoring Radiation and Process Variables During Accidents	e	
A-35	Adequacy of Offsite Power Systems	g	See DCD subsection 1.9.4, item A-35
A-36	Control of Heavy Loads Near Spent Fuel (former USI)	g	See DCD subsection 1.9.4, item A-36
A-37	Turbine Missiles	a	
A-38	Tornado Missiles	a	
A-39	Determination of Safety Relief Valve Pool Dynamic Loads and Temperature Limits (former USI)	b	See DCD subsection 1.9.4, item A-39
A-40	Seismic Design Criteria - Short Term Program (former USI)	g	See DCD subsection 1.9.4, item A-40
A-41	Long Term Seismic Program	c	
A-42	Pipe Cracks in Boiling Water Reactors (former USI)	b	
A-43	Containment Emergency Sump Performance (former USI)	g	See DCD subsection 1.9.4, item A-43
A-44	Station Blackout (former USI)	g	See DCD subsection 1.9.4, item A-44

Table 1.9-2 (Sheet 22 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
A-45	Shutdown Decay Heat Removal Requirements (former USI)	c	
A-46	Seismic Qualification of Equipment in Operating Plants (former USI)	g	See DCD subsection 1.9.4, item A-46
A-47	Safety Implications of Control Systems (former USI)	g	See DCD subsection 1.9.4, item A-47
A-48	Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment	g	See DCD subsection 1.9.4, item A-48
A-49	Pressurized Thermal Shock (former USI)	g	See DCD subsection 1.9.4, item A-49
B-1	Environmental Technical Specifications	d	
B-2	Forecasting Electricity Demand	d	
B-3	Event Categorization	a	
B-4	ECCS Reliability	e	
B-5	Ductility of Two-Way Slabs and Shells and Buckling Behavior of Steel Containments	c, j	See DCD subsection 1.9.4.2.2, item B-5
B-6	Loads, Load Combinations, Stress Limits	e	
B-7	Secondary Accident Consequence Modeling	a	
B-8	Locking Out of ECCS Power Operated Valves	a	
B-9	Electrical Cable Penetrations of Containment	c	
B-10	Behavior of BWR Mark III Containments	b	
B-11	Subcompartment Standard Problems	d	
B-12	Containment Cooling Requirements (Non-LOCA)	c	
B-13	Marviken Test Data Evaluation	d	
B-14	Study of Hydrogen Mixing Capability in Containment Post-LOCA	e	
B-15	CONTEMPT Computer Code Maintenance	a	
B-16	Protection Against Postulated Piping Failures in Fluid Systems Outside Containment	e	

Table 1.9-2 (Sheet 23 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
B-17	Criteria for Safety-Related Operator Actions	c	See DCD subsection 1.9.4, item B-17
B-18	Vortex Suppression Requirements for Containment Sumps	e	
B-19	Thermal-Hydraulic Stability	c	
B-20	Standard Problem Analysis	d	
B-21	Core Physics	a	
B-22	LWR Fuel	a	See DCD subsection 1.9.4, item B-22
B-23	LMFBR Fuel	a	
B-24	Seismic Qualification of Electrical and Mechanical Components	e	
B-25	Piping Benchmark Problems	d	
B-26	Structural Integrity of Containment Penetrations	c	
B-27	Implementation and Use of Subsection NF	d	
B-28	Radionuclide/Sediment Transport Program	d	
B-29	Effectiveness of Ultimate Heat Sinks	d	See DCD subsection 1.9.4, item B-29
B-30	Design Basis Floods and Probability	d	
B-31	Dam Failure Model	a	
B-32	Ice Effects on Safety-Related Water Supplies	e	See DCD subsection 1.9.4, item B-32
B-33	Dose Assessment Methodology	d	
B-34	Occupational Radiation Exposure Reduction	e	
B-35	Confirmation of Appendix I Models for Calculations of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light Water Cooled Power Reactors	d	

Table 1.9-2 (Sheet 24 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
B-36	Develop Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units for Engineered Safety Feature Systems and for Normal Ventilation Systems	g	See DCD subsection 1.9.4, item B-36
B-37	Chemical Discharges to Receiving Waters	d	
B-38	Reconnaissance Level Investigations	a	
B-39	Transmission Lines	a	
B-40	Effects of Power Plant Entrainment on Plankton	a	
B-41	Impacts on Fisheries	a	
B-42	Socioeconomic Environmental Impacts	d	
B-43	Value of Aerial Photographs for Site Evaluation	d	
B-44	Forecasts of Generating Costs of Coal and Nuclear Plants	d	
B-45	Need for Power - Energy Conservation	e	
B-46	Cost of Alternatives in Environmental Design	a	
B-47	Inservice Inspection of Supports - Classes 1, 2, 3, and MC Components	a	
B-48	BWR CRD Mechanical Failure (Collet Housing)	b	
B-49	Inservice Inspection Criteria and Corrosion Prevention Criteria for Containments	d	
B-50	Post-Operating Basis Earthquake Inspections	a	
B-51	Assessment of Inelastic Analysis Techniques for Equipment and Components	e	
B-52	Fuel Assembly Seismic and LOCA Responses	e	
B-53	Load Break Switch	g	See DCD subsection 1.9.4, item B-53
B-54	Ice Condenser Containments	c	
B-55	Improved Reliability of Target Rock Safety Relief Valves	b	
B-56	Diesel Reliability	g	See DCD subsection 1.9.4, item B-56

Table 1.9-2 (Sheet 25 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
B-57	Station Blackout	e	
B-58	Passive Mechanical Failures	c	
B-59	(N-1) Loop Operation in BWRs and PWRs	d	
B-60	Loose Parts Monitoring System	c	
B-61	Allowable ECCS Equipment Outage Periods	g	See DCD subsection 1.9.4, item B-61
B-62	Reexamination of Technical Bases for Establishing SLs, LSSSs, and Reactor Protection System Trip Functions	a	
B-63	Isolation of Low Pressure Systems Connected to the Reactor Coolant Pressure Boundary	g	See DCD subsection 1.9.4, item B-63
B-64	Decommissioning of Reactors	f	
B-65	Iodine Spiking	a	
B-66	Control Room Infiltration Measurements	g	See DCD subsection 1.9.4, item B-66
B-67	Effluent and Process Monitoring Instrumentation	e	
B-68	Pump Overspeed During LOCA	a	
B-69	ECCS Leakage Ex-Containment	e	
B-70	Power Grid Frequency Degradation and Effect on Primary Coolant Pumps	c	
B-71	Incident Response	e	
B-72	Health Effects and Life Shortening from Uranium and Coal Fuel Cycles	d	
B-73	Monitoring for Excessive Vibration Inside the Reactor Pressure Vessel	e	
C-1	Assurance of Continuous Long Term Capability of Hermetic Seals on Instrumentation and Electrical Equipment	g	See DCD subsection 1.9.4, item C-1
C-2	Study of Containment Depressurization by Inadvertent Spray Operation to Determine Adequacy of Containment External Design Pressure	c	

Table 1.9-2 (Sheet 26 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
C-3	Insulation Usage Within Containment	e	
C-4	Statistical Methods for ECCS Analysis	d	See DCD subsection 1.9.4, item C-4
C-5	Decay Heat Update	d	See DCD subsection 1.9.4, item C-5
C-6	LOCA Heat Sources	d	See DCD subsection 1.9.4, item C-6
C-7	PWR System Piping	c	
C-8	Main Steam Line Leakage Control Systems	b	
C-9	RHR Heat Exchanger Tube Failures	a	
C-10	Effective Operation of Containment Sprays in a LOCA	g	See DCD subsection 1.9.4, item C-10
C-11	Assessment of Failure and Reliability of Pumps and Valves	c	
C-12	Primary System Vibration Assessment	c	
C-13	Non-Random Failures	e	
C-14	Storm Surge Model for Coastal Sites	a	
C-15	NUREG Report for Liquids Tank Failure Analysis	a	
C-16	Assessment of Agricultural Land in Relation to Power Plant Siting and Cooling System Selection	a	
C-17	Interim Acceptance Criteria for Solidification Agents for Radioactive Solid Wastes	g	See DCD subsection 1.9.4, item C-17
D-1	Advisability of a Seismic Scram	a	
D-2	Emergency Core Cooling System Capability for Future Plants	a	
D-3	Control Rod Drop Accident	c	
New Generic Issues			
1.	Failures in Air-Monitoring, Air-Cleaning, and Ventilating Systems	a	
2.	Failure of Protective Devices on Essential Equipment	a	

Table 1.9-2 (Sheet 27 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
3.	Set Point Drift in Instrumentation	c	
4.	End-of-Life and Maintenance Criteria	c	
5.	Design Check and Audit of Balance-of-Plant Equipment	e	
6.	Separation of Control Rod from Its Drive and BWR High Rod Worth Events	c	
7.	Failures Due to Flow-Induced Vibrations	a	
8.	Inadvertent Actuation of Safety Injection in PWRs	e	
9.	Reevaluation of Reactor Coolant Pump Trip Criteria	e	
10.	Surveillance and Maintenance of TIP Isolation Valves and Squib Charges	a	
11.	Turbine Disc Cracking	e	
12.	BWR Jet Pump Integrity	b	
13.	Small Break LOCA from Extended Overheating of Pressurizer Heaters	a	
14.	PWR Pipe Cracks	c, j	See DCD subsection 1.9.4.2.3, item 14
15.	Radiation Effects on Reactor Vessel Supports	c	See DCD subsection 1.9.4, item 15
16.	BWR Main Steam Isolation Valve Leakage Control Systems	e	
17.	Loss of Offsite Power Subsequent to LOCA	a	
18.	Steam Line Break with Consequential Small LOCA	e	
19.	Safety Implications of Nonsafety Instrument and Control Power Supply Bus	e	
20.	Effects of Electromagnetic Pulse on Nuclear Power Plants	c	
21.	Vibration Qualification of Equipment	a	
22.	Inadvertent Boron Dilution Events	c, j	See DCD subsection 1.9.4.2.3, item 22
23.	Reactor Coolant Pump Seal Failures	c	See DCD subsection 1.9.4, item 23

Table 1.9-2 (Sheet 28 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
24.	Automatic Emergency Core Cooling System Switch to Recirculation	a, j	See DCD subsection 1.9.4.2.3, item 24
25.	Automatic Air Header Dump on BWR Scram System	b	
26.	Diesel Generator Loading Problems Related to SIS Reset on Loss of Offsite Power	e	
27.	Manual vs. Automated Actions	e	
28.	Pressurized Thermal Shock	e	
29.	Bolting Degradation or Failure in Nuclear Power Plants	c	See DCD subsection 1.9.4, item 29
30.	Potential Generator Missiles - Generator Rotor Retaining Rings	a	
31.	Natural Circulation Cooldown	e	
32.	Flow Blockage in Essential Equipment Caused by Corbicula	e	
33.	Correcting Atmospheric Dump Valve Opening Upon Loss of Integrated Control System Power	e	
34.	RCS Leak	a	
35.	Degradation of Internal Appurtenances in LWRs	a	
36.	Loss of Service Water	c	
37.	Steam Generator Overfill and Combined Primary and Secondary Blowdown	e	
38.	Potential Recirculation System Failure as a Consequence of Injection of Containment Paint Flakes or Other Fine Debris	a	
39.	Potential for Unacceptable Interaction Between the CRD System and Non-Essential Control Air System	e	
40.	Safety Concerns Associated with Pipe Breaks in the BWR Scram System	b	
41.	BWR Scram Discharge Volume Systems	b	
42.	Combination Primary/Secondary System LOCA	e	

Table 1.9-2 (Sheet 29 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
43.	Reliability of Air Systems	f, j	See DCD subsection 1.9.4.2.3, item 43
44.	Failure of Saltwater Cooling System	e	
45.	Inoperability of Instrumentation Due to Extreme Cold Weather	g	See DCD subsection 1.9.4, item 45
46.	Loss of 125 Volt DC Bus	e	
47.	Loss of Off-Site Power	c	
48.	LCO for Class e Vital Instrument Buses in Operating Reactors	e	
49.	Interlocks and LCOs for Redundant Class e Tie Breakers	e	
50.	Reactor Vessel Level Instrumentation in BWRs	c	
51.	Proposed Requirements for Improving the Reliability of Open Cycle Service Water Systems	g	See DCD subsection 1.9.4, item 51
52.	SSW Flow Blockage by Blue Mussels	e	
53.	Consequences of a Postulated Flow Blockage Incident in a BWR	a	
54.	Valve Operator-Related Events Occurring During 1978, 1979, and 1980	e	
55.	Failure of Class e Safety-Related Switchgear Circuit Breakers to Close on Demand	a	
56.	Abnormal Transient Operating Guidelines as Applied to a Steam Generator Overfill Event	e	
57.	Effects of Fire Protection System Actuation	c	See DCD subsection 1.9.4, item 57
58.	Inadvertent Containment Flooding	a	
59.	Technical Specification Requirements for Plant Shutdown when Equipment for Safe Shutdown is Degraded or Inoperable	d	
60.	Lamellar Tearing of Reactor Systems Structural Supports	e	
61.	SRV Line Break Inside the BWR Wetwell Airspace of Mark I and II Containments	c	

Table 1.9-2 (Sheet 30 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
62.	Reactor Systems Bolting Applications	e	
63.	Use of Equipment Not Classified as Essential to Safety in BWR Transient Analysis	a	
64.	Identification of Protection System Instrument Sensing Lines	c	
65.	Probability of Core-Melt Due to Component Cooling Water System Failures	e	
66.	Steam Generator Requirements	c	
67.2.1	Integrity of Steam Generator Tube Sleeves	d	
67.3.1	Steam Generator Overfill	e	
67.3.2	Pressurized Thermal Shock	e	
67.3.3	Improved Accident Monitoring	e, j	See DCD subsection 1.9.4.2.3, item 67.3.3
67.3.4	Reactor Vessel Inventory Measurements	e	
67.4.1	RCP Trip	e	
67.4.2	Control Room Design Review	e	
67.4.3	Emergency Operating Procedures	e	
67.5.1	Reassessment of SGTR Design Basis	d	
67.5.2	Reevaluation of SGTR Design Basis	d	
67.5.3	Secondary System Isolation	a	
67.6.0	Organizational Responses	e	
67.7.0	Improved Eddy Current Tests	e	
67.8.0	Denting Criteria	e	
67.9.0	Reactor Coolant System Pressure Control	e	
67.10.0	Supplement Tube Inspections	d	
68.	Postulated Loss of Auxiliary Feedwater System Resulting from Turbine-Driven Auxiliary Feedwater Pumps Steam Supply Line Rupture	e	

Table 1.9-2 (Sheet 31 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
69.	Make-up Nozzle Cracking in B&W Plants	c	
70.	PORV and Block Valve Reliability	g	See DCD subsection 1.9.3, item (1)(iv)
71.	Failure of Resin Demineralizer Systems and Their Effects on Nuclear Power Plant Safety	a	
72.	Control Rod Drive Guide Tube Support Pin Failures	a	
73.	Detached Thermal Sleeves	a, j	See DCD subsection 1.9.4.2.3, item 73
74.	Reactor Coolant Activity Limits for Operating Reactors	a	
75.	Generic Implications of ATWS Events at the Salem Nuclear Plant	g, j	See DCD subsection 1.9.4.2.3, item 75
76.	Instrumentation and Control Power Interactions	a	
77.	Flooding of Safety Equipment Compartments by Back-flow Through Floor Drains	e	
78.	Monitoring of Fatigue Transient Limits for Reactor Coolant System	c	
79.	Unanalyzed Reactor Vessel Thermal Stress During Natural Circulation Cooldown	c	See DCD subsection 1.9.4.2.3, item 79
80.	Pipe Break Effects on Control Rod Drive Hydraulic Lines in the Drywells of BWR Mark I and II Containments	a	
81.	Impact of Locked Doors and Barriers on Plant and Personnel Safety	a	
82.	Beyond Design Basis Accidents in Spent Fuel Pools	c, j	See DCD subsection 1.9.4.2.3, item 82
83.	Control Room Habitability	c	See DCD subsection 1.9.4.2.3, item 83
84.	CE PORVs	c	
85.	Reliability of Vacuum Breakers Connected to Steam Discharge Lines Inside BWR Containments	a	
86.	Long Range Plan for Dealing with Stress Corrosion Cracking in BWR Piping	b	

Table 1.9-2 (Sheet 32 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
87.	Failure of HPCI Steam Line Without Isolation	g	See DCD subsection 1.9.4, item 87
88.	Earthquakes and Emergency Planning	c	
89.	Stiff Pipe Clamps	h (Medium)	
90.	Technical Specifications for Anticipatory Trips	a	
91.	Main Crankshaft Failures in Transamerica DeLaval Emergency Diesel Generators	c	
92.	Fuel Crumbling During LOCA	a	
93.	Steam Binding of Auxiliary Feedwater Pumps	g	See DCD subsection 1.9.4, item 93
94.	Additional Low Temperature Overpressure Protection for Light Water Reactors	g	See DCD subsection 1.9.4, item 94
95.	Loss of Effective Volume for Containment Recirculation Spray	c	
96.	RHR Suction Valve Testing	e	
97.	PWR Reactor Cavity Uncontrolled Exposures	e	
98.	CRD Accumulator Check Valve Leakage	a	
99.	RCS/RHR Suction Line Valve Interlock on PWRs	f	
100.	OTSG Level	b	
101.	BWR Water Level Redundancy	c	
102.	Human Error in Events Involving Wrong Unit or Wrong Train	c	
103.	Design for Probable Maximum Precipitation	g	See DCD subsection 1.9.4, item 103
104.	Reduction of Boron Dilution Requirements	a	
105.	Interfacing Systems LOCA at BWRs	c	See DCD subsection 1.9.4, item 105
106.	Piping and Use of Highly Combustible Gases in Vital Areas	c	See DCD subsection 1.9.4, item 106
107.	Main Transformer Failures	a	

Table 1.9-2 (Sheet 33 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
108.	BWR Suppression Pool Temperature Limits	a	
109.	Reactor Vessel Closure Failure	a	
110.	Equipment Protective Devices on Engineered Safety Features	a	
111.	Stress Corrosion Cracking of Pressure Boundary Ferritic Steels in Selected Environments	d	
112.	Westinghouse RPS Surveillance Frequencies and Out-of-Service Times	d	
113.	Dynamic Qualification Testing of Large Bore Hydraulic Snubbers	c	See DCD subsection 1.9.4, item 113
114.	Seismic-Induced Relay Chatter	e	
115.	Enhancement of the Reliability of Westinghouse Solid State Protection System	c	
116.	Accident Management	a	
117.	Allowable Time for Diverse Simultaneous Equipment Outages	a	
118.	Tendon Anchorage Failure	f	
119.1	Piping Rupture Requirements and Decoupling of Seismic and LOCA Loads	d	
119.2	Piping Damping Values	a	
119.3	Decoupling the OBE from the SSE	d	
119.4	BWR Piping Materials	d	
119.5	Leak Detection Requirements	d	
120.	On-Line Testability of Protection Systems	c, j	See DCD subsection 1.9.4.2.3, item 120
121.	Hydrogen Control for Large, Dry PWR Containments	c	See DCD subsection 1.9.4, item 121
122.1.a	Failure of Isolation Valves in Closed Position	e	
122.1.b	Recovery of Auxiliary Feedwater	e	
122.1.c	Interruption of Auxiliary Feedwater Flow	e	

Table 1.9-2 (Sheet 34 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
122.2	Initiating Feed-and-Bleed	c	
122.3	Physical Security System Constraints	a	
123.	Deficiencies in the Regulations Governing DBA and Single-Failure Criteria Suggested by the Davis-Besse Event of June 9, 1985	a	
124.	Auxiliary Feedwater System Reliability	g	See DCD subsection 1.9.4, item 124
125.I.1	Availability of the STA	a	
125.I.2.a	Need for a Test Program to Establish Reliability of the PORV	e	
125.I.2.b	Need for PORV Surveillance Tests to Confirm Operational Readiness	e	
125.I.2.c	Need for Additional Protection Against PORV Failure	a	
125.I.2.d	Capability of the PORV to Support Feed-and-Bleed	e	
125.I.3	SPDS Availability	c	
125.I.4	Plant-Specific Simulator	a	
125.I.5	Safety Systems Tested in All Conditions Required by Design Basis Analysis	a	
125.I.6	Valve Torque Limit and Bypass Switch Settings	a	
125.I.7.a	Recover Failed Equipment	a	
125.I.7.b	Realistic Hands-On Training	a	
125.I.8	Procedures and Staffing for Reporting to NRC Emergency Response Center	a	
125.II.1.a	Two-Train AFW unavailability	a	
125.II.1.b	Review Existing AFW Systems for Single Failure	e	
125.II.1.c	NUREG-0737 Reliability Improvements	a	
125.II.1.d	AFW/Steam and Feedwater Rupture Control System/ICS Interactions in B&W Plants	a	
125.II.2	Adequacy of Existing Maintenance Requirements for Safety-Related Systems	a	

Table 1.9-2 (Sheet 35 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
125.II.3	Review Steam/Feedline Break Mitigation Systems for Single Failure	a	
125.II.4	Thermal Stress of OTSG Components	a	
125.II.5	Thermal-Hydraulic Effects of Loss and Restoration of Feedwater on Primary System Components	a	
125.II.6	Reexamine PRA-Based Estimates of the Likelihood of a Severe Core Damage Accident Based on Loss of All Feedwater	a	
125.II.7	Reevaluate Provisions to Automatically Isolate Feedwater from Steam Generator During a Line Break	c	
125.II.8	Reassess Criteria for Feed-and-Bleed Initiation	a	
125.II.9	Enhanced Feed-and-Bleed Capability	a	
125.II.10	Hierarchy of Impromptu Operator Actions	a	
125.II.11	Recovery of Main Feedwater as Alternative to AFW	a	
125.II.12	Adequacy of Training Regarding PORV Operation	a	
125.II.13	Operator Job Aids	a	
125.II.14	Remote Operation of Equipment Which Must Now Be Operated Locally	a	
126.	Reliability of PWR Main Steam Safety Valves	d	
127.	Testing and Maintenance of Manual Valves in Safety-Related Systems	a	
128.	Electrical Power Reliability	h (High)	See DCD subsection 1.9.4, item 128
129.	Valve Interlocks to Prevent Vessel Drainage During Shutdown Cooling	a	
130.	Essential Service Water Pump Failures at Multiplant Sites	f	See DCD subsection 1.9.4, item 130
131.	Potential Seismic Interaction Involving the Movable In-Core Flux Mapping System in Westinghouse Plants	e	
132.	RHR Pumps Inside Containment	a	

Table 1.9-2 (Sheet 36 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
133.	Update Policy Statement on Nuclear Plant Staff Working Hours	d	
134.	Rule on Degree and Experience Requirements	c	
135.	Steam Generator and Steam Line Overfill	c	See DCD subsection 1.9.4, item 135
136.	Storage and Use of Large Quantities of Cryogenic Combustibles On Site	d	
137.	Refueling Cavity Seal Failure	a	
138.	Deinerting Upon Discovery of RCS Leakage	a	
139.	Thinning of Carbon Steel Piping in LWRs	d	
140.	Fission Product Removal Systems	a	
141.	LBLOCA With Consequential SGTR	a	
142.	Leakage Through Electrical Isolators in Instrumentation Circuits	c	See DCD subsection 1.9.4, item 142
143.	Availability of Chilled Water Systems	c, j	See DCD subsection 1.9.4.2.3, item 143
144.	Scram Without a Turbine/Generator Trip	a	
145.	Actions to Reduce Common Cause Failures	c	
146.	Support Flexibility of Equipment and Components	d	
147.	Fire-Induced Alternate Shutdown Control Room Panel Interactions	d	
148.	Smoke Control and Manual Fire-Fighting Effectiveness	d	
149.	Adequacy of Fire Barriers	a	
150.	Overpressurization of Containment Penetrations	a	
151.	Reliability of Recirculation Pump Trip During an ATWS	c	
152.	Design Basis for Valves That Might Be Subjected to Significant Blowdown Loads	a	
153.	Loss of Essential Service Water in LWRs	c, j	See DCD subsection 1.9.4.2.3, item 153

Table 1.9-2 (Sheet 37 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
154.	Adequacy of Emergency and Essential Lighting	a	
155.1	More Realistic Source Term Assumptions	g	
155.2	Establish Licensing Requirements For Non-Operating Facilities	d	
155.3	Improve Design Requirements For Nuclear Facilities	a	
155.4	Improve Criticality Calculations	a	
155.5	More Realistic Severe Reactor Accident Scenario	a	
155.6	Improve Decontamination Regulations	a	
155.7	Improve Decommissioning Regulations	a	
156	Systematic Evaluation Program	f	
157	Containment Performance	c	
158	Performance Of Safety-Related Power-Operated Valves Under Design Basis Conditions	c	
159	Qualification Of Safety-Related Pumps While Running On Minimum Flow	a	
160	Spurious Actuations Of Instrumentation Upon Restoration Of Power	a	
161	Use Of Non-Safety-Related Power Supplies In Safety-Related Circuits	a	
162	Inadequate Technical Specifications For Shared Systems At Multiplant Sites When One Unit Is Shut Down	a	
163	Multiple Steam Generator Tube Leakage	h (Medium)	See DCD subsection 1.9.4.2.3, item 163
164	Neutron Fluence In Reactor Vessel	a	
165	Spring-Actuated Safety And Relief Valve Reliability	c	
166	Adequacy Of Fatigue Life Of Metal Components	c	
167	Hydrogen Storage Facility Separation	a	
168	Environmental Qualification Of Electrical Equipment	f	See DCD subsection 1.9.4.2.3, item 168

Table 1.9-2 (Sheet 38 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
169	BWR MSIV Common Mode Failure Due To Loss Of Accumulator Pressure	a	
170	Fuel Damage Criteria For High Burnup Fuel	c	
171	ESF Failure From LOOP Subsequent To A LOCA	c	
172	Multiple System Responses Program	e	
173.A	Spent Fuel Storage Pool Operating Facilities	c	
173.B	Spent Fuel Storage Pool Permanently Shutdown Facilities	c	
174	Fastener Gaging Practices	c	
175	Nuclear Power Plant Shift Staffing	c	
176	Loss Of Fill-Oil In Rosemount Transmitters	c	
177	Vehicle Intrusion At TMI	g	
178	Effect Of Hurricane Andrew On Turkey Point	d	
179	Core Performance	c	
180	Notice Of Enforcement Discretion	d	
181	Fire Protection	d	
182	General Electric Extended Power Uprate	b	
183	Cycle-Specific Parameter Limits In Technical Specifications	d	
184	Endangered Species	d	
185	Control of Recriticality following Small-Break LOCA in PWRs	h (High)	See DCD subsection 1.9.4.2.3, item 185
186	Potential Risk and Consequences of Heavy Load Drops	a	
187	The Potential impact of Postulated Cesium Concentration on Equipment Qualification in the Containment Sump in Nuclear Power Plants.	a	
188	Steam Generator Tube Leaks/Ruptures Concurrent with Containment Bypass	a	
189	Susceptibility of Ice Condenser Containments to Early Failure from Hydrogen Concentration during a Severe Accident	a	

Table 1.9-2 (Sheet 39 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
Human Factors Issues			
190	Fatigue Evaluation Of Metal Components For 60-Year Plant Life	c	
191	Assessment Of Debris Accumulation On PWR Sump Performance	h (High)	See DCD subsections 6.3.2.2.7 and 1.9.4.2.3, item 191
HF1.1	Shift Staffing	f	
HF1.2	Engineering Expertise on Shift	c	
HF1.3	Guidance on Limits and Conditions of Shift Work	c	
HF2.1	Evaluate Industry Training	d	
HF2.2	Evaluate INPO Accreditation	d	
HF2.3	Revise SRP Section 13.2	d	
HF3.1	Develop Job Knowledge Catalog	d	
HF3.2	Develop License Examination Handbook	d	
HF3.3	Develop Criteria for Nuclear Power Plant Simulators	e	
HF3.4	Examination Requirements	e	
HF3.5	Develop Computerized Exam System	d	
HF4.1	Inspection Procedure for Upgraded Emergency Operating Procedures	c, i	
HF4.2	Procedures Generation Package Effectiveness Evaluation	d	
HF4.3	Criteria for Safety-Related Operator Actions	e	
HF4.4	Guidelines for Upgrading Other Procedures	c, j	See DCD subsection 1.9.4.2.4, item HF4.4
HF4.5	Application of Automation and Artificial Intelligence	e	
HF5.1	Local Control Stations	c	See DCD subsection 1.9.4, item HF5.1
HF5.2	Review Criteria for Human Factors Aspects of Advanced Controls and Instrumentation	g	See DCD subsection 1.9.4, item HF5.2

Table 1.9-2 (Sheet 40 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
HF5.3	Evaluation of Operational Aid Systems	e	
HF5.4	Computers and Computer Displays	e	
HF6.1	Develop Regulatory Position on Management and Organization	e	
HF6.2	Regulatory Position on Management and Organization at Operating Reactors	e	
HF7.1	Human Error Data Acquisition	d	
HF7.2	Human Error Data Storage and Retrieval	d	
HF7.3	Reliability Evaluation Specialist Aids	d	
HF7.4	Safety Event Analysis Results Applications	d	
HF8	Maintenance and Surveillance Program	c	
Chernobyl Issues			
CH1.1A	Symptom-Based EOPs	d	
CH1.1B	Procedure Violations	d	
CH1.2A	Test, Change, and Experiment Review Guidelines	d	
CH1.2B	NRC Testing Requirements	d	
CH1.3A	Revise Regulatory Guide 1.47	d	
CH1.4A	Engineered Safety Feature Availability	d	
CH1.4B	Technical Specification Bases	d	
CH1.4C	Low Power and Shutdown	d	
CH1.5	Operating Staff Attitudes Toward Safety	d	
CH1.6A	Assessment of NRC Requirements on Management	d	
CH1.7A	Accident Management	d	
CH2.1A	Reactivity Transients	d	
CH2.2	Accidents at Low Power and at Zero Power	e	
CH2.3A	Control Room Habitability	e	
CH2.3B	Contamination Outside Control Room	d	

Table 1.9-2 (Sheet 41 of 41)

LISTING OF UNRESOLVED SAFETY ISSUES AND GENERIC SAFETY ISSUES

Action Plan Item/Issue No.	Title	Applicable Screening Criteria	Notes
CH2.3C	Smoke Control	d	
CH2.3D	Shared Shutdown Systems	d	
CH2.4A	Firefighting With Radiation Present	d	
CH3.1A	Containment Performance	d	
CH3.2A	Filtered Venting	d	
CH4.1	Size of the Emergency Planning Zones	a	
CH4.2	Medical Services	a	
CH4.3A	Ingestion Pathway Protective Measures	d	
CH4.4A	Decontamination	d	
CH4.4B	Relocation	d	
CH5.1A	Mechanical Dispersal in Fission Product Release	d	
CH5.1B	Stripping in Fission Product Release	d	
CH5.2A	Steam Explosions	d	
CH5.3	Combustible Gas	a	
CH6.1A	The Fort St. Vrain Reactor and the Modular HTGR	a	
CH6.1B	Structural Graphite Experiments	d	
CH6.2	Assessment	d	

Notes:

a. Issue has been prioritized as **Low, Drop** or has not been prioritized.
b. Issue is not an AP1000 design issue. Issue is applicable to GE, B&W, or CE designs only.
c. Issue resolved with no new requirements.
d. Issue is not a design issue (Environmental, Licensing, or Regulatory Impact Issue; or covered in an existing NRC program).
e. Issue superseded by one or more issues.
f. Issue is not an AP1000 design certification issue. Issue is applicable to current operating plants or responsibility of Combined License applicant.
g. Issue is resolved by establishment of new regulatory requirements and/or guidance.
h. Issue is unresolved pending generic resolution (for example, prioritized as **High, Medium**, or possible resolution identified).
i. The AP600 DSER (Draft NUREG-01512) identified this item as not being required to be addressed by 10 CFR 52.47.
j. The AP600 DSER (Draft NUREG-01512) identified this item as required to be discussed.

APPENDIX 1A

CONFORMANCE WITH REGULATORY GUIDES

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions

DIVISION 1 – Power Reactors

Reg. Guide 1.1, Rev. 0, 11/70 – Net Positive Suction Head For Emergency Core Cooling and Containment Heat Removal System Pumps

General		N/A	The AP1000 passive safety systems make maximum use of natural phenomena (gravity, natural circulation, and gas driven injection) and fail-safe position valves, and thus require no active pumps, diesel-generators, or fans. The AP1000 normal residual heat removal system is designed to take suction from the cask loading pit, the in-containment refueling water storage tank, and from containment, however it is not a safety-related system, and does not control or mitigate the consequences of an accident in the licensing basis accident analyses.

Reg. Guide 1.2 – Withdrawn

Reg. Guide 1.3, Rev. 2, 6/74 – Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Boiling Water Reactors

General		N/A	Applies to boiling water reactors only.

Reg. Guide 1.4, Rev. 2, 6/74 – Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Pressurized Water Reactors

General		Exception	The guidance of Reg. Guide 1.183, "Alternative Radiological Source Terms For Evaluating Design Basis Accidents at Nuclear Power Reactors" will be followed instead of Reg. Guide 1.4.

Reg. Guide 1.5, Rev. 0, 3/71 – Assumptions Used for Evaluating the Potential Radiological Consequences of a Steamline Break Accident for Boiling Water Reactors

General		N/A	Applies to boiling water reactors only.

Reg. Guide 1.6, Rev. 0, 3/71 – Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems

General		Exception	The AP1000 main ac power system is a nonsafety-related system. This regulatory guide is applicable only to the Class 1E dc and UPS system.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
D.1		Conforms	Guidance applies only to the Class 1E dc and UPS system, since the AP1000 ac power system is a nonsafety-related system.
D.2		N/A	The main ac power system is a nonsafety-related system. Therefore, this regulatory position is not applicable. However, the AP1000 design includes connections to a preferred (offsite) power source and two nonsafety-related onsite standby diesel generators.
D.3		Conforms	
D.4		N/A	See comment on Criteria Section D.2.
D.5		N/A	See comment on Criteria Section D.2.
Reg. Guide 1.7, Rev. 2, 11/78 – Control of Combustible Gas Concentrations in Containment Following a Loss of Coolant Accident			
C.1		Conforms	Mixing of the containment atmosphere is accomplished through natural passive processes (natural circulation), not with an active system.
C.2		Conforms	
C.3	Regulatory Guide 1.29 Regulatory Guide 1.26	Conforms	The hydrogen recombiners are passive autocatalytic recombiners and nonsafety-related. They do not require and are not supplied with power.
C.4		Conforms	
C.5		Conforms	
C.6		Conforms	
Reg. Guide 1.8, Rev. 3, 5/00 – Qualification and Training of Personnel for Nuclear Power Plants			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility. See Section 13.2 for the Combined License information item on training.
Reg. Guide 1.9, Rev. 2, 12/79 – Selection, Design, and Qualification of Diesel Generator Units Used as Standby (Onsite) Electric Power Systems at Nuclear Power Plants			
General		N/A	Guidelines apply to Class 1E diesel-generators. They are not applicable to the AP1000.
C.1-14		N/A	Guidelines apply to Class 1E diesel-generators. They are not applicable to the AP1000.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.10 – Withdrawn			
Reg. Guide 1.11, Rev. 0, 3/71 – Instrument Lines Penetrating Primary Reactor Containment			
General		Conforms	The AP1000 has no instrument lines penetrating primary reactor containment.
C.1.a		Conforms	
C.1.b	10 CFR 100	Conforms	
C.1.c-e		Conforms	
C.2		Conforms	
E.1		Conforms	
E.2		N/A	This section applies only to plants for which a notice of hearing on application for construction permit was published between January 5, 1967, and December 30, 1969. Therefore, it is not applicable to the AP1000.
E.3		N/A	This section applies only to plants for which a notice of hearing on application for construction permit was published on or before December 30, 1966. Therefore, it is not applicable to the AP1000.
Reg. Guide 1.12, Rev. 2, 3/97 – Instrumentation for Earthquakes			
C.1		Exception	Two elevations (excluding the foundation) on a structure internal to the containment are specified in the draft regulatory guide. A second sensor internal to the containment is not provided because access to a sensor at a lower elevation is inconsistent with maintaining occupational radiation exposures as low as reasonably achievable (ALARA) and the containment seismic analyses show such a location to be unnecessary. The response of the containment internal structures is well represented by the response obtained at elevation 138′-0″. Two independent Category I structure foundations where the response is different from that of the containment structure are also specified. Since all seismic Category I structures are part of the nuclear island, which has a common basemat, no additional foundation sensors are required.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.2		Conforms	Should the seismic response at multiple units at the same site be evaluated as not essentially the same, multiple seismic monitoring systems will be installed at the units. If the seismic response is essentially the same at the other units, the system will be installed at only one unit; however annunciation will be provided in the main control room of each unit.
C.3		Conforms	
C.4		Conforms	The system power panel provides timing signals to components of the entire system. The triaxial acceleration sensor input signals exceeding a preset value are used as the actuation signal for system recording and analysis.
C.5		Conforms	
C.6		Conforms	The triaxial acceleration sensor input signals exceeding a preset value are used as the actuation signal for system recording and analysis.
C.7		Conforms	See Criteria Section C.2.
C.8		Combined License applicant	Maintenance procedures will be developed by the Combined License applicant.
Reg. Guide 1.13, Rev. 1, 12/75 – Spent Fuel Storage Facility Design Basis			
C.1		Conforms	
C.2		Conforms	
C.3		Conforms	
C.4	Regulatory Guide 1.25	Exception	The ventilation system is not designed to mitigate the consequences of a fuel handling accident.
C.5		Conforms	
C.6		Conforms	
C.7		Conforms	
C.8		Exception	Normal makeup supply (demineralized water) is not seismic Category I. Long-term post-accident supply piping is seismic Category I.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.14, Rev. 1, 8/75 – Reactor Coolant Pump Flywheel Integrity			
1.a	ASTM A.20	Exception	The flywheel is made of a depleted uranium casting of high quality. Therefore, the specific guidelines in this section are not directly applicable to the AP1000.
1.b		Exception	The test methods used to verify the fracture toughness of the uranium casting are not the same as those required in material specifications for steel such as Charpy V-notch and upper shelf energy determinations.
1.c		N/A	This guideline is not applicable to uranium castings. Therefore, the guideline is not applicable to the AP1000 canned-motor pump.
1.d		Conforms	The uranium casting requires no welding. The enclosure is welded using specifications meeting ASME Code requirements. The enclosure, including the welds, are considered in the analysis of potential missiles.
2.a-b		Conforms	
2.c-e	ASME Code, Section III	Exception	The limits and methods of ASME Code, Section III, Paragraph F-1331.1(b), (replacement for Paragraph F-1323.1) are not directly applicable to a uranium casting. The calculated stress levels in the flywheel are evaluated against the ASME Code, Section III, Subsection NG stress limits used as guidelines and the recommended stress limits in Positions 4.a and 4.c of the Standard Review Plan 5.4.1.1.
2.f		Exception	The calculated stress levels in the flywheel satisfy the ASME Code, Section III, Subsection NG stress limits used as guidelines and the recommended stress limits in Position 4.a of the Standard Review Plan 5.4.1.1.
2.g		Conforms	
3		Conforms	
4.a	ASME Code, Section III, NB-2545 or NB-2546, NB-2540, NB-2530	Exception	The inspections and guidelines referenced in the regulatory guide were developed for steel flywheels in shaft seal pumps. Inspection of the flywheel inside the flywheel assembly following a spin test is not practical. The ultrasonic inspection of the flywheel prior to final assembly is in conformance with the requirements of the ASME Code, Section III, paragraph NB-2574, for

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			ferritic steel castings, including the use of the procedures outlined in SA-609 (ASTM-A-609). Machined surfaces of the uranium flywheel undergo liquid penetrant inspection prior to final assembly. The liquid penetrant inspection conforms with the requirements of the ASME Code, Section III, paragraph NB-2576, including the use of the procedures outlined in SA-165 (ASTM-A-165).
4.b	ASME Code, Section XI	Exception	Inservice inspection of the flywheel assembly is not required to support safe operation of the canned motor reactor coolant pump. Planned, routine inspections of the flywheel assembly requires considerable occupational radiation exposure and are not recommended. Inservice inspection of the uranium casting requires extensive disassembly. Postulated missiles from the failure of the flywheel are contained within the stator shell and the pressure boundary is not breached. Vibration of the shaft due to a small flywheel fracture or leak in the enclosure does not result in stresses in the pressure boundary of sufficient magnitude to result in a break in the primary pressure boundary.

Reg. Guide 1.15 – Withdrawn

Reg. Guide 1.16, Rev. 4, 8/75 – Reporting of Operating Information – Appendix A Technical Specifications

General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.

Reg. Guide 1.17 – Withdrawn

Reg. Guide 1.18 – Withdrawn

Reg. Guide 1.19 – Withdrawn

Reg. Guide 1.20, Rev. 2, 5/76 – Comprehensive Vibration Assessment Program For Reactor Internals During Preoperational and Initial Startup Testing

General		Conforms	The AP1000 internals are similar to those for a three-loop XL Westinghouse 17 x 17 robust fuel assembly core internals, a core shroud and the new incore instrumentation system. The neutron panels are eliminated from the downcomer region. The upper internals are not significantly changed from standard designs.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			An internals vibration measurement program is conducted during hot functional testing. The results are evaluated based on pre-established allowable levels. During hot functional testing the AP1000 internals are subjected to operational system flow conditions that are similar to those imposed on previous 3XL three-loop designs. The duration of the hot functional flow testing is the same as that for the previous design. Pre- and post-test inspections are conducted to confirm that the AP1000 internals experience no excessive motion or wear.
C.1		Conforms	Although the AP1000 internals do not represent a first of a kind or unique design on the basis of the arrangement, design, size, or operating conditions, for the purposes of the reactor internals preoperational test program, the first operational AP1000 reactor vessel internals are classified as a prototype. Subsequent plants will be classified as Non-Prototype Category I based on the designation of the first AP1000 as a Valid Prototype. See subsections 3.9.2.3 and 3.9.2.4 for additional information on the vibration assessment of the reactor vessel internals.
C.2		Conforms	A comprehensive vibration assessment program will be developed for the first AP1000 reactor vessel internals. With regard to transients, data are acquired only during the hot functional test. Additionally, data are calculated over the ranges of hot functional test temperatures and during startup, shutdown, and steady-state operation of various combinations of reactor coolant pumps. See subsection 3.9.8 for information to be provided by the Combined License applicant.
C.3		Conforms	Subsequent to completion of the vibration assessment program for the first AP1000 reactor vessel internals, the vibration analysis program will address the criteria for Non-prototype Category I internals.

Reg. Guide 1.21, Rev. 1, 6/74 – Measuring Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents From Light-Water-Cooled Nuclear Power Plants

General		Conforms	The design guidance of this regulatory guide for the selection of locations and type of effluent measurements to cover major or potentially significant pathways of release of radioactive materials during normal reactor operation, including anticipated operational

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			occurrences, are incorporated in the plant design and in the requirements of the radiological effluent technical specifications. The calibration of effluent monitoring systems is performed according to written plant procedures. This is the Combined License applicant's responsibility.
C.1		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
C.2		Conforms	
C.3-14		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
Reg. Guide 1.22, Rev. 0, 2/72 – Periodic Testing of Protection System Actuation Functions			
General		Conforms	Safety actuation circuitry is provided with a capability for testing with the reactor at power. The protection system, including the engineered safety features test cabinet design, conforms to this regulatory guide. The protection functions are tested at power to the greatest extent practical. Only the device function and/or system level function is not universally tested. The logic associated with the devices has the capability for testing at power, at the subsystem and/or component level.
D.1		Conforms	The AP1000 protection system is designed to permit periodic testing.
D.2-4		Conforms	
Reg. Guide 1.23, Second Proposed Rev. 1, 4/86 – Onsite Meteorological Programs			
General		Conforms	The onsite meteorological measurement program is site-specific and will be defined by the Combined License applicant. The number and location of meteorological instrument towers are determined by actual site parameters. See subsection 2.3.6 for the Combined License applicant information item on the onsite meteorological program. The data display and processing system has the capability to record the data from the meteorological instruments and display the information in the main control room.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions

Reg. Guide 1.24, Rev. 0, 3/72 – Assumptions Used for Evaluating the Potential Radiological Consequences of a Pressurized Water Reactor Radioactive Gas Storage Tank Failure

General		N/A	This regulatory guide applies to the evaluation of a waste gas storage tank failure. The AP1000 design does not include waste gas storage tanks. Therefore, it is not applicable to the AP1000.

Reg. Guide 1.25, Rev. 0, 3/72 – Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors

General		Exception	The guidance of Reg. Guide 1.183, "Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors" will be followed instead of Reg. Guide 1.25.

Reg. Guide 1.26, Rev. 3, 2/76 – Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containment Components of Nuclear Power Plants

C.1		Exception	A portion of the chemical and volume control system that is defined as reactor coolant pressure boundary uses an alternate classification in conformance with the requirements of 10 CFR 50.55a(a)(3). The alternate classification is discussed in Section 5.2.
C.1.a		Exception	For the AP1000 plant design, Quality Group B is reserved for the containment boundary including any extensions such as containment isolation valves and associated piping. Quality Group C is essentially equivalent quality except that it has less stringent ISI. For equipment such as passive safety system accumulators, minor leakage is not a problem for the following reasons: a. It is located inside containment so activity releases are contained. b. Minor leakage does not affect its functional performance, especially considering the limited duration of post-accident operation. c. There is continuous water level and gas pressure monitoring of the passive safety system accumulators that detects leaks. This approach results in the change of quality group (from Quality Group B to Quality Group C) for various components such as the IRWST. Portions of systems

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			that provide emergency core cooling system functions and are constructed using ASME Code, Section III, Class 3 criteria have the additional requirement that radiography will be conducted on a random sample of welds during construction, see subsection 3.2.2.5.
C.1.b		Exception	The AP1000 residual heat removal system is a nonsafety-related system, but it is classified as Quality Group C. The passive core cooling system provides the safety-related function that the residual heat removal system provides in current plants with active safety-related systems.
C.1.c		N/A	Applies to boiling water reactors only.
C.1.d		Conforms	Portions of the feedwater and steam systems are Quality Group B, up to the isolation valves.
C.1.e		Conforms	
C.2.a		Conforms	The component cooling water and the service water systems are Quality Group D since they perform no safety-related functions.
C.2.b		Conforms	Component cooling water is not required for safe shutdown of the AP1000. The reactor cooling pumps do not have seals and do not require seal water supply.
C.2.c		Conforms	
C.2.d		N/A	Regulatory Guide 1.143 supersedes this guideline.
C.2.e		N/A	Regulatory Guide 1.143 supersedes this guideline.
C.3		Exception	Systems that are normally radioactive are classified as Quality Group D. AP1000 also classifies as Quality Group D, nonsafety-related systems and components which have functions that have been identified as important as part of the implementation of the regulatory treatment of nonsafety-related systems or as defense-in-depth systems. Some structures, systems, and components that have the potential to be contaminated with radioactive fluids but normally do not contain radioactive fluids are not classified as Quality Group D.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.27, Rev. 2, 1/76 – Ultimate Heat Sink for Nuclear Power Plants			
C.1		Conforms	The passive containment cooling system water storage tank is sized to provide water cooling to the containment vessel and provide heat removal to meet the requirements of General Design Criterion 38 to reduce and maintain the containment temperature and pressure following a postulated loss-of-coolant accident for 3 days following passive containment cooling system actuation. This water delivery is done in conjunction with the flow of air over the containment shell to provide the containment cooling. After 3 days of water delivery from the PCCWST, the PCS cooling water supply is continued through either: • simple operator action via installed safety-related piping and connection utilizing offsite or available onsite supplies of water and an offsite pump to resupply water to the tank; or, • simple operator action utilizing onsite seismically analyzed pumps, piping and 4 days of water inventory within the passive containment cooling ancillary water storage tank to resupply the PCCWST. Supplemental supplies would then be available from either onsite storage facilities or an offsite source. Since the passive containment cooling system can function with replenished water supplies from either onsite or offsite, the system meets the guideline of providing an ultimate heat sink for more than 30 days.
C.2		Conforms	The AP1000 design conforms to this regulatory position, provided that the definition of a single failure of a man-made structure does not include the safety-related, seismically-designed containment structure assembly. The AP1000 uses the atmosphere as the ultimate heat sink. A baffle located between the containment shell and the shield building sustains the natural circulation that provides for air flow over the containment shell to carry heat away. The baffle is composed of a large number of panels and will continue to function if damaged by an external missile passing through the air vents in the shield building.
C.3		Conforms	The seismically-designed passive containment cooling system water storage, integral to the containment structure meets this regulatory position.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.28, Rev. 3, 8/85 – Quality Assurance Program Requirements (Design and Construction)			
General	ANSI/ASME N45.2-1977 ANSI/ASME NQA-1-1983 through NQA-1a-1983 Addenda	Conforms	The Westinghouse quality assurance program is described in Chapter 17. Refer to "Westinghouse Electric Company Quality Management System" (QMS) referenced therein for Westinghouse positions on regulatory guides within the scope of the quality assurance program. In some cases current industry consensus standards have replaced the standards specifically referenced by certain regulatory guides. In particular, the N45.2 series standards have been replaced by ASME NQA-1 and NQA-2. Therefore, the "Quality Management System" may reference ASME NQA-1 and NQA-2 rather than the N45.2 series standards when describing the Westinghouse position. QMS Revision 4 complies with ASME NQA-1-1994.
2.	Criteria 17 10 CFR 50 Appendix B	Conforms	
Reg. Guide 1.29, Rev. 3, 9/78 – Seismic Design Classification			
C.1.a		Conforms	
C.1.b		Conforms	
C.1.c		Conforms	
C.1.d		Exception	The AP1000 normal residual heat removal system is nonsafety-related. The safety-related function of decay heat removal is provided by the safety-related passive residual heat removal heat exchanger of the passive core cooling system that is seismic Category I. The spent fuel pool cooling system does not have active components that are required for the safety-related decay heat removal function. This function is provided passively through a large heat sink of water in the pool. The spent fuel pool is sized to keep the fuel covered for at least 72 hours without active cooling or makeup following a loss of ac power sources. The 72-hour sizing calculation accounts for the maximum loss of water due to the rupture of non-seismic piping. Seismic Category I components within the spent fuel pool cooling system include the containment penetration, the connections for makeup, and the spent fuel pool (refueling system).
C.1.e		N/A	Applies to boiling water reactors only.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.1.f		Conforms	
C.1.g		Exception	The AP1000 does not have a safety-related auxiliary feedwater system. The safety-related decay heat removal function is provided by the passive residual heat removal heat exchanger. The safety-related functions of the essential service water system are provided by the passive residual heat removal heat exchangers and the passive containment cooling system. The component cooling system is a nonsafety-related system, since it performs no safety-related functions.
C.1.h		Conforms	
C.1.i		N/A	The diesel-generators are nonsafety-related. Therefore, this section is not applicable to the AP1000.
C.1.j		Conforms	
C.1.k		Conforms	
C.1.l		Conforms	
C.1.m		Conforms	
C.1.n		Exception	Structures or equipment whose failure results in incapacitating injury to the occupants of the main control room are classified as seismic Category II and covered under Position 2 of this regulatory guide.
C.1.o		Conforms	
C.1.p		Conforms	
C.1.q		Conforms	
C.2		Conforms	
C.3		Conforms	
C.4		Conforms	
Reg. Guide 1.30, Rev. 0, 8/72 – Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment			
General	ANSI/ASME N45.2.4-1972	N/A	Not applicable to AP1000 design certification. This is the responsibility of the Combined License applicant. See Section 17.5 for the Combined License information item.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.31, Rev. 3, 4/78 – Control of Ferrite Content in Stainless Steel Weld Metal			
General		Conforms	
C.1-5		Conforms	
Reg. Guide 1.32, Rev. 2, 2/77 – Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants			
1.	IEEE Std. 308-1974	Exception	Regulatory Guide 1.32 endorses IEEE Std. 308-1974 (Reference 5), which has been superseded by IEEE Std. 308-1991(Reference 6). The AP1000 uses the latest version of the industry standards (as of 4/2001). This version is not endorsed by a regulatory guide but its use should not result in deviation from the design philosophy otherwise stated in Regulatory Guide 1.32. The guidelines are applicable to the Class 1E dc and UPS system only. There are no safety-related ac power systems in the AP1000.
1.a	Regulatory Guide 1.93	N/A	The AP1000 has no safety-related ac power system. Therefore, the guidelines specified in this criterion section recommending the availability of offsite power "within a few seconds" is not applicable.
1.b	IEEE Std. 308-1974, Section 5.3.4	Exception	See comment on Criterion Section 1.
1.c	IEEE Std. 450-1975	N/A	Not applicable to AP1000 design certification. This is a Combined License applicant responsibility.
1.d	Regulatory Guide 1.6 Regulatory Guide 1.75	Exception	The guidelines are applicable to the Class 1E dc and UPS system only. There are no safety-related ac power systems in the AP1000.
1.e	Regulatory Guide 1.75	Exception	The guidelines are applicable to the Class 1E dc and UPS system only. There are no safety-related ac power systems in the AP1000.
1.f	Regulatory Guide 1.9	N/A	Guidelines apply to Class 1E diesel generators. Therefore, they are not applicable to the AP1000.
2.a	IEEE Std. 308-1974, Section 8.2, 8.3.1; Regulatory Guide 1.81	N/A	The AP1000 is a single-unit plant. Therefore, this is not applicable to the AP1000.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
2.b.	Regulatory Guide 1.93	Exception	The guidelines are applicable to the Class 1E dc and UPS system only. There are no safety-related ac power systems in the AP1000. See comments on Regulatory Guide 1.93.
Reg. Guide 1.33, Rev. 2, 2/78 – Quality Assurance Program Requirements (Operation)			
General	ANSI N18.7-1976 ANS-3.2	N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility. See Section 17.5 for the Combined License information item.
Reg. Guide 1.34, Rev. 0, 12/72 – Control of Electroslag Weld Properties			
General	ASME Code, Sections III and IX	Conforms	The AP1000 prohibits the use of electroslag welding on reactor coolant pressure boundary components. AP1000 safety-related components that use electroslag welding conform to the provisions of the ASME Code and this regulatory guide.
C.1-5		Conforms	
Reg. Guide 1.35, Rev. 3, 7/90 – Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments			
General		N/A	The AP1000 does not have a concrete containment and does not use a prestressing tendon in the containment structure. Therefore, this regulatory guide is not applicable to the AP1000.
Reg. Guide 1.35.1, Rev. 0, 7/90 – Determining Prestressing Forces for Inspection of Prestressed Concrete Containments			
General		N/A	The AP1000 does not have a concrete containment and does not use a prestressing tendon in the containment structure. Therefore, this regulatory guide is not applicable to the AP1000.
Reg. Guide 1.36, Rev. 0, 2/73 – Nonmetallic Thermal Insulation for Austenitic Stainless Steel			
General		Conforms	
C.1		Conforms	
C.2.a	ASTM C692-71 RDT M12-1T	Conforms	
C.2.b		Conforms	

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.3-4		Conforms	

Reg. Guide 1.37, Rev. 0, 3/73 – Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water Cooled Nuclear Power Plants

General	ANSI N45.2.1-1973	Exception	The ANSI N45.2 series of standards that are referenced by the current revisions of the Quality Assurance regulatory guides have been replaced by ASME NQA-1 and NQA-2. ANSI N45.2.1, which is referenced in Regulatory Guide 1.37, has been incorporated into NQA-2 Part 2.1. The technical requirements specified in ANSI N45.2.1 and NQA-2 Part 2.1 are compatible. Therefore, compliance with NQA-2 Part 2.1 satisfies Regulatory Guide 1.37. See Section 17.5 for the Combined License information item.

Reg. Guide 1.38, Rev. 2, 5/77 – Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage and Handling of Items for Water-Cooled Nuclear Power Plants

General	ANSI N45.2.2-1972	Exception	The ANSI N45.2 series of standards that are referenced by the current revisions of the Quality Assurance regulatory guides have been replaced by ASME NQA-1 and NQA-2. Refer to the Regulatory Guide 1.28 position. See Section 17.5 for the Combined License information item.

Reg. Guide 1.39, Rev. 2, 9/77 – Housekeeping Requirements for Water-Cooled Nuclear Power Plants

General	ANSI N45.2.3-1973	Exception	The ANSI N45.2 series of standards that are referenced by the current revisions of the Quality Assurance regulatory guides have been replaced by ASME NQA-1 and NQA-2. Refer to the Regulatory Guide 1.28 position. See Section 17.5 for the Combined License information item.

Reg. Guide 1.40, Rev. 0, 3/73 – Qualification Tests of Continuous-Duty, Motors Installed Inside the Containment of Water-Cooled Nuclear Power Plants

General	IEEE Std. 334-1971	N/A	The AP1000 does not have continuous-duty safety-related motors installed inside the containment. Therefore, the regulatory guide is not applicable to the AP1000.

Reg. Guide 1.41, Rev. 0, 3/73 – Preoperational Testing of Redundant On-Site Electric Power Systems to Verify Proper Load Group Assignments

General		Exception	The guidelines are followed for Class 1E dc power systems during the preoperational testing of AP1000 redundant onsite electric power systems to verify proper

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			load group assignments, except as follows. Complete preoperational testing of the startup, sequence loading, and functional performance of the load groups is performed where practical. In those cases where it is not practical to perform complete functional performance testing, an evaluation is used to supplement the testing.

Reg. Guide 1.42 – Withdrawn

Reg. Guide 1.43, Rev. 0, 5/73 – Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
General		Conforms	The guidelines of this regulatory guide are followed during the welding process used for cladding ferritic steel components of the AP1000 with austenitic stainless steel. No qualifications are provided for by this regulatory guide for ASME SA-533 material and equivalent chemistry for forging grade ASME SA-508, Class 3, material. The reactor vessel, steam generator channel heads, accumulators, and core makeup tanks design specification restricts the low alloy steel forging material to ASME SA-508, Class 3, which is made to a fine grain practice only. Cladding of ASME SA-508, Class 2 is not applicable to the AP1000 design. The fabricator monitors and records the weld parameters to verify agreement with the parameters established by the procedure qualification as stated in Regulatory Position C.3.
C.1-3		N/A	The AP1000 material, specifically ASME SA-533 and SA-508 Class 3 made to a fine grain practice, is not subjected to the controls in this regulatory guide.

Reg. Guide 1.44, Rev. 0, 5/73 – Control of the Use of Sensitized Stainless Steel

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.1-6		Conforms	

Reg. Guide 1.45, Rev. 0, 5/73 – Reactor Coolant Pressure Boundary Leakage Detection Systems

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.1		Conforms	
C.2		Conforms	
C.3		Exception	The AP1000 reactor coolant pressure boundary leakage detection methods are selected and designed in accordance with the guidelines of this regulatory guide.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			No credit is taken for airborne particulate radiation measurement in quantifying the leak rate.
C.4		Conforms	
C.5		Conforms	
C.6		Exception	Airborne particulate radioactivity monitoring is not used to determine reactor coolant pressure boundary leakage.
C.7		Conforms	
C.8		Conforms	
C.9		Conforms	

Reg. Guide 1.46 – Withdrawn

Reg. Guide 1.47, Rev. 0, 5/73 – Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
General	IEEE Std. 279-1971, Section 4.13; and 10 CFR 50 App. B, Criterion XIV	Conforms	
C.1-4		Conforms	

Reg. Guide 1.48 – Withdrawn

Reg. Guide 1.49, Rev. 1, 12/73 – Power Levels of Nuclear Power Plants

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.1		Conforms	
C.2		Conforms	
C.3		Conforms	

Reg. Guide 1.50, Rev. 0, 5/73 – Control of Preheat Temperature for Welding of Low-Alloy Steel

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
General	ASME Code, Sections III and IX	N/A	The guidelines of this r egulatory guide are followed during the initial fabrication of low-alloy steel components of the AP1000. This regulatory guide is considered as applicable to ASME Code, Section III, Class 1 components. The AP1000 practice for Class 1 components is in agreement with the guidance of this regulatory guide

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			except for Regulatory Positions C.1(b) and 2. For AP1000 Class 2 and 3 components, the guidelines provided by this regulatory guide are not applied, however all requirements of the ASME Boiler and Pressure Vessel Code are imposed.
C.1(b)		Conforms	The welding procedures are qualified within the preheat temperature ranges required by ASME Code, Section IX. Experience has shown excellent quality of welds using the ASME qualification procedures.
C.2		Exception	The AP1000 position is that the guidance specified in this regulatory guide is both unnecessary and impractical. Code acceptable low-alloy steel welds have been and are being made under present procedures. It is not necessary to maintain the preheat temperature until a post-weld heat treatment has been performed in accordance with the guidance provided by this regulatory guide, in the case of large components. In some cases of reactor vessel main structural welds, the practice of maintaining preheat until the intermediate or final post-weld heat treatment has been followed. In other cases, an extended preheat practice has been utilized in accordance with the reactor vessel design specification. In this practice, the weld temperature is maintained at 400°F to 750°F for 4 hours after welding. The weld temperature may then be lowered to ambient without performing an intermediate or final pressurized water heat transfer at 1100°F. The welds have shown high integrity. Westinghouse practices are documented in WCAP-8577 (Reference 9) which has been accepted by the Nuclear Regulatory Commission.

Reg. Guide 1.51 – Withdrawn

Reg. Guide 1.52, Rev. 2, 3/78 – Design, Testing, and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Absorption Units of Light-Water-Cooled Nuclear Power Plants

General		N/A	There are no ESF atmosphere cleanup systems for the AP1000. The AP1000 does not require engineered safety feature atmosphere cleanup systems to meet limits on doses offsite or onsite.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.53, Rev. 0, 6/73 – Application of the Single-Failure Criterion to Nuclear Power Plant Protection Systems			
General	IEEE Std. 379-1972	Exception	Regulatory Guide 1.53 endorses IEEE Std. 379-72 (Reference 10), which has been superseded by IEEE Std. 379-2000 (Reference 11). The AP1000 uses the latest version of the industry standards (as of 4/2001). This version is not endorsed by a regulatory guide but its use should not result in deviation from the design philosophy otherwise stated in Regulatory Guide 1.53. IEEE Std. 379-2000 is endorsed by DG-1118 (Proposed Revision of Regulatory Guide 1.53). The guidelines are applicable to safety-related dc power systems. There are no safety-related ac power sources in the AP1000.
Reg. Guide 1.54, Rev. 1, 3/00 – Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants			
General	ASTM D 3843-00, ASTM D 3911-95, ASTM D 5144-00	Exception	Some coatings inside containment are nonsafety-related and satisfy appropriate ASTM Standards. See subsection 6.1.2 for additional information. Application is controlled by procedures using qualified personnel to provide a high quality product. The paint materials for nonsafety-related coatings inside the containment are subject to 10 CFR Part 50 Appendix B Quality Assurance requirements. The Combined License applicant is responsible for preparing the programs for safety related coatings and for procurement of nonsafety-related coatings inside containment. The degree of conformance with Reg. Guide 1.54 will be a function of the program developed by the Combined License applicant. See subsection 6.1.3 for the Combined License information item.
Reg. Guide 1.55 – Withdrawn			
Reg. Guide 1.56, Rev. 1, 7/78 – Maintenance of Water Purity in Boiling Water Reactors			
General		N/A	Applies to boiling water reactors only.
Reg. Guide 1.57, Rev. 0, 6/73 – Design Limits and Loading Combinations for Metal Primary Reactor Containment System Components			
General	ASME Code, Section III	Exception	The regulatory guide was issued in 1973. It refers to the ASME Code through the Summer 1973 Addenda. The acceptance criteria have been defined in greater detail in SRP 3.8.2. The AP1000 complies with the SRP

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			acceptance criteria with the exception that the operating basis earthquake is excluded.
Reg. Guide 1.58 – Withdrawn			
Reg. Guide 1.59, Rev. 2, 8/77 – Design Basis Floods for Nuclear Power Plants			
C.1-4	Regulatory Guide 1.29	N/A	The maximum water level due to the probable maximum flood is established as a site interface in Chapter 2 and is used in the design of the AP1000. This is the Combined License applicant's responsibility.
Reg. Guide 1.60, Rev. 1, 12/73 – Design Response Spectra for Seismic Design of Nuclear Power Plants			
C.1		Conforms	
C.2		Conforms	
Reg. Guide 1.61, Rev. 0, 10/73 – Damping Values for Seismic Design of Nuclear Power Plants			
General		Conforms	Damping values used in the AP1000 safe shutdown earthquake analyses are shown in Table 3.7.1-1. These values are based on Regulatory Guide 1.61, on the recommendations of ASCE 4-86 (Reference 12), and on values used and accepted on past projects (Reference 13). The values are conservative relative to realistic damping values reported in the literature (Reference 14). A site interface is established to verify that the site is within the range considered in the design.
Reg. Guide 1.62, Rev. 0, 10/73 – Manual Initiation of Protective Actions			
C.1		Conforms	
C.2		Conforms	
C.3		Conforms	
C.4		Conforms	
C.5		Conforms	
C.6	IEEE Std. 279-1971, Section 4.16	Conforms	

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.63, Rev. 3, 2/87 – Electric Penetration Assemblies in Containment Structures for Nuclear Power Plants			
General	IEEE Std. 317-1983 IEEE Std. 741-1986, Section 5.4	Exception	Regulatory Guide 1.63 endorses IEEE Std. 741-1986 (Reference 15), which has been superseded by IEEE Std. 741-1997 (Reference 16). The AP1000 uses the latest version of the industry standards (as of 4/2001). This version is not endorsed by a regulatory guide but its use should not result in deviation from the design philosophy otherwise stated in Regulatory Guide 1.63. Electric penetration assemblies are in conformance with IEEE Std. 317-1983 (Reference 17), Reference 16, and this regulatory guide with the clarification discussed below. The majority of low voltage control circuits are self-limiting in that circuit resistance limits the fault current to a level that does not damage the penetration. Where, on a case-by-case basis, a circuit is found not to be self-limiting, primary and backup breaker or fuse coordination or the addition of a subfeed over current protection as in the case of motor control centers, provide for safe operation. The energy levels in the instrument systems are such that damage cannot occur to the containment penetration.
Reg. Guide 1.64 – Withdrawn			
Reg. Guide 1.65, Rev. 0, 10/73 – Materials and Inspections for Reactor Vessel Closure Studs			
C.1.a	ASME Code, Section III, Subsection NB	Conforms	The reactor vessel closure stud bolting material is procured to a minimum yield strength of 130,000 psi and a minimum tensile strength of 145,000 psi. The material meets the criteria of Appendix G to 10 CFR 50. The reactor vessel design specification requires the maximum tensile strength of 170,000 psi for the closure stud material.
C.1.b		Conforms	
C.2	ASME Code, Section III, NB-2580	Conforms	The guidelines of this regulatory guide are followed during the fabrication of the stud bolts and nuts.
C.3		Conforms	The guidance of this regulatory guide is followed during the venting and filling of the AP1000 pressure vessel.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.4	ASME Code, Section XI; ASME Code, Section III, NB-2545 or NB-2546	Conforms	The guidelines of this regulatory guide are followed during the inservice examination of the AP1000 pressure vessel stud bolting.

Reg. Guide 1.66 – Withdrawn

Reg. Guide 1.67 – Withdrawn

Reg. Guide 1.68, Rev. 2, 8/78 – Initial Test Program for Water-Cooled Nuclear Power Plants

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.1	App. A.1.a	Conforms	Applies to AP1000 reactor coolant system components. (Pressurizer power-operated relief valves and reactor vessel internal vent valves are not design features of the AP1000. Jet pumps are applicable to boiling water reactors only.)
	App. A.1.b	Conforms	Applies to the AP1000 reactivity control system, except the systems for boiling water reactors such as rod worth minimizers. Standby liquid control system is not a design feature of the AP1000.
	App. A.1.c	Conforms	
	App. A.1.d	Conforms	The functions of these systems are replaced by the passive residual heat removal heat exchanger of the passive core cooling system. Reactor core isolation cooling system is not a design feature of the AP1000.
	App. A.1.e	Conforms	
	App. A.1.f	Conforms	
	App. A.1.g	Conforms	
	App. A.1.h	Conforms	The characteristics of the AP1000 passive safety systems allow the support systems such as the cooling water systems, the heating, ventilating, and air conditioning and the ac power sources to be nonsafety-related and simplified. The capability of these systems is established by testing. Cold water interlocks are not a design feature of the AP1000.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
	App. A.1.i	Conforms	The AP1000 has no secondary containment. Therefore, this guideline applies only to primary containment. The following systems or functions are not design features of the AP1000 and are therefore not tested: • Containment and containment annulus vacuum breaker • Containment supplementary leak collection • Standby gas treatment • Secondary containment system • Containment annulus and cleanup • Bypass leakage tests on pressure suppression • Ice condenser systems • Containment penetration cooling
	App. A.1.j	Conforms	Recirculation flow control, traversing incore probes, automatic dispatching control systems and hotwell level control are not design features of the AP1000.
	App. A.1.k	Conforms	
	App. A.1.l	Conforms	Condenser off gas systems are not a design feature of the AP1000.
	App. A.1.m	Conforms	
	App. A.1.n	Conforms	Seal water, boron recovery, shield cooling, refueling water storage tank heating, and equipment for establishing and maintaining subatmospheric pressures are not design features of the AP1000.
	App. A.1.o	Conforms	
	App. A.2	Conforms	As applicable for pressurized water reactor.
	App. A.3	Conforms	As applicable for pressurized water reactor.
	App. A.4	Conforms	As applicable for pressurized water reactor. Compliance with A.4.t is met for the AP1000 with the provisions to perform the pre-operational tests of the passive RHR heat exchanger, as well as the low power tests described in DCD test abstracts 14.2.10.3.6, “Natural Circulation (First Plant Only)” and 14.2.10.3.7, “Passive Residual Heat Removal Heat Exchanger (First Plant Only).” Natural circulation testing of the reactor coolant system will be performed using the steam generators and the

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			PRHR for the first plant only, in conformance with the AP1000 position on TMI item I.G.1 as outlined in subsection 1.9.4.2.1.
	App. A.5	Conforms	
C.2 through C9		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
General	Appendix B	N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
General	Appendix C	N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.

Reg. Guide 1.68.1, Rev. 1, 1/77 – Preoperational and Initial Startup Testing of Feedwater and Condensate Systems for Boiling Water Reactor Power Plants

General		N/A	Applies to boiling water reactors only.

Reg. Guide 1.68.2, Rev. 1, 7/78 – Initial Test Program to Demonstrate Remote Shutdown Capability for Water Cooled Nuclear Power Plants

General		Conforms	

Reg. Guide 1.68.3, (Task RS 709-4), 4/82 – Preoperational Testing of Instrument and Control Air Systems

General	Regulatory Guide 1.68	Conforms	

Reg. Guide 1.69, Rev. 0, 12/73 – Concrete Radiation Shields for Nuclear Power Plants

General	ANSI N101.6-1972	Exception	Regulatory Guide 1.69 endorses ANSI N101.6-1972 (Reference 18), which has been superseded by ANSI/ANS 6.4 1997 (Reference 19) and ACI 349-R01 (Reference 44). The AP1000 uses the latest version of the industry standards (as of 4/2001). This version is not endorsed by a regulatory guide but its use should not result in deviation from the design philosophy otherwise stated in Regulatory Guide 1.69.

Reg. Guide 1.70, Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants (LWR Edition), Rev. 3, 11/78

General		Conforms	

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.71, Rev. 0, 12/73 – Welder Qualification for Areas of Limited Accessibility			
General		Exception	Current practice does not require qualification or requalification of welders for areas of limited accessibility as described by this regulatory guide. The performance of required nondestructive evaluations helps to confirm weld quality. Limited accessibility qualification or requalification in excess of ASME Code, Section III or IX requirements is considered an unduly restrictive requirement for component fabrication, where the welders' physical position relative to the welds is controlled and does not present significant problems. In addition, shop welds of limited accessibility are repetitive due to multiple production of similar components, and such welding is closely supervised. For field application, the type of qualification is considered on a case-by-case basis due to the great variety of circumstances encountered.
Reg. Guide 1.72, Rev. 2, 11/78 – Spray Pond Piping Made From Fiberglass-Reinforced Thermosetting Resin			
General	ASME Code CCN-155-1 (1792-1)	N/A	The AP1000 does not have safety-related spray pond piping components. Therefore, this regulatory guide is not applicable to the AP1000.
Reg. Guide 1.73, Rev. 0, 1/74 – Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants			
General	IEEE Std. 382-1972	Exception	Qualification of valve appurtenances, such as motor operators, solenoid valves, and limit switches, is in accordance with this regulatory guide. For safety-related motor-operated valves located inside containment, environmental qualification is performed in accordance with IEEE Standards 382-1996 (Reference 21) and 323-1974 (Reference 22).
C.1-6		Conforms	
Reg. Guide 1.74 – Withdrawn			
Reg. Guide 1.75, Rev. 2, 9/78 – Physical Independence of Electric Systems			
General	IEEE Std. 384-1974	Exception	Regulatory Guide 1.75 endorses IEEE Std. 384-74 (Reference 23) which has been superseded by a later revision, IEEE Std. 384-81 (Reference 24). It is the later version that is used for the referenced purposes. This version has not yet been endorsed by a regulatory

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			guide. The differences between the two revisions are not expected to contribute to conflicting design configurations because the jurisdiction of Regulatory Guide 1.75 with regard to the onsite ac power sources is limited. Specifically, since the AP1000 does not use safety-related ac power sources, the guidelines of Regulatory Guide 1.75 are applicable on a very limited basis to provide guidance on the Class 1E/non-Class 1E electrical separation and isolation for the following ac components that employ safety-related and nonsafety-related circuits: a) Class 1E dc battery chargers b) Reactor coolant pump switchgear c) Class 1E dc and UPS system regulating transformers. See subsection 8.3.2.4.2 for exceptions related to spacial separation between separation groups. Two fuses in series may be used as an isolation device for Class 1E and non-Class 1E isolation.

Reg. Guide 1.76, Rev. 0, 4/74 – Design Basis Tornado for Nuclear Power Plants

C.1		Exception	The design basis tornado for the AP1000 is defined by the following parameters: Maximum wind speed: 300 mph Maximum rotational speed: 240 mph Translational speed: 60 mph (maximum) 5 mph (minimum) Radius to maximum wind from center of tornado: 150 feet Atmospheric pressure drop: 2.0 psi Rate of pressure drop: 1.2 psi/sec. Chapter 2 provides design basis tornado interface parameters.
C.2		Conforms	

Reg. Guide 1.77, Rev. 0, 5/74 – Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors

General		Exception	The guidance of Reg. Guide 1.183, "Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors" will be followed instead of Reg. Guide 1.77.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.78, Rev. 1, 12/01 – Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release			
C.1		N/A	This criterion is site-specific. Therefore, this is not applicable to AP1000 design certification. It is the Combined License applicant's responsibility.
C.2		N/A	This criterion is site-specific. Therefore, this is not applicable to AP1000 design certification. It is the Combined License applicant's responsibility.
C.3.1		N/A	This criterion is site-specific. Therefore, this is not applicable to AP1000 design certification. It is the Combined License applicant's responsibility.
C.3.2		Conforms	
C.3.3		Exception	For AP1000 design certification, the atmospheric dispersion factors are not calculated (since there are no specific site data), but are selected so as to bound the majority of existing sites. Section 2.3 provides additional information.
C.3.4		Conforms	
C.4.1		N/A	This criterion is site-specific. Therefore, this is not applicable to AP1000 design certification. It is the Combined License applicant's responsibility.
C.4.2		Conforms	
C.4.3		Conforms	
C.5		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
Reg. Guide 1.79, Rev. 1, 9/75 – Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors			
General		Conforms	Preoperational testing is performed to test the functioning of the accumulators, core makeup tanks, passive residual heat removal heat exchanger, and automatic depressurization system, in a manner consistent with this regulatory guide. However, the AP1000 does not have high-head or low-head active safety-injection pumps. Therefore, many of the specific guidelines of this regulatory guide do not apply.
Reg. Guide 1.80 – Withdrawn			

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.81, Rev. 1, 1/75 – Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plant			
General		N/A	The AP1000 is a single unit plant. Therefore, this is not applicable to the AP1000.
Reg. Guide 1.82, Rev. 2, 5/96 – Water Sources for Long Term Recirculation Cooling Following a Loss-of-Coolant Accident			
General		Conforms	The AP1000 does not have high-head or low-head safety-injection pumps that need to take suction from the containment. The AP1000 does have a gravity-driven recirculation path that employs a containment recirculation arrangement. This containment recirculation can also be used to feed the normal residual heat removal pumps if they are available. The containment recirculation design conforms with the guidelines of this regulatory guide.
Reg. Guide 1.83, Rev. 1, 7/75 – Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes			
General		Conforms	A program for in-service inspection of AP1000 steam generator tubing is established and performed in accordance with the guidelines of this regulatory guide. The baseline inspection will be performed in accordance with Regulatory Position C.3.a. Should the Combined License applicant request a baseline examination at the manufacturing facility, it will be performed in accordance with Regulatory Position C.3.a.
C.1		Conforms	
C.2		Exception	The specification of equipment in Regulatory Position C.2.c does not represent state-of-the-art equipment for gathering and storing eddy current information. When an eddy current inspection of an AP1000 steam generator is done in the manufacturing facility, more capable equipment than that specified in the regulatory guide is used. The steam generator design is compatible with robotic eddy current inspection equipment.
C.3		Exception	As noted in the comment on Criteria Section C.2, any eddy current inspection done in the manufacturing facility uses equipment of more current technology than that specified in Criteria Section C.2.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.4-7		Conforms	
C.8		Exception	The only corrective action recognized by the regulatory guide is plugging of the tube to remove it from service. Sleeving of tubes is in many cases an acceptable repair method. The AP1000 steam generator design provides increased access to tubes to implement the sleeving repair method or other repair methods which may be developed.
Reg. Guide 1.84, Rev. 31, 5/99 – Design and Fabrication Code Case Acceptability ASME Section III Division 1			
General		Conforms	The ASME Code Cases required for design certification are listed in Table 5.2-3. These cases are included in Regulatory Guide 1.84 or have been accepted by the US Nuclear Regulatory Commission staff as part of the review of AP1000.
C.1	ASME Code, Section III, Code Cases	Conforms	As applicable for pressurized water reactor.
C.2-5		Conforms	
Reg. Guide 1.85, Rev. 31, 5/99 – Materials Code Case Acceptability - ASME Code, Section III, Division 1			
General		Conforms	Refer to the discussion on Regulatory Guide 1.84.
C.1	ASME Code, Section III, Code Cases	Conforms	As applicable for pressurized water reactor.
C.2-5		Conforms	
Reg. Guide 1.86, Rev. 0, 6/74 – Termination of Operating Licenses for Nuclear Reactors			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
Reg. Guide 1.87, Rev. 1, 6/75 – Guidance for Construction of Class 1 Components in Elevated Temperature Reactors			
General		N/A	The AP1000 is not an elevated temperature reactor. See Section 1.2 for a general description of the plant and plant parameters. This regulatory guide is not applicable to the AP1000.
Reg. Guide 1.88 – Withdrawn			

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.89, (Task EE 042-2), Rev. 1, 6/84 – Environmental Qualification of Certain Electric Equipment Important to Safety For Nuclear Power Plants			
General	IEEE Std. 323-1974	Conforms	Conformance of AP1000 Class 1E equipment with 10 CFR 50.49, Reference 26 and this regulatory guide is demonstrated by an appropriate combination of the following: type testing, operating experience, qualification by analysis and ongoing qualification.
C.1	App. A	Conforms	As applicable for pressurized water reactor.
	App. B	Conforms	As applicable for pressurized water reactor.
	Regulatory Guide 1.97	Conforms	As applicable for pressurized water reactor.
C.2		Conforms	
C.2.a	App. C	Conforms	As applicable for pressurized water reactor.
C.2.b		Conforms	
C.2.c	App. D	Conforms	
C.2.c.1		Exception	Source term definition is discussed in the exceptions to Regulatory Guide 1.4, Positions C.1.a and C.1.b.
C.2.c.2		Exception	The fission product inventories in the fuel are discussed in the exception to Regulatory Guide 1.25, Position C.1.d.
C.2.c.3-8		Conforms	
C.2.d		Conforms	
C.3-6		Conforms	
C.7	App. E	Conforms	
Reg. Guide 1.90, Rev. 1, 8/77 – Inservice Inspection of Prestressed Concrete Containment Structures with Grouted Tendons			
General		N/A	The AP1000 does not have a concrete containment and does not use a prestressing tendon in the containment structures. Therefore, this regulatory guide is not applicable to the AP1000.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.91, Rev. 1, 2/78 – Evaluation of Explosions Postulated to Occur on Transportation Routes Near Nuclear Power Plant Sites			
General		N/A	Onsite explosive materials conform to these guidelines. Offsite explosive materials are site-specific and are the Combined License applicant's responsibility. See subsection 2.2.1 for Combined License information for identification of site-specific potential hazards.
Reg. Guide 1.92, Rev. 1, 2/76 – Combining Modal Responses and Spatial Components in Seismic Response Analysis			
C.1		Conforms	
C.2		Conforms	
C.3		Conforms	
Reg. Guide 1.93, Rev. 0, 12/74 – Availability of Electric Power Sources			
C.1-2		N/A	The ac power sources are nonsafety-related. Therefore, these guidelines do not apply to the AP1000.
C.3		N/A	The function of the nonsafety-related diesel-generators for the AP1000 is to provide ac power for equipment and lighting during loss of offsite power but is not required for safe shutdown. Therefore, these guidelines do not apply to the AP1000.
C.4		N/A	See discussion on Criteria Section C.3.
C.5		Exception	AP1000 does not follow the guidance of C.5 for a 2-hour completion time for the limiting conditions of operation associated with the loss of one dc power subsystem. If one of the Class 1E dc electrical power subsystems is inoperable, the remaining Class 1E dc electrical power subsystems have the capacity to support a safe shutdown and to mitigate all design basis accidents, based on conservative analysis. Because of the passive system design and the use of fail-safe components, the remaining Class 1E dc electrical power subsystems have the capacity to support a safe shutdown and to mitigate most design basis accidents following a subsequent worst-case single failure. Also, with passive/fail-safe design, the risk associated with the loss of one Class 1E dc subsystem is similar to the loss of one ac supply for a conventional unit.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			AP1000 uses a 72-hour completion time for the limiting conditions of operation associated with the loss of one dc power subsystem to be consistent with the guidance in C.1 for a conventional plant with the loss of one ac source. The 72-hour completion time is reasonable based on engineering judgement balancing the risks of operation without one dc subsystem against the risks of a forced shutdown. Additionally, the completion time reflects a reasonable time to assess plant status; attempt to repair or replace, thus avoiding an unnecessary shutdown, and if necessary, prepare and effect an orderly and safe shutdown.

Reg. Guide 1.94, Rev. 1, 4/76 – Quality Assurance Requirements for Installation, Inspection and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants

General	ANSI N45.2.5-1974	N/A	Not applicable to AP1000 design certification. This is the responsibility of the Combined License applicant. See Section 17.5 for the Combined License information item.

Reg. Guide 1.95 – Withdrawn

Reg. Guide 1.96, Rev. 1, 6/76 – Design of Main Steam Isolation Valve Leakage Control Systems for Boiling Water Reactor Nuclear Power Plants

General		N/A	Applies to boiling water reactors only.

Reg. Guide 1.97, Rev. 3, 5/83 – Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident

General	ANS-4.5-1980	Conforms	The variables to be monitored are selected according to usage and need in the plant Emergency Response Guidelines. They are assigned design and qualification Category 1, 2, or 3 and classified as Type A, B, C, D, or E. Due to AP1000 specific design features, the selection of some plant-specific variables and their classifications and categories are different from those of this regulatory guide. For example, the use of the passive residual heat removal system as the safety grade heat sink allows steam generator wide range level to be category 2, not category 1 as specified in Regulatory Guide 1.97. The AP1000 has no Type A variables. See Section 7.5 for additional information. Since Category 3 instrumentation is not part of a safety-related system, it is not qualified to provide information

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			when exposed to a post-accident adverse environment. Category 3 instrumentation is subject to servicing, testing, and calibration programs that are specified to maintain their capability. However, these programs are not in accordance with Regulatory Guide 1.118, which applies to safety-related systems.
C.1-2		Conforms	

Reg. Guide 1.98, Rev. 0, 3/76 – Assumptions Used for Evaluating the Potential Radiological Consequences of a Radioactive Offgas System Failure in a Boiling Water Reactor

General		N/A	Applies to boiling water reactors only.

Reg. Guide 1.99, (Task ME 305-4), Rev. 2, 5/88 – Radiation Embrittlement of Reactor Vessel Materials

C.1		Conforms	
C.2		Conforms	
C.3		Conforms	

Reg. Guide 1.100, (Task EE 108-5), Rev. 2, 6/88 – Seismic Qualification of Electric and Mechanical Equipment for Nuclear Power Plants

General	IEEE Std. 344-1987	Conforms	

Reg. Guide 1.101, Rev. 3, 8/92 – Emergency Planning and Preparedness for Nuclear Power Reactors

General	NUREG-0654, FEMA-REP-1 NUMARC/NESP-007	Conforms	Emergency planning is the responsibility of the Combined License applicant. See Section 13.3 for the Combined License information on emergency planning. RG 1.101 (Revision 2) references NUREG-0654/ FEMA-REP-1 and item II.H, "Emergency Facilities and Equipment" of NUREG-0654/FEMA-REP-1 is applicable to the technical support center (TSC), operations support center (OSC), and the emergency operations facility (EOF) in the AP1000 design. Designing the EOF, including specification of its location, in accordance with the AP1000 human factors engineering program is the responsibility of the Combined License applicant. See section 18.2.6 for the Combined License information on designing the EOF. The AP1000 design conforms with the design criteria of item II.H that pertain to the TSC and the OSC.

Reg. Guide 1.102, Rev. 1, 9/76 – Flood Protection for Nuclear Power Plants

C.1		Conforms	

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.2	Regulatory Guide 1.59, C.2	Conforms	
C.3		Conforms	

Reg. Guide 1.103 – Withdrawn

Reg. Guide 1.104 – Withdrawn

Reg. Guide 1.105, Rev. 3, 12/99 – Instrument Setpoints for Safety-Related Systems

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
General	ISA-S67.04-1994	Conforms	The technical specifications setpoints provide the margin from the nominal setpoint to the safety-analysis limit to account for drift when measured at the rack during periodic testing. The allowances between the technical specification limit and the safety limit include the following items: a) the inaccuracy of the instrument; b) process measurement accuracy; c) uncertainties in the calibration; and d) environmental effects on equipment accuracy caused by postulated or limiting postulated events (only for those systems required to mitigate consequences of an accident). The setpoints are chosen such that the accuracy of the instrument is adequate to meet the assumptions of the safety analysis. The instrumentation range is based on the span necessary for the associated function. Narrow range instruments are used where necessary. Instruments are selected based on expected environmental and accident conditions. The need for qualification testing is evaluated and justified on a channel-by-channel basis. Administrative procedures coupled with the present cabinet alarms and/or locks provide sufficient control over the setpoint adjustment mechanism such that no integral setpoint securing device is required. Integral setpoint locking devices are not supplied. A plant-specific setpoint analysis must be performed to provide technical specification setpoints prior to plant startup. AP1000 conforms to the documentation requirements of the 1994 criteria.

Reg. Guide 1.106, Rev. 1, 3/77 – Thermal Overload Protection for Electric Motors on Motor-Operated Valves

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.1	IEEE 279-1971, Sections 4.1, 4.2, 4.3, 4.4, 4.5, 4.10, and 4.13	Exception	Regulatory Guide 1.106 endorses IEEE Std. 279-1971 Reference 27, which has been replaced by IEEE STD 603-1991, (Reference 51). The AP1000 uses IEEE Std. 603-1991. This standard is endorsed by Regulatory Guide 1.153.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			The only safety-related electric motor-operated valves are dc.
C.2		Conforms	

Reg. Guide 1.107, Rev. 1, 2/77 – Qualifications for Cement Grouting for Prestressing Tendons in Containment Structures

General		N/A	The AP1000 does not have a concrete containment and does not use a prestressing tendon in the containment structure. Therefore, these guidelines are not applicable to the AP1000.

Reg. Guide 1.108 – Withdrawn

Reg. Guide 1.109, Rev. 1, 10/77 – Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I

General		Conforms	This is applicable to the evaluation of specific sites. AP1000 design certification application evaluates how the AP1000 design is expected to compare with existing plants. This comparison is made based on the calculation of anticipated annual releases for the AP1000.

Reg. Guide 1.110, Rev. 0, 3/76 – Cost-Benefit Analysis for Radwaste Systems for Light-Water-Cooled Nuclear Power Reactors

General	10 CFR 50, App. I, Section II.D	Exception	The disposal of effluents for the AP1000 is within the limits of Appendix I of 10 CFR 50, and the radwaste treatment systems have sufficient capacity to control effluents. The AP1000 approach to the design of radwaste systems is the result of a nuclear industry-sponsored program to optimize the radwaste systems design. A site-specific cost-benefit analysis is not required for sites that meet the site interface criteria.

Reg. Guide 1.111, Rev. 1, 7/77 – Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors

General		N/A	This is applicable to the evaluation of specific sites. Interface data are provided. This is the Combined License applicant's responsibility.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.112, Rev. O-R, 5/77 – Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light-Water-Cooled Power Reactors			
C.1	10 CFR 20.1(c); 10 CFR 50.34a; 10 CFR 50.36a; 10 CFR 50, App. I	Exception	The reference to 10 CFR 20.1(c) is no longer valid in the current version of 10 CFR Part 20.
C.2	NUREG-0016; NUREG-0017	Exception	Revision 1 of NUREG-0017 is used.
C.3		Conforms	
Reg. Guide 1.113, Rev. 1, 4/77 – Estimating Aquatic Dispersion of Effluents from Accidental and Routine Reactor Releases for the Purpose of Implementing Appendix I			
General		N/A	This is applicable to the evaluation of specific sites. Interface data are provided. This is the Combined License applicant's responsibility.
Reg. Guide 1.114, Rev. 2, 5/89 – Guidance to Operators at the Controls and to Senior Operators in the Control Room of a Nuclear Power Unit			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility. See Section 13.2 for the Combined License information item on training and Section 13.5 for the Combined License information item on procedures.
Reg. Guide 1.115, Rev. 1, 1/77 – Protection Against Low-Trajectory Turbine Missiles			
General		Conforms	The SRP 3.5.1.3 issued in 1981 and Regulatory Guide 1.115, issued in 1977, provide criteria for protection against the effects of potential turbine missiles. Reference 28 issued in 1984 states that "the Nuclear Regulatory Commission staff has shifted emphasis in the reviews of the turbine missile issue from the strike and damage probability (P_2xP_3) to the missile generation probability (P_1) and, in the process, has attempted to integrate the various aspects of the issue into a single coherent evaluation." The AP1000 turbine is arranged in a radial orientation. The two low pressure turbines incorporate fully integral rotors. The turbine conforms with the criteria given in References 28 and WCAP-15783 (Reference 29).

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.116, Rev. O-R, 5/77 – Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems			
General	ANSI N45.2.8-1975	N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility. See Section 17.5 for the Combined License information item.
Reg. Guide 1.117, Rev. 1, 4/78 – Tornado Design Classification			
C.1		Conforms	
C.2		Conforms	
C.3		Conforms	
APPENDIX			
General		Conforms	For the AP1000, the leaktight integrity of the primary containment is maintained.
Reg. Guide 1.118, Rev. 3, 4/95 – Periodic Testing of Electric Power and Protection Systems			
General	IEEE Std. 338-1987	Conforms	Guidelines apply to safety-related dc power systems. Since the AP1000 has no safety-related ac power sources, the guidelines do not apply to the AP1000 ac power sources.
Reg. Guide 1.119 – Withdrawn			
Reg. Guide 1.120, Rev. 1, 11/77 – Fire Protection Guidelines for Nuclear Power Plants			
General		Exception	The AP1000 design conforms with the Branch Technical Position CMEB 9.5.1 (Reference 32), which is attached to Section 9.5.1 of the Standard Review Plan, NUREG-0800 (Reference 33), as described in Section 9.5.1. Therefore, these guidelines are not applicable to the AP1000.
Reg. Guide 1.121, Rev. 0, 8/76 – Bases for Plugging Degraded Pressurizer Water Reactor Steam Generator Tubes			
General		Conforms	The only corrective action recognized by this regulatory guide is plugging of the tube to remove it from service. Sleeving of tubes is in many cases an acceptable repair method. The AP1000 steam generator design provides increased access to tubes to implement the sleeving repair method or other repair methods which may be developed.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.1		Exception	Westinghouse interprets the term "unacceptable defects" to apply to those imperfections resulting from service induced mechanical or corrosion degradation of the tube walls which have penetrated to a depth or a length or a combination of both in excess of the plugging limit.
C.2.a.(1)		Exception	Westinghouse interprets this criterion to exclude the local region of the crack tip for Inconel tubing.
C.2.a.(2)		Exception	Tube minimum wall requirements are calculated in accordance with the following criteria. For normal plant operation, allowable membrane stress, Pm, is limited to a margin of three against exceeding the ultimate tensile strength of the material. As this regulatory guide constitutes an operating criterion, the allowable stress limits are based on expected lower bound material properties rather than ASME Code minimum values. Expected strength properties are obtained from statistical analysis of tensile test data of actual production tubing.
C.2.a(3)		Conforms	
C.2.a(4)		Exception	Refer to the discussion on Criteria Section C.2.a(2).
C.2.a.(5)-(6)		Conforms	
C.2..b.		Exception	In cases where sufficient inspection data exist to establish degradation allowance, the rate used is an average time-rate determined from the mean of the test data. Where requirements for minimum wall are markedly different for various areas of the tube bundle, such as the U-bend area versus straight length in Westinghouse designs, separate plugging limits are established to address the varying requirements in a manner which does not require unnecessary plugging of tubes.
C.3.a - c		Conforms	
C.3.d.(1)-(3)		Conforms	
C.3.e.(1)-(5)		Conforms	
C.3.e.(6)		Exception	Computer code names and references are supplied rather than actual codes.
C.3.e.(7)-(10)		Conforms	
C.3.f.(1)-(3)		Conforms	

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.122, Rev. 1, 2/78 – Development of Floor Design Response Spectra for Seismic Design of Floor-Supported Equipment or Components			
C.1-3		Conforms	
Reg. Guide 1.123 – Withdrawn			
Reg. Guide 1.124, Rev. 1, 1/78 – Service Limits and Loading Combinations for Class 1 Linear-Type Component Supports			
General	ASME Code, Section III Subsection NF	Conforms	Many of the items addressed in this regulatory guide have since been incorporated into later ASME Code, Section III Editions and Addenda. The design conforms to this regulatory guide with the following interpretations to maintain consistency with the ASME Code: 1. References to ASME Code, Section III, Subsection NF and Appendix XVII paragraphs are interpreted to be references to the corresponding paragraph in Subsection NF of the ASME Code. 2. References to ASME Code Case 1644 are interpreted to be references to the accepted versions of ASME Code Cases N-249 and N-71.
C.1		Conforms	
C.2	Code Case 1644	Conforms	Values of Su at these elevated temperatures are determined by test rather than via the method 2 as given by this regulatory position.
C.3	ASME Code, Section III, Appendix XVII	Conforms	
C.4	ASME Code, Section III, Appendix XVII-2110(b)	Exception	Paragraph B.1(b) of this regulatory guide states that "Allowable service limits for bolted connections are derived from tensile and shear stress limits and their nonlinear interaction. They also change with the size of the bolt. For this reason, the increases permitted by ASME Code, Section III, Subsections NF-3231.1, XVII-2110(a), and F-1370(a) are not directly applicable to allowable shear stresses and allowable stresses for bolts and bolted connections." This regulatory position also states that "This increase of level A or B service limits does not apply to limits for bolted connections and shear stresses."

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			As stated above, the increase in bolt allowable stress under emergency and faulted conditions is not permitted because the interaction between the allowable tension and shear stress in bolts is nonlinear, and the allowable tension and shear stress vary with the bolt size. The ASME Code, NF-3225, allows small increases in allowable stresses for Level B, Level C (previously termed "emergency"), Level D (previously termed "faulted"), and test conditions. The ASME Code rules are adequate since they satisfy the two objectives raised in the above quoted paragraph and will be used without further restrictions or justifications. This position is based on the following. 1. The interaction curve between the shear and tension stress in bolts is more closely represented by an ellipse and not a line. 2. The ASME Code specifies stress limits for bolts and represents this tension/shear relationship as a non-linear interaction equation (ellipse). This interaction equation has a built-in safety factor that ranges between two and three (depending on whether the bolt load is predominately tension or shear) based on the actual strength of the bolt as determined by test. See Reference 34. 3. This regulatory position states that "Any increases of limits for shear stresses above 1.5 times the ASME Code, Level A service limits should be justified." Concerning allowable shear stresses, the AP1000 uses the ASME Code, Subsection NF requirements. The ASME Code shear stress limits (NF-3300 and Tables NF-3523.2 and NF-3623.2-1) generally meet the guidance provided by this regulatory position that shear stresses be maintained within 1.5 times Level A service limits. This limit may be exceeded slightly in some limited cases such as Level D limits for SA-36 material, in which case the NF shear stress limit of .42 Su is 13 percent greater than this regulatory guide limit of 1.5 x .4 Fy. Su and Fy are the material tensile and yield strengths, respectively.
C.5.a	ASME Code, Section III,	Exception	The AP1000 evaluates supports to current Level B stress limits for the upset load combination. Effects of constraint of free-end displacements are included in the upset loading condition while no further increase in allowable stresses over and above the Level B limits is

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			permitted. The operating basis earthquake has been eliminated from the AP1000 design basis.
C.5.b-c	ASME Code, Section III, Subsection NF-3262.3, Appendix XVII-4200, Appendix XVII-4110(a)	Conforms	The operating basis earthquake has been eliminated from the AP1000 design basis.
C.6	ASME Code, Section III, Appendix XVII-2000, 2110(a) Subsection NF 2362.3, Appendix XVII-4200, 4110(a), II-1400	Conforms	
C.7.a	ASME Code, Section III, Appendix XVII-2000, and F-1370(a)	Conforms	
C.7.b		Exception	The AP1000 uses the provisions of the ASME Code, Section III, Appendix F to determine faulted condition allowable loads for supports designed by the load rating method. The method described in this regulatory position is conservative and inconsistent with the remainder of the faulted stress limits.
C.7.c	ASME Code, Section III Appendix XVII-4200, and F-1370(b)	Conforms	
C.7.d	ASME Code, Section III, II-1400, and F-1370(b)	Conforms	
C.8		Exception	The reduction of allowable stresses to no greater than Level B limits (which in reality are only design limits since design, Level A and Level B limits are the same for linear supports) for support structures in those systems with normal safety-related functions occurring during emergency or faulted plant conditions is overly conservative for components which are not required to mechanically function (inactive components). For service Level C and D loading conditions, Level C limits are used for the support of active components.

Reg. Guide 1.125, Rev. 1, 10/78 – Physical Models for Design and Operation of Hydraulic Structures and Systems for Nuclear Power Plants

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
General		Conforms	
C.1-6		Conforms	

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.126, Rev. 1, 3/78 – An Acceptable Model and Related Statistical Methods for the Analysis of Fuel Densification			
C.1-2		Exception	Westinghouse uses the densification model described in the Nuclear Regulatory Commission-approved topical reports WCAP-10851-A and WCAP-13589-A. Westinghouse conforms to the methodology of this regulatory guide when implementation of the methodology is required.
C.3-4		Conforms	
C.5		Conforms	
Reg. Guide 1.127, Rev. 1, 3/78 – Inspection of Water-Control Structures Associated With Nuclear Power Plants			
General		N/A	The AP1000 does not have water-control structures. Therefore, this guideline is not applicable to the AP1000. See Subsection 2.5.6 for the Combined License information item for embankments and dams.
Reg. Guide 1.128, Rev. 1, 10/78 – Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants			
General	IEEE Std. 484-1975	Exception	Regulatory Guide 1.128 endorses IEEE Std. 484-75 (Reference 36) which has been superseded by IEEE Std. 484-1996 (Reference 37). The AP1000 uses the latest version of the industry standards (as of 4/2001). This version is not endorsed by a regulatory guide but its use should not result in deviation from the design philosophy otherwise stated in Regulatory Guide 1.128.
Reg. Guide 1.129, Rev. 1, 2/78 – Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Nuclear Power Plants			
General	IEEE Std. 450-1975	N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
Reg. Guide 1.130, Rev. 1, 10/78 – Service Limits and Loading Combinations for Class 1 Plate-And-Shell-Type Component Supports			
General	ASME Code, Section III Subsection NF	Exception	Many of the items addressed in this regulatory guide have since been incorporated into later ASME Code, Section III, Editions and Addenda. The plant design conforms to this regulatory guide with the following

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			interpretations to maintain consistency with the ASME Code: 1. Regulatory guide references to ASME Code, Section III, Subsection NF and Appendix XVII paragraphs are interpreted to be references to the corresponding paragraph in the ASME Code, Subsection NF. 2. Regulatory guide references to ASME Code Case 1644 are interpreted to be references to the latest acceptable versions of the ASME Code Case N-249 and N-71. Paragraph B.1 of this regulatory guide states that "Allowable stress limits for bolted connections are derived on a different basis that varies with the size of the bolt. For this reason, the increases permitted by NF-3222.3 and F-1323.1(a) of ASME Code, Section III are not directly applicable to bolts and bolted connections." The ASME Code rules are adequate for bolt design and uses the rules without further restriction and justification. The maximum stress increase factor allowed is 25 percent for the Service Level D condition, and the stress allowables do not vary with bolt size. The AP1000 takes exception to the guideline stated in Paragraph B.5 of this regulatory guide, that systems whose safety-related function occurs during emergency or faulted plant conditions should meet Level A limits. The reduction of allowable stresses to no greater than Level A limits for support structures in those systems with normal safety-related functions occurring during emergency or faulted plant conditions is overly conservative for components which are not required to mechanically function (inactive components). For service, Level C and D loading conditions, Level C limits are used for the support of active components.
C.1		Conforms	
C.2	Code Case 1644	Conforms	

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.3		Exception	Design margins of two for flat plates and three for shells are unnecessarily restrictive for normal, upset, and emergency conditions, as well as inconsistent with ASME Code requirements. For these loading conditions, the AP1000 limits the allowable buckling strength to 2/3 of the critical buckling strength.
C.4	ASME Code, Section III, NF-3221.1, NF-3221.2, NF-3222, NF-3262.2, II-1400	Exception	This regulatory position recommends that design stress limits be used in conjunction with a loading combination that includes operating basis earthquake. The ASME Code rules (in which Level B stress limits are typically used for the upset load combination) provide a conservative design basis. The AP1000 uses the latest rules (as of 4/2001) without further restriction or justification. The operating basis earthquake has been eliminated from the AP1000 design basis. Refer also to the discussion on Criteria Section C.3.
C.5.a	ASME Code, Section III, NF-3224	Exception	Refer to the discussion on Criteria Section C.3.
C.5.b-c	ASME Code, Section III, NF-3262.2, II-1400	Conforms	
C.6.a	ASME Code, Section III, F-1323.1(a), F-1370(c)	Conforms	
C.6.b	ASME Code, Section III, NF-3262.1	Exception	The limit based on the test load given in this regulatory position is overly conservative and is inconsistent with ASME Code requirements. The AP1000 uses the provisions of the ASME Code, Section III, Appendix F to determine faulted condition allowable loads for supports designed by the load rating method.
C.6.c		Conforms	
C.6.d	ASME Code Section III, F-1324, F-1370(c)	Conforms	
C.7		Conforms	

Reg. Guide 1.131, Rev. 0, 8/77 – Qualification Tests of Electric Cables, Field Splices and Connections for Light-Water-Cooled Nuclear Power Plants

General	IEEE Std. 383-1974	Conforms	The insulating and jacketing material for electrical cables are selected to meet the fire and flame test requirements of IEEE Standard 1202 or IEEE

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			Standard 383 excluding the option to use the alternate flame source, oil or burlap.
C.1-14		Conforms	

Reg. Guide 1.132, Rev. 1, 3/79 – Site Investigations for Foundations of Nuclear Power Plants

General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility. The AP1000 requirements for site investigations are outlined in Section 2.5.

Reg. Guide 1.133, Rev. 1, 5/81 – Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors

General		Conforms	A digital metal impact monitoring system (DMIMS) monitors the reactor coolant system for the presence of loose metallic parts. The system actuates audible and visual alarms if a signal exceeds the preset alarm level. The digital metal impact monitoring system is not a Class 1E system. It serves as a diagnostic aid to detect loose parts in the reactor coolant system before damage occurs. Database calibration is made prior to plant startup and the capability for periodic online channel checks and channel functional tests are incorporated in the digital metal impact monitoring system design.
C.1.a-i		Conforms	
C.2		Conforms	
C.3.a		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
C.3.b		Conforms	
C.4-5		Conforms	
C.6		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.

Reg. Guide 1.134, Rev. 3, 3/98 – Medical Evaluation of Nuclear Power Plant Personnel Requiring Operator Licenses

General		N/A	Not applicable to AP1000 plant design certification. This is the Combined License applicant's responsibility. See Section 13.5 for the Combined License information item for administrative procedures.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.135, Rev. 0, 9/77 – Normal Water Level and Discharge at Nuclear Power Plants			
General		Conforms	The normal ground and surface water levels and surface water discharges for the AP1000 are determined using the postulated site parameters. Chapter 2 provides additional information.
Reg. Guide 1.136, Rev. 2, 6/81 – Materials, Construction, and Testing of Concrete Containments			
General		N/A	The AP1000 does not have a concrete containment. Therefore, this guideline is not applicable to the AP1000.
Reg. Guide 1.137, Rev. 1, 10/79 – Fuel-Oil Systems for Standby Diesel Generators			
General		N/A	The AP1000 diesel-generators and the associated fuel-oil systems are nonsafety-related. Therefore, this guideline is not applicable to the AP1000.
Reg. Guide 1.138, Rev. 0, 4/78 – Laboratory Investigations of Soils for Engineering Analysis and Design of Nuclear Power Plants			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
Reg. Guide 1.139, Rev. 0, 5/78 – Guidance for Residual Heat Removal			
C.1.a		Exception	The AP1000 employs a full pressure/temperature passive residual heat removal heat exchanger that is automatically actuated. The heat exchanger does not rely on ac or dc power. Fail-safe valves are used to manually isolate the heat exchanger. When these valves are open, the reactor coolant pumps (if available) or natural circulation produces flow through the heat exchangers. The heat exchanger is safety-related, seismically designed, and can tolerate single active failure. Continued operation of the heat exchanger brings the reactor coolant system pressure and temperature down to the point where the stress in the reactor coolant system pressure boundary is low. This temperature is about 400°F which allows an reactor coolant system pressure of 1/10 of design (250 psia).
C.1.b		Conforms	
C.1.c		Exception	See the comment on Criteria Section C.1.a. The passive residual heat removal heat exchanger does not rely on pumps, ac power sources, air systems, or water cooling systems.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.2		Conforms	
C.3		Conforms	
C.4		N/A	The passive residual heat removal heat exchanger does not have pumps. Therefore, this guideline is not applicable to the AP1000.
C.5	IEEE Std. 338; Regulatory Guide 1.22; Regulatory Guide 1.68	Conforms	IEEE Std. 338-1987 (Reference 31) is current standard.
C.6		N/A	The passive residual heat removal heat exchanger provides this function. As a result, the auxiliary feedwater system has been replaced by a nonsafety-related startup feedwater system. Therefore, this guideline is not applicable to the AP1000.
C.7	Regulatory Guide 1.33	N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.

Reg. Guide 1.140, Rev. 2, 06/01 – Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Normal Atmosphere Cleanup System in Light-Water-Cooled Nuclear Power Plants

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.1		Conforms	Regulatory Guide 1.140 endorses ASME Standard N509-1989 (Reference 39), ASME Standard N510-1989 (Reference 40), and ASME AG-1-1997 (Reference 38). The AP1000 uses the latest version of the industry standards (as of 3/2002).
C.2.1-2.4		Conforms	
C.3.1-3.2		Conforms	
C.3.3	ERDA 76-21, Section 5.6; ASME N509-1989 Section 4.9	Conforms	
C.3.4	Regulatory Guide 8.8	Conforms	
C.3.5		Conforms	
C.3.6	ASME AG-1-1997 Article SA-4500	Exception	Exhaust ductwork upstream of the containment air filtration system exhaust filters that has a negative operating pressure are designed to meet at least SMACNA design standards.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
	ASME AG-1-1997, Section TA	Conforms	
C.4.1	ASME AG-1-1997, Section FB	Conforms	
C.4.2	ASME AG-1-1997, Section CA	Conforms	
C.4.3	ASME AG-1-1997, Section FC, and Section TA	Conforms	
C.4.4	ASME AG-1-1997, Section FG	Conforms	
C.4.5	ERDA 76-21, Section 4.4; ASME AG-1a-2000, Section HA	Conforms	
C.4.6	ASME N509-1989, Section 5.6; ASME AG-1a-2000, Section HA	Conforms	
C.4.7	ASME AG-1-1997, Section CA	Conforms	
C.4.8	ASME AG-1-1997, Section FD or FE	Conforms	
C.4.9	ASME AG-1-1997, Section FD and FE or, Section FF	Conforms	
C.4.10	ASME AG-1-1997 Section SA	Exception	Exhaust ductwork upstream of the containment air filtration system exhaust filters that has a negative operating pressure are designed to meet at least SMACNA design standards.
C.4.11		Conforms	
C.4.12	ASME AG-1-1997 Section DA	Conforms	
C.4.13	ASME AG-1-1997, Section BA and SA	Conforms	

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.5.1	ERDA 76-21, Section 2.3.8; ASME AG-1a-2000, Section HA	Conforms	
C.5.2		Conforms	
C.6	ASME N510-1989	Conforms	
C.7	ANSI N509-1989	Conforms	
Reg. Guide 1.141, Rev. 0, 4/78 – Containment Isolation Provisions for Fluid Systems			
General	ANSI N271-1976	Exception	Regulatory Guide 1.141 endorses ANSI N271-1976 (Reference 41) that has been superseded by ANS 56.2-1984 (Reference 42). The AP1000 uses the latest version of industry standards (as of 4/2001). This version is not endorsed by a regulatory guide but its use should not result in deviations from the design philosophy otherwise stated in Regulatory Guide 1.141. Containment isolation for AP1000 fluid systems conforms to Reference 42 with the following exceptions and/or clarifications. ANS 56.2-1984, Section 3.6.3 states that "remote manual closure of isolation valves on engineered safeguards features or engineered safeguards features-related systems is acceptable when provisions are made to detect possible failure of the fluid lines inside and outside containment." The AP1000 engineered safeguards features are designed to avoid the need for transport of post-accident fluids outside of containment and thus avoid the concern associated with remote manual isolation of engineered safety feature lines. Non-engineered safety feature lines capable of providing engineered safety feature functions are provided with the capability for remote manual isolation. The nonsafety-related normal residual heat removal system has provisions to isolate on high containment radiation. Radiation monitors are provided inside containment to assess continuation of the functions.
C.1		Conforms	
C.2		Conforms	
C.3		Conforms	

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.4	ANSI N271-1976, Section 4.4.8, Section 3.5 or 3.6.7	Conforms	
C.5	Regulatory Guide 1.7 & 1.89	Conforms	
C.6	ANSI N271-1976, Section 3.5 or 3.7	Conforms	

Reg. Guide 1.142, Rev. 2, 11/01 – Safety-Related Concrete Structures for Nuclear Power Plants (Other than Reactor Vessels and Containments)

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
General	ACI 349-97	Exception	Regulatory Guide 1.142 endorses ACI 349-97 (Reference 43) that has been superseded by ACI 349-01 (Reference 44). The AP1000 uses the latest version of industry standards as of October 2001). This version is not endorsed by a regulatory guide but its use should not result in deviations from the design philosophy otherwise stated in Regulatory Guide 1.142. In the following evaluation of conformance, the design is shown as conforming since the requirements of ACI-2001 are similar to those of ACI349-1997.
C.1		N/A	The compartments within the containment are not designed to be leaktight since they must communicate with one another to preclude subcompartment pressurization. Therefore, this guideline is not applicable to the AP1000.
C.2	ANS 6.4-1997	Conforms	
C.3	ANSI/ACI 349-97	Conforms	
C.4		Conforms	
C.5		Conforms	
C.6	ACI 349-97, Section 9.2.1	Conforms	
C.7		Conforms	
C.8		Conforms	
C.9		N/A	The AP1000 does not include a pressure-suppression containment. Therefore, this guideline is not applicable to the AP1000.
C.10	ACI 349-97, App. C	Conforms	

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.11		Conforms	
C.12	ACI 349-97, App. A	Conforms	
C.13		Conforms	
C.14		N/A	The AP1000 containment vessel is steel.
C.15		Conforms	The provisions in Section 11.6 of ACI 349-01 are the same as those in ACI 318-99 (Reference 46).
Reg. Guide 1.143, Rev. 2, 11/01 – Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants			
General			The AP1000 Radwaste Building provides space to store dry active waste and space for mobile waste processing systems and equipment. It does not contain installed systems and components used to process, store, or handle gaseous or liquid waste.
C.1.1.1	Regulatory Guide 1.143, Table 1	Conforms	Components in the liquid radwaste systems are designed and tested to the requirements set forth in the codes and standards listed in Table 1 of Regulatory Guide 1.143. Equipment classifications and design codes are listed in Table 3.2-3. Pressure vessels are designed and built according to ASME, Section VIII, Div. 1. Atmospheric tanks are per API 650 or ASME, Section III and heat exchangers to ASME Section VIII, Div. 1 and TEMA (for shell and tube). Piping and valves are per ANSI B31.1 except the containment penetrations and isolation valves are per ASME, Section III, Class 2. Pumps are according to manufacturer's standards.
C.1.1.2	ASME Code, Section II	Conforms	Materials, except elastomers for gaskets, seals, seats, diaphragms, and packing, are provided in accordance with the ASME Code, Section II when the ASME Code is the design and fabrication standard. Piping and valves materials are per ASTM specifications consistent with ANSI B31.1. Pump materials are provided according to manufacturer's standards.
C.1.1.3		Conforms	The auxiliary building that contains the liquid radwaste system is designed to Seismic Category I criteria. The Seismic Category I structure will retain the maximum liquid inventory of the system. The lowest level of the auxiliary building, elevation 66′6″, contains the liquid radwaste system effluent holdup tanks, waste holdup tanks, a monitor tank and chemical waste tank within a

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			common flood zone. This flood zone has watertight floors and walls. The enclosed volume within this flood zone is sufficient to contain the contents of the system. The tank rooms each have one or two floor drains that lead to the sump. Tank overflows or spills will be collected in the auxiliary building sump. The sump is automatically pumped to a waste holdup tank. Two liquid radwaste system monitor tanks are three levels up at elevation 100′-0″. Overflows or spills from these monitor tanks drain by gravity down through the drain system to a waste holdup tank. The Seismic Category I criteria exceed the operating basis earthquake required by regulatory position C.6 of Regulatory Guide 1.143.
C.1.2.1		Conforms	Atmospheric tanks in the liquid radwaste system have level sensors, transmitters, and alarms. Local alarm is not provided because the tanks are located in shielded areas that are not normally occupied by people.
C.1.2.2		Conforms	Tank overflows, drains and sample lines that may contain radioactive water are routed to the liquid radwaste system for processing.
C.1.2.3		Conforms	Please refer to the discussion of conformance to C.1.1.3, which addresses the provisions in the buildings that contain radioactive waste to contain any spills.
C.1.2.4		Conforms	Please refer to the discussion of conformance to C.1.1.3, which addresses the provisions in the building that contain radioactive waste to contain any spills. The measures to prevent contamination of clean areas via ductwork due to leakage are as follows: the annex building general area HVAC system normally maintains the personnel areas at a slightly positive pressure with respect to adjacent areas, including the auxiliary building. Interfaces with the adjacent buildings are limited to doorways, airlocks, and ductwork. Ductwork connecting the annex building and adjacent areas consists entirely of supply air ductwork handling outside air for the fuel handling area, health physics area, containment purge supply, and main control room. The main control room supplemental air filtration unit is in the HVAC equipment room; however, this unit has no radioactive material during normal plant operation.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.1.2.5		Conforms	This guideline does not apply because the liquid radwaste treatment system has no outdoor tanks. No other outside tanks store radioactive fluids.
C.2.1	Regulatory Guide 1.143, Table 1	Conforms	Components in the gaseous radwaste systems are designed and tested to the requirements set forth in the codes and standards listed in Table 1 of Regulatory Guide 1.143. Heat exchangers are designed and built according to ASME, Section VIII, Div. 1 and TEMA (for shell and tube). Piping and valves are per ANSI B31.1. Pumps are according to manufacturer's standards.
C.2.2	ASME Code, Section II	Conforms	Materials, except elastomers for gaskets, seals, seats, diaphragms, and packing, are provided in accordance with the ASME Code Section II when the ASME Code is the design and fabrication standard. Piping and valves materials are per ASTM specifications consistent with ANSI B31.1. Pump materials are provided according to manufacturer's standards.
C.2.3		Conforms	The guard bed and the delay beds, including supports, in the gaseous radwaste system are designed for seismic loads according to the requirements of Regulatory Guide 1.143. These are the only AP1000 components used to store or delay the release of gaseous radioactive waste. The beds are located in the seismic Category I auxiliary building at elevation 66′-6″. Seismic loads for this equipment will be established using one-half of the safe shutdown earthquake (SSE) floor response spectra. The loads due to this seismic response spectra are equivalent or greater than those due to an operating basis earthquake (OBE). Other equipment and supports will be designed in accordance with the codes indicated in Table 3.2-3.
C.3		Conforms	The regulatory guidance applies to the AP1000 solid waste processing system except for components and subsystems used to solidify or concentrate liquid waste. The AP1000 solid waste processing system does not have these components/subsystems. These functions are provided by contractors who process these wastes using mobile systems.
C.3.1	Regulatory Guide 1.143, Table 1, Reg. Pos. 3.2 and 3.3	Conforms	The solid radwaste system is designed and tested to the requirements set forth in the codes and standards listed in Table 1 of Regulatory Guide 1.143. The spent resin tanks are designed and tested in accordance with ASME Code, Section VIII, Div. 1. Piping and valves are

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			designed and tested according to ANSI B31.1. The pumps are designed to manufacturers' standards and tested in accordance with the Hydraulic Institute standards.
C.3.2	ASME Code, Section II	Conforms	Materials, except elastomers for gaskets, seals, seats, diaphragms, and packing, are provided in accordance with the ASME Code, Section II when the ASME Code is the design and fabrication standard. Piping and valves materials are per ASTM specifications consistent with ANSI B31.1. Pump materials are provided according to manufacturer's standards.
C.3.3		Conforms	The Seismic Category I auxiliary building will retain the maximum liquid and spent resin inventory of the spent resin tanks. The Seismic Category I criteria exceed the operating basis earthquake required by regulatory position C.6 of Regulatory Guide 1.143.
C.3.4		Conforms	The equipment and components used to collect, process, and store solid radwaste are nonseismic as permitted by this paragraph.
C.4.1	Regulatory Guide 8.8	Conforms	Design Control Document section 12, "Radiation Protection," discusses the measures taken to maintain the radiation exposure to personnel as low as reasonably achievable.
C.4.2		Conforms	The quality assurance program for design, fabrication, procurement, and installation of radwaste systems is in accordance with the overall quality assurance program described in Chapter 17, which meets the requirements of Regulatory Guide 1.143, position C.7.
C.4.3	ASME Code, Section IX	Conforms	Pressure-containing components in the radwaste systems are of welded construction to the maximum practical extent. Flanged joints and quick connect fittings are used only where maintenance or operational requirements indicate that they are preferable. Screwed connections are not used except for some instrumentation and vents and drains where welded construction is not suitable. Process lines are 1 in. or larger. Butt welds are used in process lines, which contain radioactive fluids. Nonconsumable backing rings are not used in process piping welds. Process pipe welding is performed as required by ANSI B31.1. Component welding is performed as required by the applicable construction code.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.4.4		Conforms	Hydrostatic testing is performed as required by the applicable construction codes.
C.4.5		Conforms	In-service testing of the containment penetrations and isolation valves is performed as described in Design Control Document subsection 3.9.6. Other tests, on nonsafety equipment, are performed on an item-by-item basis as judged necessary to confirm proper operation of the systems.
C.5	10 CFR Part 20		
C.5.1		Conforms	Systems containing enough activity to be possibly classified as RW-IIa are located in the Auxiliary Building. The Auxiliary Building is Seismic Category I.
C.5.2		Conforms	
C.5.3	10 CFR Part 71 Appendix A	Conforms	AP1000 systems and components that store or process radioactive waste are located in the Auxiliary Building.
C.5.4	10 CFR Part 71 Appendix A	Conforms	AP1000 systems and components that store or process radioactive waste are located in the Auxiliary Building.
C6.1.1	Table 2	Conforms	
C6.1.2	Table 3	Conforms	
C6.1.3	Table 4	Conforms	
C6.1.4	Table 1 & 4	Conforms	
C6.2.1	UBC 1997, ASCE 7-95	Conforms	The Radwaste Building is designed to UBC-1997 and ASCE 7-98.
C6.2.2		Conforms	Shield structures, if used, will comply with Regulatory Guide 1.143, position C.6.2.
C.7	ANSI/ANS55.6-1993	Conforms	The quality assurance program for design, fabrication, procurement, and installation of radwaste systems is in accordance with the overall quality assurance program described in Chapter 17, which meets the requirements of Regulatory Guide 1.143, position C.6.

Reg. Guide 1.144 – Withdrawn

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.145, Rev. 1, 11/82 – Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants			
General		N/A	The atmospheric dispersion factors for use in determining potential accident consequences are selected to be representative of existing nuclear power plant sites and to bound the majority of them. Chapter 2 provides the interface criteria. Therefore, this regulatory guide is not applicable to AP1000 design certification.
Reg. Guide 1.146 – Withdrawn			
Reg. Guide 1.147, Rev. 12, 5/99 – Inservice Inspection Code Case Acceptability ASME Section XI Division 1			
General	ASME Code, Section XI	Conforms	
Reg. Guide 1.148, (Task SC 704-5), Rev. 0, 3/81 – Functional Specification for Active Valve Assemblies in Systems Important to Safety in Nuclear Power Plants			
General	ANSI N27.8.1-1975	Conforms	
C.1.a		Conforms	
C.1.b	ASME Code, Section III, NCA-3250	Conforms	
C.1.c(1)	ASME Code, Section III, NCA-3252(a)(b)	Conforms	
C.1.c(2)		Conforms	
C.1.c(3)	ASME Code, Section III, NCA-3256	Conforms	
C.1.d		Conforms	
C.1.e	Regulatory Guide 1.84, Regulatory Guide 1.85	Conforms	
C.2.a-d		Conforms	
Reg. Guide 1.149, Rev. 2, 4/96 – Nuclear Power Plant Simulation Facilities for Use in Operator License Examinations			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.150, Rev. 1, 2/83 – Ultrasonic Testing of Reactor Vessel Welds During Preservice and Inservice Examinations			
General		Conforms	The reactor vessel design includes features that permit conformance to the pre-service and in-service inspection of this regulatory guide. Guidelines for such features as positioning of welds, vessel contour, and weld surface preparation are included.
Reg. Guide 1.151, (Task 1C 126-5), Rev. 0, 7/83 – Instrument Sensing Lines			
General	ISA-S67.02	Conforms	This regulatory guide addresses the difference between the pressure boundary integrity of an instrument sensing line in accordance with the appropriate parts of ASME Code, Section III, or ANSI B31.1, as applicable, and the availability of the protection function of safety-related instruments. Industry standard ISA-S67.02 reiterates and clarifies the practice of controlling documents such as interface requirements and regulations. The AP1000 uses the Piping and Instrumentation Diagram as the approved document to designate the safety classification system boundaries.
C.1		Conforms	
C.2	ASME Code, Class 2 SC I	Conforms	Safety-related instrumentation has safety class pressure boundaries, including the sensing line, valves, and instrumentation sensors. The pressure boundary is the same safety class as the equipment to which it is connected. The AP1000 credits design features such as flow restrictors and diaphragms as class separation. For that portion of a sensing line from the ASME Code, Class 1 piping or vessel out to the class separation device, ISA-S67.02 includes the ASME Code, Class 1 requirement. For that portion of the sensing line from the class separation device to the sensor is designated as ASME Code, Class 2 requirement. The AP1000 has no sensing lines penetrating the containment barrier.
C.3	ASME Code, Class 3 SC I	Exception	The guidelines apply to the AP1000 sensing lines, except the sensing lines that are connected to some ASME Code, Class 3 components that do not have a seismic design requirement. Sensing lines from these components are not ASME Code, seismic Category I.
C.4-6		Conforms	

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.152, (Task 1C 127-5), Rev. 1, 1/96 – Criteria for Programmable Digital Computer System Software in Safety-Related Systems of Nuclear Power Plants			
General	ANSI/IEEE-ANS-7-4.3.2-1993	Conforms	
Reg. Guide 1.153, Rev. 1, 6/96 – Criteria for Power, Instrumentation, and Control Portions of Safety Systems			
General	IEEE Std. 603-1991 including January 30, 1995 Correction sheet	Conforms	
Reg. Guide 1.154, Rev. 0, 1/87 – Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility. See Section 5.3 for additional information on pressurized thermal shock.
Reg. Guide 1.155, (Task SI 501-4), Rev. 0, 8/88 – Station Blackout			
General	10 CFR 50.63	N/A	There are no safety-related ac power sources. Therefore, this regulatory guide is not applicable to the AP1000.
Reg. Guide 1.156, (Task EE 404-4), Rev. 0, 11/87 – Environmental Qualification of Connection Assemblies for Nuclear Power Plants			
General	IEEE Std. 572-1985	Conforms	
Reg. Guide 1.157, (Task RS 701-4), Rev. 0, 5/89 – Best-Estimate Calculations of Emergency Core Cooling System Performance			
C.1		Conforms	
C.2		Conforms	
C.3.1	10 CFR 50, App. A	Conforms	
C.3.2-12		Conforms	
C.3.13-14		N/A	Applies to boiling water reactors only.
C.3.15-16		Conforms	
C.4.1	10 CFR 50.46(a)(1)(i)	Conforms	
C.4.2-4		Conforms	

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
C.4.5		Conforms	

Reg. Guide 1.158, (Task EE 006-5), Rev. 0, 2/89 – Qualification of Safety-Related Lead Storage Batteries for Nuclear Power Plants

General	IEEE Std. 535-1986	Conforms	

Reg. Guide 1.159, Rev. 0, 8/90 – Assuring the Availability of Funds for Decommissioning Nuclear Reactors

General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.

Reg. Guide 1.160, Rev. 2, 3/97 – Monitoring the Effectiveness of Maintenance at Nuclear Power Plants

General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.

Reg. Guide 1.161, Rev. 0, 6/95 – Evaluation of Reactor Pressure Vessels with Charpy Upper-Shelf Energy Less Than 50 Ft-Lb

General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility. The design and material specification for the reactor vessel do not permit a Charpy value less than 50 ft.-lb.

Reg. Guide 1.162, Rev. 0, 2/96 – Format and Content of Report for Thermal Annealing of Reactor Pressure Vessels

General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.

Reg Guide 1.163, Rev. 0, 9/95 – Performance Based Containment Leak-Test Program

1	NEI94-01 ANSI/ANS 56.8-1994	Conforms	
2	NEI Section 11.3.2	Conforms	
3	NEI 94-01 Section 9.2.1 NEI 94-01 Section 10.2.3.3	Conforms	

Reg. Guide 1.165, Rev. 0, 3/97 – Identification and Characterization of Seismic Sources and Determination Safe Shutdown Earthquake Ground Motion

General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.166, Rev. 0, 3/97 – Pre-Earthquake Planning and Immediate Nuclear Power Plant Operator Postearthquake Actions			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
Reg. Guide 1.167, Rev. 0, 3/97 – Restart of a Nuclear Power Plant Shut Down by a Seismic Event			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
Reg. Guide 1.168, Rev. 0, 9/97 – Verification, Validation, Reviews, and Audits for Digital Computer Software Used in Safety Systems of Nuclear Power Plants			
General		N/A	Not applicable to AP1000 design certification. Digital computer software is not finalized for design certification. See Chapter 7 for a discussion of the methodology used.
Reg. Guide 1.169, Rev. 0, 9/97 – Configuration Management Plans for Digital Computer Software Used in Safety Systems of Nuclear Power Plants			
General		N/A	Not applicable to AP1000 design certification. Digital computer software is not finalized for design certification. See Chapter 7 for a discussion of the methodology used.
Reg. Guide 1.170, Rev. 0, 9/97 – Software Test Documentation for Digital Computer Software Used in Safety Systems of Nuclear Power Plants			
General		N/A	Not applicable to AP1000 design certification. Digital computer software is not finalized for design certification. See Chapter 7 for a discussion of the methodology used.
Reg. Guide 1.171, Rev. 0, 9/97 – Software Unit Testing for Digital Computer Software Used in Safety Systems of Nuclear Power Plants			
General		N/A	Not applicable to AP1000 design certification. Digital computer software is not finalized for design certification. See Chapter 7 for a discussion of the methodology used.
Reg. Guide 1.172, Rev. 0, 9/97 – Software Requirements Specifications for Digital Computer Software Used in Safety Systems of Nuclear Power Plants			
General		N/A	Not applicable to AP1000 design certification. Digital computer software is not finalized for design

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
			certification. See Chapter 7 for a discussion of the methodology used.

Reg. Guide 1.173, Rev. 0, 9/97 – Developing Software Life Cycle Processes for Digital Computer Software Used in Safety Systems of Nuclear Power Plants

General		N/A	Not applicable to AP1000 design certification. Digital computer software is not finalized for design certification. See Chapter 7 for a discussion of the methodology used.

Reg. Guide 1.174, Rev. 0, 7/98 – An Approach for using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis

General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.

Reg. Guide 1.175, Rev. 0, 7/98 – An Approach for Plant-Specific, Risk-Informed Decisionmaking: Inservice Testing

General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.

Reg. Guide 1.176, Rev. 0, 8/98 – An Approach for Plant-Specific, Risk-Informed Decisionmaking: Graded Quality Assurance

General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.

Reg. Guide 1.177, Rev. 0, 8/98 – An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications

General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.

Reg. Guide 1.178, Rev. 0, 9/98 – An Approach for Plant-Specific Risk-informed Decisionmaking Inservice Inspection of Piping

General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.

Reg. Guide 1.179, Rev. 0, 9/99 – Standard Format and Content of License Termination Plans for Nuclear Power Reactors

General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.180, Rev. 0, 9/00 – Guidelines for Evaluating Electromagnetic and Radio-Frequency Interference in Safety-Related Instrumentation and Control Systems			
General		N/A	Not applicable to AP1000 design certification. Digital computer software is not finalized for design certification. See Chapter 7 for a discussion of the methodology used.
Reg. Guide 1.181, Rev. 0, 9/99 – Content of the Updated Final Safety Analysis Report in Accordance with 10 CFR 50.71(e)			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
Reg. Guide 1.182, Rev. 0, 5/00 – Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
Reg. Guide 1.183, Rev. 0, 7/00 – Alternative Radiological Source Terms For Evaluating Design Basis Accidents At Nuclear Power Reactors			
General		Conforms	
Reg. Guide 1.184, Rev. 0, 8/00 – Decommissioning of Nuclear Power Reactors			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
Reg. Guide 1.185, Rev. 0, 8/00 – Standard Format and Content for Post-shutdown Decommissioning Activities Report			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
Reg. Guide 1.186, Rev. 0, 12/00 – Guidance and Examples of Identifying 10 CFR 50.2 Design Bases			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
Reg. Guide 1.187, Rev. 0, 11/00 – Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 1.189, Rev. 0, 4/01 – Fire Protection for Operating Nuclear Power Plants			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
Reg. Guide 1.190, Rev. 0, 4/01 – Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
DIVISION 4 – Environmental and Siting			
Reg. Guide 4.7 Rev. 2, 4/98 – General Site Suitability Criteria for Nuclear Power Stations			
General		N/A	Chapter 2 defines the site-related parameters for which the AP1000 plant is designed. These interface parameters envelop most potential sites in the United States. The guidelines in this regulatory guide are site-specific. Therefore, this regulatory guide is not applicable to AP1000 design certification.
DIVISION 5 – Materials and Plant Protection			
Reg. Guide 5.9 Rev. 2, 12/83 – Specifications for Ge (Li) Spectroscopy Systems for Material Protection Measurements Part 1: Data Acquisition Systems			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
Reg. Guide 5.12, Rev. 0, 11/73 – General Use of Locks in the Protection and Controls of Facilities and Special Nuclear Materials			
C.1	UL-768	Conforms	
C.2	FF-P-110F	Conforms	
C.3	UL-437	Conforms	
C.4	FF-P-001480 (GSA FSS)	Conforms	
C.5-8		Conforms	

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
Reg. Guide 5.65, Rev. 0, 9/86 – Vital Area Access Controls, Protection of Physical Security Equipment, and Key and Lock Controls			
General		Conforms	The AP1000 provides for physical protection of the vital area. Identification of the protected and vital areas and an outline of the physical protection system is presented in the AP1000 Security Design Report. Portions of the access controls addressed by the regulatory guide are the Combined License applicant's responsibility. See subsection 13.6.13 for Combined License applicant information items.
DIVISION 8 – Occupational Health			
Reg. Guide 8.2, Rev. 0, 2/73 – Guide for Administrative Practices in Radiation Monitoring			
General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility. See Section 13.5 for the Combined License information item for administrative procedures.
Reg. Guide 8.8, Rev. 3, 6/78 – Information Relevant to Ensuring That Occupational Radiation Exposures at Nuclear Power Stations Will Be As Low As Is Reasonably Achievable			
1		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
1.a-c	Regulatory Guide 1.8	N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
1.d		Conforms	
2	ANSI N237-1976	Exception	Regulatory Guide 8.8 endorses ANSI-N237-1976 (Reference 49), which has been superseded by ANSI 18.1-1999 (Reference 50). The AP1000 uses the latest version of the industry standards (as of 4/2001). This version is not endorsed by a regulatory guide but its use should not result in deviation from the design philosophy otherwise stated in Regulatory Guide 8.8.
2.a	10 CFR 20-203	Conforms	
2.b-g		Conforms	
2.h	ANS N197 ANS 55.1 ANS N19	Conforms	 ANS-55.1-1992-R2000 is Current Version
2.i		Conforms	

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
3		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
4.a		Conforms	
4.b-d		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.
4.3		Conforms	

Reg. Guide 8.10, Rev. 1-R, 5/77 – Operating Philosophy For Maintaining Occupational Radiation Exposures as Low as is Reasonably Achievable

General		N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility.

Reg. Guide 8.12 – Withdrawn

Reg. Guide 8.13, Rev. 3, 6/99 – Instruction Concerning Prenatal Radiation Exposure

General	10 CFR 19.12	N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility. See Section 13.5 for the Combined License information item for administrative procedures.

Reg. Guide 8.14 – Withdrawn

Reg. Guide 8.15, Rev. 1, 10/99 – Acceptable Programs for Respiratory Protection

General	10 CFR 20.103	N/A	Not applicable to AP1000 design certification. This is the Combined License applicant's responsibility. See Section 12.3 for information on radiation protection design features. See Section 12.5 for information on health physics facilities. See Section 13.5 for the Combined License information item for administrative procedures.

Reg. Guide 8.19, Rev. 1, 6/79 – Occupational Radiation Dose Assessment in Light-Water Reactor Power Plants Design Stage Man-Rem Estimates

General		Conforms	

Reg. Guide 8.38, Rev. 0, 6/93 – Control of Access to High and Very High Radiation Areas of Nuclear Plants

General		Conforms	

1A.1 References

1. Sofer, et al., "Accident Source Terms for Light Water Nuclear Power Plants." NUREG-1465, February 1995.

2. Not used.

3. Not used.

4. Not used.

5. IEEE Std. 308-1974, IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations, 1974.

6. IEEE Std. 308-1991, IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations, 1991.

7. Not used.

8. Not used.

9. WCAP-8577, "The Application of Pre-Heat Temperature After Welding of Pressure Vessel Steels," September 1975.

10. IEEE 379-72, IEEE Trial-Use Guide for the Application of the Single-Failure Criterion to Nuclear Power Generating Station Protection Systems, 1972.

11. IEEE 379-2000, IEEE Standard Application of the Single-Failure Criterion to Nuclear Power Generating Station Safety Systems, 2000.

12. ASCE 4-86, Seismic Analysis of Safety-Related Nuclear Structures, September 1986.

13. RESAR/SP90, Westinghouse Advanced Pressurized Water Reactor, Paragraph 3.7.1.3, Damping Values, January 1989.

14. Design & Evaluation Guideline for Department of Energy Facilities Subjected to Natural Phenomena Hazards, Lawrence Livermore National Laboratory, UCRL-15910, R. P. Kennedy et al., May 1989.

15. IEEE 741-1986, IEEE Standard Criteria for Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations, 1986.

16. IEEE Std. 741-1997, IEEE Standard Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations, 1997.

17. IEEE 317-1983, IEEE Standard for Electric Penetrations Assemblies in Containment Structures for Nuclear Power Generating Stations, 1983.

18. ANSI N101.6-1972, Atomic Industry Facility Design, Construction, and Operation Criteria, December 22, 1972.

19. ANSI/ANS 6.4 1997, Guidelines on the Nuclear Analysis and Design of Concrete Radiation Shielding for Nuclear Power Plants.

20. Not used.

21. IEEE 382-1996, IEEE Standard for Qualification of Actuators for Power-Operated Valve Assemblies with Safety-Related Functions for Nuclear Power Plants, 1996.

22. IEEE 323-1974, IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations, 1974.

23. IEEE 384-74, IEEE Trial-Use Standard Criteria for Separation of Class 1E Equipment and Circuits, 1974.

24. IEEE 384-81, IEEE Standard Criteria for Independence of Class 1E Equipment and Circuits, 1981.

25. ANS 5.4-1982, American National Standard Method for Calculating the Fractional Release of Volatile Fission Products From Oxide Fuel, 1982.

26. Title 10 Code of Federal Regulations Part 50, 50.49, Environmental qualification of electric equipment important to safety for nuclear power plants.

27. IEEE Std. 279-1971, IEEE Standard Criteria for Protection Systems for Nuclear Power Generating Stations, 1971.

28. NRC Safety Evaluation Report, letter from B. D. Liaw to J. A. Martin, December 27, 1984.

29. WCAP-15783-P (Proprietary) and WCAP-15783-NP (Non-Proprietary), "Analysis of the Probability of the Generation of Missiles from Fully Integral Nuclear Low Pressure Turbines," Revision 2, August 2003.

30. Not used.

31. IEEE Std. 338-1987, IEEE Standard Criteria for the Periodic Surveillance Testing of Nuclear Power Generating Stations Safety Systems, 1987.

32. BTP CMEB 9.5.1, "Guidelines for Fire Protection for Nuclear Power Plants."

33. SRP (NUREG-0800) Section 9.5.1 "Fire Protection Program," Revision 3, July 1986.

34. Guide to Design Criteria for Bolted and Riveted Joints, Fisher and Struik, copyright 1974, John Wiley and Sons.

35. Not used.

36. IEEE 484-75, IEEE Recommended Practice for Installation Design and Installation of Large Lead Storage Batteries for Generating Stations and Substations, 1975.

37. IEEE 484-1996, IEEE Recommended Practice for Installation Design and Installation of Large Lead Storage Batteries for Generating Stations and Substations, 1996.

38. ASME AG-1-1997, "Code on Nuclear Air and Gas Treatment," 1997.

39. ASME Code N509-1989, "Nuclear Power Plant Air Cleaning Units and Components," 1989.

40. ASME Code N510-1989, "Testing of Nuclear Air Cleaning Systems," 1989.

41. ANSI N271-1976, "Containment Isolation Provisions for Fluid Systems," 1976.

42. ANS 56.2-1984, Containment Isolation Provisions for Fluid Systems, 1984.

43. ACI 349-97, "Code Requirements for Nuclear Safety Related Concrete Structures," 1997.

44. ACI 349-01, "Code Requirements for Nuclear Safety Related Concrete Structures," 2001.

45. Not used.

46. ACI 318-99, "Building Code Requirements for Reinforced Concrete," 1999.

47. Not used.

48. Not used.

49. ANSI N237-1976, Source Term Specification, 1976.

50. ANSI/ANS 18.1-1999, Radioactive Source Term for Normal Operation of Light Water Reactors, 1999.

51. IEEE Std. 603-1991, IEEE Standard Criteria for Power Generating Stations, 1991.

APPENDIX 1B

SEVERE ACCIDENT MITIGATION DESIGN ALTERNATIVES

1B.1 AP1000 SAMDA Evaluation

1B.1.1 Introduction

This response provides an evaluation of Severe Accident Mitigation Design Alternatives (SAMDA) for the Westinghouse AP1000 design. This evaluation is performed to evaluate whether or not the safety benefit of the SAMDA outweighs the costs of incorporating the SAMDA in the plant, and is conducted in accordance with applicable regulatory requirements as identified below.

The National Environmental Policy Act (NEPA), Section 102.(C)(iii) requires, in part, that:

> ... all agencies of the Federal Government shall ... (C) include in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment, a detailed statement by the responsible official on ... (iii) alternatives to the proposed action.

The 10 CFR 52.47(a)(ii) requires an applicant for design certification to demonstrate:

> ... compliance with any technically relevant portions of the Three Mile Island requirements set forth in 10 CFR 50.34(f) ...

A relevant requirement of 10 CFR 50.34(f) contained in subparagraph (1)(i) requires the performance of:

> ... a plant/site specific probabilistic risk assessment, the aim of which is to seek such improvements in the reliability of core and containment heat removal systems as are significant and practical and do not impact excessively on the plant ...

In SECY-91-229, the U.S. Nuclear Regulatory Commission (NRC) staff recommends that SAMDAs be addressed for certified designs in a single rulemaking process that would address both the 10 CFR 50.34 (f) and NEPA considerations in the 10 CFR Part 52 design certification rulemaking. SECY-91-229 further recommends that applicants for design certification assess SAMDAs and the applicable decision rationale as to why they will or will not benefit the safety of their designs. The Commission approved the staff recommendations in a memorandum dated October 25, 1991 (Reference 1).

1B.1.2 Summary

Note that the AP1000 is similar to the AP600, which has received Design Certification. The evaluation for AP1000 uses the conclusions of the AP600 SAMDA investigation as described below. An evaluation of candidate modifications to the AP600 design was conducted to evaluate the potential for such modifications to provide significant and practical improvements in the

radiological risk profile of the AP600 design. Since the AP1000 is so similar to the AP600, the list of candidate modifications is the same.

The process used for identifying and selecting candidate design alternatives included a review of SAMDAs evaluated for other plant designs. Several SAMDA designs evaluated previously for other plants were excluded from the present evaluation because they have already been incorporated or otherwise addressed in the AP600 and AP1000 designs. These include the following:

- Hydrogen ignition system
- Reactor cavity flooding system
- Reactor coolant pump seal cooling
- Reactor coolant system depressurization
- Reactor vessel exterior cooling.

Additional design alternatives were identified based upon the results of the AP600 probabilistic risk assessment (Reference 3). The AP1000 probabilistic risk results are similar to those developed for the AP600. Fifteen candidate design alternatives were selected for further evaluation.

An evaluation of these alternatives was performed using a bounding methodology such that the potential benefit of each alternative is conservatively maximized. As part of this process, it was assumed that each SAMDA performs beyond expectations and completely eliminates the severe accident sequences that the design alternative addresses. In addition, the capital cost estimates for each alternative were intentionally biased on the low side to maximize the risk reduction benefit. This approach maximizes the potential benefits associated with each alternative.

The results show, for the AP600 and AP1000, that despite the significant conservatism used in the evaluation, none of the SAMDAs evaluated provide risk reductions that are cost beneficial. The results also show that even a conceptual "ideal SAMDA," one which reduces the total plant radiological risk to zero, would not be cost effective. This is due primarily to the already low-risk profile of the AP600 and AP1000 designs.

1B.1.3 Selection and Description of SAMDAs

Candidate design alternatives were selected based upon design alternatives evaluated for other plant designs (References 4, 5, and 6) as well as suggestions from AP600 and AP1000 design personnel. Additional candidate design alternatives were selected based upon an assessment of the AP600 and AP1000 probabilistic risk assessment results. SAMDA design alternatives were finally selected for further evaluation. These SAMDAs are as follows:

- Chemical, volume, and control system (CVS) upgraded to mitigate small loss-of-coolant accidents (LOCAs)

- Filtered containment vent

- Normal residual heat removal system (RNS) located inside containment

- Self-actuating containment isolation valves
- Passive containment spray
- Active high-pressure safety injection system
- Steam generator shell-side passive heat removal system
- Steam generator safety valve flow directed to in-containment refueling water storage tank (IRWST)
- Increase of steam generator secondary side pressure capacity
- Secondary containment filtered ventilation
- Diverse IRWST injection valves
- Diverse containment recirculation valves
- Ex-vessel core catcher
- High-pressure containment design
- Diverse actuation system improved reliability.

Each SAMDA and the benefit expected due to the modification is described below. In the evaluation of the risk reduction benefit, each SAMDA is assumed to operate perfectly with 100-percent efficiency, without failure of supporting systems. A perfect SAMDA reduces the frequency of accident sequences, which it addresses to zero. This is conservative as it maximizes the benefit of each design alternative. The SAMDA will reduce the risk by lowering the frequency, attenuating the release, or both. The benefit will be described in terms of the accident sequences and dose, which are affected by the SAMDAs, as well as the overall risk reduction. For these evaluations, increases to release category IC are not factored into the risk benefit calculations. The IC dose is sufficiently small that changes to the IC total frequency do not result in an appreciable change to overall results. This is also a conservative representation since this maximizes the risk reduction.

The cost benefit methodology of NUREG/BR-0184 (1997) is used to calculate the maximum attainable benefit. This includes replacement power costs. For expected benefit, the change in the CDF frequency (delta-F) is assumed to be equal to the sum of CDF frequencies from internal, external, and shutdown events that are already evaluated. This is bounding, used to calculate the maximum attainable benefit. In practice, there is no design alternative, or SAMDA strategy, whose implementation would reduce the plant CDF to zero (or to an infinitesimally small frequency).

Upgrade Chemical, Volume, and Control System for Small LOCAs

The chemical, volume, and control system is currently capable of maintaining the reactor coolant system inventory to a level in which the core remains covered in the event of a very small (< 3/8-inch diameter break) LOCA. This SAMDA involves providing IRWST containment recirculation connections to the chemical, volume, and control system and adding a second line from the chemical, volume, and control system makeup pumps to the reactor coolant system to be able to use the system to keep the core covered during small and intermediate LOCAs.

A perfect, upgraded chemical, volume, and control system is assumed to prevent core damage in the reactor coolant system leak, passive residual heat removal heat exchanger tube ruptures, small LOCA, and intermediate LOCA release categories. The chemical, volume, and control system is assumed to have perfect support systems (power supply and component cooling) and to work in all situations regardless of the common cause failures of other systems.

Filtered Vent

This SAMDA consists of placing a filtered containment vent and all associated piping and penetrations into the AP1000 containment design. The filtered vent could be used to vent the containment to prevent catastrophic overpressure failure, and it also provides filtering capability for source term release. With respect to the AP1000 Probabilistic Risk Assessment, the possible scenario in which the filtered vent could result in risk reduction would be late containment overpressure failures (release category CFL). Other containment overpressure failures occur due to dynamic severe accident phenomena, such as hydrogen burn and steam explosion. The late containment failures for AP1000 are failures of the passive containment cooling system. Analyses have indicated that for scenarios with passive containment cooling system failure, air cooling may limit the containment pressure to less than the ultimate pressure. However, for the Level 2 probabilistic risk assessment, failure of the passive containment cooling system is assumed to result in containment failure based on an adiabatic heatup. To conservatively consider the risk reduction of a filtered vent, the use of a filtered vent to preclude a late containment failure will be evaluated. A decontamination factor (DF) of 1000 will conservatively be assumed for each probabilistic risk assessment Level 1 accident classification, even though it is realized that the dose due to noble gases will not be impacted by the filtered vent since 100 percent of the noble gas fission products will still be released. Therefore, the risk reduction is equal to the decontamination factor assumed since the probabilistic risk assessment Level 1 accident classification frequencies do not change.

Self-Actuating Containment Isolation Valves

This SAMDA consists of improved containment isolation provisions on all normally open containment penetrations. The category of "normally open" is limited to normally open pathways to the environment during power and shutdown conditions, excluding closed systems inside and outside the containment such as normal residual heat removal system and component cooling. The design alternative would be to add a self-actuating valve or enhance the existing inside containment isolation valve to provide for self-actuation in the event that containment conditions are indicative of a severe accident. Conceptually, the design would be either an independent valve or an appendage to an existing fail-closed valve that would respond to post-accident containment

conditions within containment. For example, a fusible link would melt in response to elevated ambient temperatures resulting in venting the air operator of a fail-closed valve. This provides the self-actuating function. To evaluate the benefit of this SAMDA, this design change is assumed to eliminate the CI release category. This does not include induced containment failures that occur at the time of the accident, such as in cases of vessel rupture or anticipated transients without scram.

Passive Containment Sprays

This SAMDA involves adding a passive safety-related spray system and all associated piping and support systems to the AP1000 containment. A passive containment spray system could result in risk benefits in the following ways:

- Scrubbing of fission products could be done primarily for CI failures.
- Assuming appropriate timing, containment spray could be used as an alternate means for flooding the reactor vessel (in-vessel retention) and for debris quenching should vessel failure occur.
- Containment spray could also be used to control containment pressure for cases in which passive containment cooling system has failed.

In order to envelop these potential risk benefits, the risk reduction evaluation will assume that containment sprays are perfectly effective for each of these benefits, with the exception of fission product scrubbing for containment bypass. Thus, the risk reduction can be conservatively estimated by assuming all release categories except BP are eliminated.

Active High-Pressure Safety Injection System

This SAMDA consists of adding a safety-related active high-pressure safety injection pump and all associated piping and support systems to the AP1000 design. A perfect high-pressure safety injection system is assumed to prevent core melt for all events but excessive LOCA and anticipated transients without scram. Therefore, to estimate the risk reduction, only the contributions to each release category of Level 1 accident classes 3C (vessel rupture) and 3A (anticipated transients without scram) need to be considered. This SAMDA would completely change the design approach from a plant with passive safety systems to a plant with passive plus active safety-related systems, and it is not consistent with design objectives.

Steam Generator Shell-Side Heat Removal System

This SAMDA consists of providing a passive safety-related heat removal system to the secondary side of the steam generators. The system would provide closed loop cooling of the secondary using natural circulation and stored water cooling. This prevents a loss of primary heat sink in the event of a loss of startup feedwater and passive residual heat removal heat exchanger. A perfect secondary heat removal system would eliminate transients from each of the release categories. In order to evaluate the benefit of this SAMDA, the frequencies of all the transient sequences are subtracted from the overall frequency of each of the release categories and the risk is recalculated.

Direct Steam Generator Relief Flow to the In-containment Refueling Water Storage Tank

This SAMDA consists of providing all the piping and valves required for redirecting the flow from the steam generator safety and relief valves to the IRWST. An alternate, lower cost option of this SAMDA consists of redirecting only the first-stage safety valve to the IRWST. This system would prevent or reduce fission product release from bypassing the containment in the event of a steam generator tube rupture event. In order to evaluate the benefit from this SAMDA (both options), this design change is assumed to eliminate the BP release category.

Increased Steam Generator Pressure Capability

This SAMDA consists of increasing the design pressure of the steam generator secondary side and safety valve set point to the degree that a steam generator tube rupture will not cause the secondary system safety valve to open. The design pressure would have to be increased sufficiently such that the combined heat capacity of the secondary system inventory and the passive residual heat removal system could reduce the reactor coolant system temperature below T_{sat} for the secondary design pressure. Although specific analysis would have to be performed, it is estimated that the design pressure would have to be increased several hundred psi. This design would also prevent the release of fission products that bypass the containment via the steam generator tube rupture.

Secondary Containment Filtered Ventilation

This SAMDA consists of providing the middle and lower annulus (below the 135′-3″ elevation) of the secondary concrete containment with a passive annulus filter system to for filtration of elevated releases. The passive filter system is operated by drawing a partial vacuum on the middle annulus through charcoal and HEPA filters. The partial vacuum is drawn by an eductor with motive flow from compressed gas tanks. The secondary containment would then reduce particulate fission product release from any failed containment penetrations (containment isolation failure). In order to evaluate the benefit from such a system, this design change is assumed to eliminate the CI release category.

Diverse In-containment Refueling Water Storage Tank Injection Valves

This SAMDA consists of changing the IRWST injection valve designs so that two of the four lines use diverse valves. Each of the four lines is currently isolated by a squib valve in series with a check valve. In order to provide diversity, the valves in two of the lines will be provided by a different vendor. For the check valves, alternate vendors are available. However, it is questionable if check valves of different vendors would be sufficiently different to be considered diverse unless the type of check valve was changed from the current swing disk check to another type. The swing disk type is the preferred type for this application and other types are considered to be less reliable. Squib valves are specialized valve designs for which there are few vendors. A vendor may not be willing to design, qualify, and build a reasonable squib valve design for this AP1000 application considering that they would only supply two valves per plant. As a result, this SAMDA is not really practicable because of the uncertainty in availability of a second squib valve design/vendor and because of the uncertainty in the reliability of another check valve type. However, the cost estimate for this SAMDA assumes that a second squib valve vendor exists and

that the vendor provides only the two diverse IRWST squib valves. The cost impact does not include the additional first time engineering and qualification testing that will be incurred by the second vendor. Those costs are expected to be more than a million dollars.

This change will reduce the frequency of core melt by eliminating the common cause failure of the IRWST injection. To estimate the benefit from this SAMDA, all core damage sequences resulting from a failure of IRWST injection are assumed to be averted. Core damage sequences resulting from a failure of IRWST injection correspond to probabilistic risk assessment Level 1 accident classification 3BE; thus, release category 3BE is eliminated.

Diverse Containment Recirculation Valves

This SAMDA consists of changing the containment recirculation valve designs so that two out of the four lines use diverse valves. Each of the four lines currently contains a squib valve; two of the lines contain check valves, and the other two contain motor-operated valves. In order to provide diversity, the squib valves in two lines will be made diverse. This change will reduce the frequency of core melt by eliminating the common cause failure of the containment recirculation. To estimate the benefit from this SAMDA, all core damage sequences resulting from a failure of containment recirculation are assumed to be averted. Core damage sequences resulting from failure of containment recirculation correspond to probabilistic risk assessment Level 1 accident classification 3BL; thus, release category 3BL is eliminated.

In the AP1000 design for recirculation, valve diversity has been introduced to reduce some of the dominant failure modes that were discovered for the AP600.

The four AP600 recirculation squib valves were of the “low-pressure” type and were a part of a single common cause group. In the AP1000, two of these valves that are in series with check valves are designated to be of “high-pressure” type, which are in a common cause group with the same design of valves on the IRWST injection lines. Thus, the common cause failure mode that fails all four recirculation lines in the AP600 is eliminated, and it is replaced with the product of two common cause failure modes, one applicable to the group of six high-pressure squib valves and the other to the two low-pressure squib valves. This design change helps in reduction of recirculation failures.

Ex-Vessel Core Catcher

This SAMDA consists of designing a structure in the containment cavity or using a special concrete or coating that will inhibit core-concrete interaction (CCI), even if the debris bed dries out. A perfect core catcher would prevent CCI for all cases. However, the AP1000 incorporates a wet cavity design in which ex-vessel cooling is used to maintain the core debris in the vessel to prevent ex-vessel phenomena, such as CCI. Consequently, containment failure due to CCI is not considered in detail for the AP1000 Level 2 probabilistic risk assessment. For cases in which reactor vessel flooding is failed, it is assumed that containment failure occurs due to ex-vessel steam explosion or CCI. This containment failure is assumed to be an early containment failure, CFE (due to ex-vessel steam explosion) even though CCI and basemat melt-through would be a late containment failure. To conservatively estimate the risk reduction of an ex-vessel core catcher, this design change is assumed to eliminate the CFE release category.

High-Pressure Containment Design

This SAMDA design consists of using the massive high-pressure containment design in which the design pressure of the containment is approximately 300 psi (20 bar) for the AP1000 containment. The massive containment design has a passive containment cooling feature much like the AP1000 containment. The high design pressure is considered only for prevention of containment failures due to severe accident phenomena, such as steam explosions and hydrogen detonation. A perfect high-pressure containment design would reduce the probability of containment failures, but would have no reduction of the frequency or magnitude of the release from an unisolated containment (containment isolation failure or containment bypass). To estimate the risk reduction of a high-pressure containment design, this design is assumed to eliminate the CFE, CFI, and CFL release categories.

Increase Reliability of Diverse Actuation System

This SAMDA design consists of improving the reliability of the diverse actuation system, which actuates engineered safety features and allows the operator to monitor the plant status. The design change would add a third instrumentation and control cabinet and a third set of diverse actuation system instruments to allow the use of two-out-of-three logic instead of two-out-of-two logic. Other changes, such as adding another set of batteries, have not been included in the cost estimates. A perfectly reliable diverse actuation system would reduce the frequency of the release categories by the cumulative frequencies of all sequences in which diverse actuation system failure leads to core damage. In order to evaluate the benefit from the diverse actuation system upgrade, a Level 1 sensitivity analysis assuming perfect reliability of diverse actuation system was completed.

Locate Normal Residual Heat Removal Inside Containment

This SAMDA consists of placing the entire normal residual heat removal system and piping inside the containment pressure boundary. Locating the normal residual heat removal system inside the containment would prevent containment bypass due to interfacing system LOCAs (ISLOCA) of the residual heat removal system. In past probabilistic risk assessments of current generation nuclear power plants, the ISLOCA is the leading contributor of plant risk because of large offsite consequences. A failure of the valves which isolate the low-pressure residual heat removal system from the high pressure reactor coolant system causes the residual heat removal system to overpressurize and fail, releasing reactor coolant system coolant outside the containment where it cannot be recovered for recirculation cooling of the core. The result is core damage and the direct release of fission products outside the containment.

In the AP1000, the normal residual heat removal system is designed with a higher design pressure than the systems in current pressurized water reactors, and an additional isolation valve is provided in the design. In the probabilistic risk assessment, no ISLOCAs contribute significantly to the core damage frequency (CDF) of the AP1000 (Reference 2, Chapter 33). Therefore, relocating the normal residual heat removal system of the AP1000 inside containment will provide virtually no risk reduction benefit and will not be investigated further in terms of cost.

1B.1.4 Methodology

The severe accident mitigation design alternatives analysis uses a bounding methodology such that the benefit is conservatively maximized and the capital cost is conservatively minimized for each SAMDA.

1B.1.4.1 Total Population Dose

To assess the potential benefits associated with a design alternative, estimates are made of the offsite population doses resulting from each of the release categories (that is, source terms). MACCS2 version 1.12 (Reference 9) is used for the analysis. The NRC sponsored the development of this code. The code performs probabilistic estimates of offsite consequences from potential accidental releases in conformance with Chapter 9 of the probabilistic risk assessment guidelines described in NUREG/CR-2300 (Reference 10).

Doses are determined for the early exposure effects resulting from the initial 24 hours following the core damage initiation. The dose evaluation provides the conditional probability distributions for the consequence measures, which includes the whole-body dose for this analysis. These consequence probability distributions are based on the assumption that the accident that produced the source term has occurred. Therefore, the consequence probability distributions presented result from the variation in dose levels due to the various meteorological conditions. Hence, the actual probability of the identified dose levels would be the probability of the release category that produced the source term occurring multiplied by the probability of the dose level.

The dose risks are quantified by multiplying the calculated fission product release category frequency vector by the release category mean dose vectors. The frequencies for each of the six release categories are quantified in Chapter 45 of the AP1000 Probabilistic Risk Assessment (Reference 2), while the mean doses for each release category are identified in Chapter 49. Table 1B-1 presents the results of the dose risk calculations at the site boundary at 24 hours. The table presents the release category identifier, the release frequency (per reactor-year), the mean dose (in rem), and the resulting risk (in rem per reactor-year). In addition, each table presents the total dose risk and the percent that each release category contributes to the total risk.

It is shown that release category CFE presents the largest risk to the site safety.

The release categories for the AP1000 are defined as follows:

- IC – intact containment. Containment integrity is maintained throughout the accident, and the release of radiation to the environment is due to nominal leakage.

- CFE – containment failure early. Fission-product release through a containment failure caused by severe accident phenomenon occurring after the onset of core damage but prior to core relocation.

- CFI – containment failure intermediate. Fission-product release through a containment failure caused by severe accident phenomenon occurring after core relocation but before 24 hours.

- CFL – containment failure late. Fission-product release through a containment failure caused by severe accident phenomenon occurring after 24 hours.

- CI – containment isolation failure. Fission-product release through a failure of the system or valves that close the penetrations between the containment and the environment. Containment failure occurs prior to onset of core damage.

- BP – containment bypass. Fission products are released directly from the Reactor Coolant System to the environment via the secondary system or other interfacing system bypass. Containment failure occurs prior to onset of core damage.

The following subsections present a brief description of the AP1000 release categories.

Release Category IC – Intact Containment

If the containment integrity is maintained throughout the accident, then the release of radiation from the containment is due to nominal leakage and is expected to be within the design basis of the containment. This is the "no failure" containment failure mode and is termed intact containment. The main location for fission-product leakage from the containment is penetration leakage into the auxiliary building where significant deposition of aerosol fission products may occur.

Release Category CFE – Early Containment Failure

Early containment failure is defined as failure that occurs in the time frame between the onset of core damage and the end of core relocation. During the core melt and relocation process, several dynamic phenomena can be postulated to result in rapid pressurization of the containment to the point of failure. The combustion of hydrogen generated in-vessel, steam explosions, and reactor vessel failure from high pressure are major phenomena postulated to have the potential to fail the containment. If the containment fails during or soon after the time when the fuel is overheating and starting to melt, the potential for attenuation of the fission-product release diminishes because of short fission-product residence time in the containment. The fission products released to the containment prior to the containment failure are discharged at high pressure to the environment as the containment blows down. Subsequent release of fission products can then pass directly to the environment. Containment failures postulated within the time of core relocation are binned into release category CFE.

Release Category CFI – Intermediate Containment Failure

Intermediate containment failure is defined as failure that occurs in the time frame between the end of core relocation and 24 hours after core damage. After the end of the in-vessel fission-product release, the airborne aerosol fission products in the containment have several hours for deposition to attenuate the source term. The global combustion of hydrogen generated in-vessel from a random ignition prior to 24 hours can be postulated to fail the containment. The fission products in the containment atmosphere are discharged at high pressure to the environment as the containment blows down. Containment failures postulated within 24 hours of the onset of core damage are binned into release category CFI.

Release Category CFL – Late Containment Failure

Late containment failure is defined as containment failure postulated to occur later than 24 hours after the onset of core damage. Since the probabilistic risk assessment assumes the dynamic phenomena, such as hydrogen combustion, to occur before 24 hours, this failure mode occurs only from the loss of containment heat removal via failure of the passive containment cooling system. The fission products that are airborne at the time of containment failure will be discharged at high pressure to the environment, as the containment blows down. Subsequent release of fission products can then pass directly to the environment. Accident sequences with failure of containment heat removal are binned in release category CFL.

Release Category CI – Containment Isolation Failure

A containment isolation failure occurs because of the postulated failure of the system or valves that close the penetrations between the containment and the environment. Containment isolation failure occurs before the onset of core damage. For such a failure, fission-product releases from the reactor coolant system can leak directly from the containment to the environment with diminished potential for attenuation. Most isolation failures occur at a penetration that connects the containment with the auxiliary building. The auxiliary building may provide additional attenuation of aerosol fission-product releases. However, this decontamination is not credited in the containment isolation failure cases. Accident sequences in which the containment does not isolate prior to core damage are binned into release category CI.

Release Category BP – Containment Bypass

Accident sequences in which fission products are released directly from the reactor coolant system to the environment via the secondary system or other interfacing system bypass the containment. The containment failure occurs before the onset of core damage and is a result of the initiating event or adverse conditions occurring at core uncovery. The fission-product release to the environment begins approximately at the onset of fuel damage, and there is no attenuation of the magnitude of the source term from natural deposition processes beyond that which occurs in the reactor coolant system, in the secondary system, or in the interfacing system. Accident sequences that bypass the containment are binned into release category BP.

1B.1.4.2 AP1000 Risk (CDF, LRF, and POPULATION Dose)

Table 1B-2 presents a summary of the CDF and large release frequency (LRF) risks for the AP1000.

Level 3 analysis is performed only for internal events at power. The ensuing population dose was very low, and it was not pursued for other events. The population dose for internal events is given in Table 1B-3.

1B.1.5 Summary of Risk Significant Enhancements

This section summarizes the design enhancements already incorporated into the AP1000 plant due to probabilistic risk assessment insights and results.

- Changed normal position of the two containment motor-operated recirculation valves (in series with squib valves) from closed to open

  The normal position of the two motor-operated valve lines in the two sump recirculation lines has been changed from NORMALLY CLOSED to NORMALLY OPEN to improve the reliability of opening these paths. These two paths support containment recirculation for core cooling and IRWST draining for IVR. This change reduced the CDF and LRF contribution from the failure modes to open the motor-operated valves.

- Changed IRWST drain procedure so it occurs earlier for IVR support

  Credit is taken for operator action to drain the IRWST into the sump to preserve reactor vessel integrity following core melt. The procedure for this severe accident response has been modified so that the operator action associated with IRWST draining is moved to the beginning of the procedure to allow more time for operator success and also to fill the cavity as soon as possible. This improves the probability of success of the operator action.

- Improved IVR heat transfer

  In going from the AP600 to the AP1000, the heat loads during IVR are increased due to the larger core power level, which reduced the margins in the heat removal capability through the reactor vessel head during IVR. To compensate for the increase in core power, the critical heat flux limit on the outside of the reactor vessel has been increased by changes made to the flow path between the outside of the reactor vessel and the reactor vessel insulation. Testing has confirmed the robustness of the IVR heat transfer.

- Improved IRWST vents

  The larger core in the AP1000 can generate more hydrogen in a severe accident. In the AP1000 hydrogen analysis for Level II, it was observed that the standing hydrogen diffusion flames at the IRWST vents resulted in a larger thermal loads to the containment steel shell, potentially leading to containment wall failure. The design of the vents was changed so that the IRWST vents located well away from the containment would open and the IRWST vents located next to the containment would not open during a severe accident to eliminate or minimize this potential concern.

- Incorporated low boron core (anticipated transients without scram)

  In the AP600, anticipated transients without scram (ATWS) contribution to LRF was noticed to be high relative to other initiating events. A low boron core was incorporated into the design to reduce the potential contribution of ATWS to plant risk.

- Added 3rd passive containment cooling drain valve (motor-operator valve diverse to air-operated valve)

  Due to reduced containment surface area per MW of core power, natural air circulation without passive containment cooling system water drain may not always be sufficient for long-term (greater than 1 day) containment heat removal in the AP1000. For the AP600, it was always sufficient for an indefinite time. To reduce the uncertainty in whether air cooling is sufficient to provide adequate long-term containment heat removal, a third path was added to the passive containment cooling system drain lines to increase passive containment cooling system reliability. The isolation valve used in the third path is a motor-operated valve, which is diverse from the air-operated valves used in the other two lines. This provides considerable improvement in the passive containment cooling system water drain reliability.

- Reduced potential recirculation-line squib valve failures

  An examination of AP1000 plant CDF cutsets revealed that the common cause failure of 4/4 recirculation line squib valves is a dominant contributor to CDF and LRF. This failure mode can be reduced by re-aligning the diverse squib valves already used in the AP1000 (and AP600) IRWST injection paths (high-pressure valves) and the containment recirculation paths (low-pressure valves). By making the recirculation squib valves two sets of two low-pressure and high-pressure squib valves, which are different and belong to different common cause failure groups. This design change reduces the common cause failure contribution of the recirculation squib valves. The increase in the group size of the high-pressure squib valves from four to six (including the four from the IRWST injection lines) does not add an appreciable contribution to the plant CDF.

1B.1.6 Specific Site Characteristics

AP1000 Probabilistic Risk Assessment Chapter 49, “Offsite Dose Risk Quantification,” is based on an Electric Power Research Institute (EPRI) report (Reference 11) to establish the specific site characteristics for AP1000. Reference 11 Annex B, “ALWR Reference Site,” establishes a conservative reference site to represent the consequences of most potential sites with respect to exposure at the site boundary. This reference site was based on the characteristics of 91 U.S. reactor sites that are tabulated in the NRC document, “Technical Guidance for Siting Criteria Development,” (NUREG CR-2239) (Reference 12). Annex B provides a summary of the meteorological data to be used in calculating offsite dose.

1B.1.7 Value of Eliminating Risk

The cost benefit methodology of NUREG/BR-0184 (1997) is used to calculate the maximum attainable benefit. This includes replacement power costs. The maximum improvement change in the CDF frequency (delta-F) is assumed to be equal to the sum of CDF frequencies from internal, external, and shutdown events that are already evaluated:

delta F = 5 E-07/year

This is bounding and is used to calculate the maximum attainable benefit. In practice, there is no design alternative, or SAMDA strategy, whose implementation would reduce the plant CDF to zero (or to an infinitesimally small frequency).

PRA Table 49-10, Revision 4, is used to calculate the expected value of the person-rem exposure:

Dose = 179,000 person-rem (0.0432 / 2.41E-07, from Table 49-10)

It is assumed that this dose is applicable to all events (internal, external, at-power, and shutdown). Thus, the consequences (dose and other) from all events are included in the calculations. Uncertainty in this dose is analyzed in sensitivity case 2 given below.

The following cost categories are investigated (NUREG/BR-0184 notation is used):

C1	Public Health (Accident)		5.7.1	5.7.1.3	W(pha)
C2	Public Health (Routine)		5.7.2	5.7.2	V(phr)
C3	Occupational Health (Accident)	Sum of C4 and C5	5.7.3	5.7.3	V(oha)
C4		Accident Related Exposure - ID		5.7.3.3	W(io)
C5		LT Doses		5.7.3.3	W(lto)
C6	Occupational Health (Routine)		5.7.4	5.7.4	V(ohr)
C7	Offsite Property		5.7.5	5.7.5	V(fp)
C8	Onsite Property	Sum of C9, C10, and C11	5.7.6	5.7.6	V(op)
C9		Cleanup and Decon		5.7.6.1	U(cd)
C10		LT Replacement Power		5.7.6.2	U(rp)
C11		Repair and Refurbishment		5.7.6.3	

The present-dollar value equivalent for severe accidents at one unit of the AP1000 is the sum of the offsite exposure costs, offsite economic costs, onsite exposure costs, and onsite economic costs. The present-day value (at 7-percent discount rate) of eliminating all plant CDF (maximum attainable benefit) is calculated to be $21,000, which is a very small dollar value. Thus, any mitigating system or a SAMDA strategy/alternative that reduces the plant risk by a fraction of the total plant CDF must cost less than $21,000 to be cost-effective.

Another calculation of the maximum attainable benefit is made with the discount rate of 3 percent (Table 7-2). The resulting value is $43,000, which is still very small to justify any appreciable investment.

Even if a very conservative multiplicative error factor of 10 were used, the maximum attainable benefit would be limited to a cost below $207,000.

Table 1B-4 summarizes the results of the base case and the sensitivity cases.

In all cases, the values are strongly affected (increased) because of the replacement power cost. This is an inappropriate bias for public decision making, since it does not relate to public safety and it is not a direct cost to the public since the costs are to the utility, and their impact on the electricity rates for the public is unpredictable.

The first sensitivity case is already discussed above. In the second sensitivity case, the dose values are increased (10 times for external, NUREG high-estimates for occupational health). The third sensitivity analysis acknowledges that the delta-F realistically cannot be equal to the total plant CDF; a factor of 0.5 is introduced.

Sensitivity case 4 examines the case where the CDF value (thus the delta-F) is increased by a factor of 2. Finally, sensitivity case 5 looks at what happens if a multiplicative error factor of 10 is applied to the base case. In all cases, the benefits range from very small to modest.

1B.1.8 Evaluation of Potential Improvements

The value of eliminating AP1000 total risk is $21,000, as discussed in Section 1B.1.7. This value is an upper bound for any single engineered design alternative, which would actually reduce CDF and/or LRF a fraction of the values assumed in the base case for calculating the $21,000 value.

For the AP1000, SAMDA design alternatives discussed in this section are found to be not cost effective. One of these alternatives is actually implemented in the AP1000 design (diverse containment recirculation squib valves) to help improve the success likelihood of cavity reflooding operator action in severe accidents. The costs associated with the remaining SAMDA design alternatives are provided in Table 1B-5. Only one design alternative, 3 – namely, self-actuating containment isolation valves – has a cost near $30,000; the remaining alternatives are at least an order of magnitude more costly than $30,000. Thus, only design alternative 3 needs to be further discussed.

1B.1.8.1 Self-Actuating Containment Isolation Valves

This SAMDA consists of improved containment isolation provisions on all normally open containment penetrations. The category of "normally open" is limited to normally open pathways to the environment during power and shutdown conditions, excluding closed systems inside and outside the containment such as normal residual heat removal system and component cooling. The design alternative would be to add a self-actuating valve or enhance the existing inside containment isolation valve to provide for self-actuation in the event that containment conditions are indicative of a severe accident. Conceptually, the design would either be an independent valve or an appendage to an existing fail-closed valve that would respond to post-accident containment

conditions within containment. For example, a fusible link would melt in response to elevated ambient temperatures resulting in venting the air operator of a fail-closed valve. This provides the self-actuating function. To evaluate the benefit of this SAMDA, this design change is assumed to eliminate the CI release category. This does not include induced containment failures, which occur at the time of the accident such as in cases of vessel rupture or ATWS. This design alternative provides almost no benefit in reducing plant CDF.

Generously assuming that this design alternative will eliminate CI release totally and that Delta CDF is zero, the benefit of this design alternative is calculated to be at the order of a few thousand dollars. Thus, even the cheapest design alternative does not meet the benefit/cost ratio of 1.

1B.1.8.2 Other New Design Changes

Other design changes, as discussed in Section 1B.1.5, are already incorporated into the AP1000. There is no cost/benefit analysis available for those changes already incorporated.

Two additional design changes not incorporated in the AP1000 were assessed as follows:

Larger Accumulators

Increasing the size of the accumulators would result in a significant increase in cost that would be greater than the cost threshold established by the perfect SAMDA evaluation. In order to have any benefit in the probabilistic risk assessment, the accumulators would have to be increased in size sufficiently to change the large LOCA success criteria from two of two accumulators to one of two accumulators. Westinghouse estimates that the accumulator tanks would have to be increased in size from 2000 ft^3 to 4000 ft^3, and the hardware costs associated with this change would be significant. Such a size increase would also likely result in a change to the design of the DVI piping subsystem. The design of this piping system was established in the AP600 design certification, and the design does not change significantly for AP1000. Recently, Westinghouse completed the leak-before break analysis of the DVI piping, and any change in the DVI piping would result in significant piping reanalysis of the DVI piping. Westinghouse estimates the redesign costs associated with the changes in hardware and piping re-design to be significantly greater than the cost threshold established for the perfect SAMDA discussed above. Therefore this design change was not incorporated.

Larger Fourth-Stage ADS Valves

Increasing the fourth-stage ADS valves in size would result in a significant increase in cost associated with redesigning the AP1000 loop piping and fourth-stage piping configuration. The AP1000 ADS valves were already increased in size compared to the AP600 valves more than the ratio of the power uprate of the AP1000. In order to have any benefit in the probabilistic risk assessment, the 4th stage ADS valves would have to be increased in size sufficiently to change the LOCA success criteria from three of four valves to two of four valves. To accommodate such a change, Westinghouse estimates that the fourth-stage ADS valves would have to increase in size from 14-inch to 18-inch valves and associated piping. In addition, the common fourth-stage inlet piping that connects to the hot leg would have to increase in size from 18-inch to at least 20-inch. This would require a significant redesign of the squib valve and would also result in redesign of

the ADS-4 piping which in turn would impact the design of the reactor coolant loop piping. Finally, such a redesign would require Westinghouse to perform additional confirmatory testing of the passive core cooling system to verify that the behavior of the passive safety systems was not adversely impacted. Westinghouse estimates the cost of this change to be significantly larger than the cost threshold of the perfect SAMDA discussed above. Therefore, this design change was not incorporated.

1B.1.9 Results

Due to the existing low risk of the AP1000 plant, none of the design alternatives described in Section 1B.1.3 meet an acceptable benefit to cost ratio of 1 or greater.

Several of the design alternatives evaluated in other SAMDA analyses are included in the current AP1000 design. These design features include the following:

- Reactor coolant system depressurization system
- Passive residual heat removal system located inside containment
- Cavity flooding system
- Passive containment cooling system
- Hydrogen igniters in a large-dry containment
- Diverse actuation system
- Canned motor reactor coolant pumps
- Interfacing system with high design pressure

As the AP1000 plant CDF is lower than for existing plants, the benefits of additional design alternatives are small. The SAMDAs analyzed provided little or no benefit to the AP1000 design.

Assuming a hypothetical design alternative was developed which provides a 100-percent reduction in overall plant risk, representing an average averted risk of 4.32×10^{-2} man-rem per year, the capital benefit amounts to only $21,000.

1B.2 References

1. “SECY-91-229 - Severe Accident Mitigation Design Alternatives for Certified Standard Designs,” USNRC Memorandum from Samuel J. Chilk to James M. Taylor, dated October 25, 1991.

2. “AP1000 Probabilistic Risk Assessment,” APP-GW-GL-022, Revision 5, Westinghouse Electric Company, December 2003.

3. “AP600 Probabilistic Risk Assessment,” Westinghouse Electric Corporation and ENEL, Revision 8, September 1996.

4. “Supplement to the Final Environmental Statement - Limerick Generating Station, Units 1 and 2,” Docket Nos. 50-352/353, August 1989.

5. "Supplement to the Final Environmental Statement - Comanche Peak Steam Electric Station, Units 1 and 2," Docket Nos. 50-445/446, October 1989.

6. "System 80+ Design Alternatives Report," Docket No. 52-002, April 1992.

7. "Technical Assessment Guide," EPRI P-6587-L, Volume 1, Revision 6, September 1989.

8. Nuclear Energy Cost Data Base, DOE/NE-0095, U.S. Department of Energy, September 1988.

9. Chanin, D., Young, M. L., "Code Manual for MACCS2, User's Guide," NUREG/CR-6613, SAND97-0594, Vol. 1, Sandia National Laboratories, U.S. Nuclear Regulatory Commission.

10. "PRA Procedures Guide," NUREG/CR-2300, U.S. Nuclear Regulatory Commission, Vol. 2, Chapter 9, Washington, D.C.

11. EPRI Advanced Light Water Reactor Utility Requirements Document Volume III Annex B "ALWR Reference Site," Revisions 5 & 6, December 1993.

12. NRC NUREG/CR-2239 "Technical Guidance for Siting Criteria Development," prepared by Sandia National Laboratories, D.C. Aldrich, et al., December 1982.

Table 1B-1

POPULATION WHOLE BODY EDE DOSE RISK – 24 HOURS

Release Category	Release Frequency (per reactor year)	Mean Dose (person-sieverts)	Dose (person-REM)	Risk (person-REM per reactor year)	Percentage Contribution to Total Risk
CFI	1.89E-10	7.03E+03	7.03E+05	1.33E-04	0.3
CFE	7.47E-09	8.51E+03	8.51E+05	6.36E-03	14.7
IC	2.21E-07	7.19E+00	7.19E+02	1.59E-04	0.4
BP	1.05E-08	3.23E+04	3.23E+06	3.39E-02	78.4
CI	1.33E-09	2.01E+04	2.01E+06	2.67E-03	6.2
CFL	3.45E-13	7.37E+01	7.37E+03	2.54E-09	0.0
			Total Risk =	4.32E-02	100.0

Table 1B-2

SUMMARY OF AP1000 PRA RESULTS (CDF AND LRF)

Events	Core Damage Frequency (per year)		Large Release Frequency (per year)	
	At-Power	**Shutdown**	**At-Power**	**Shutdown**
Internal Events	2.41E-07	1.23E-07	1.95E-08	2.05E-08
Internal Flood	8.82E-10	3.22E-09	7.14E-11	5.37E-10
Internal Fire	5.61E-08	8.5E-08	4.54E-09	1.43E-08
Sum =	2.97E-07	2.11E-07	2.41E-08	3.53E-08

Note:
For seismic risk, the seismic margins method is used. CDF and LRF are not quantified.

Table 1B-3

POPULATION WHOLE BODY DOSE (EFFECTIVE DOSE EQUIVALENT [EDE]), 0-80.5 KM PERSON-SIEVERTS

24-Hour Case Source Term	Quantiles						Peak Consequence
	Mean	50th	90th	95th	99th	99.5th	
CFI	7.03E+03	5.33E+03	1.31E+04	1.82E+04	3.11E+04	3.59E+04	5.07E+04
CFE	8.51E+03	6.25E+03	1.62E+04	2.31E+04	4.13E+04	5.06E+04	6.40E+04
DIRECT	2.16E+01	1.20E+01	4.78E+01	8.13E+01	1.14E+02	1.23E+02	1.68E+02
IC	7.19E+00	4.21E+00	1.71E+01	2.95E+01	3.56E+01	3.84E+01	5.60E+01
BP	3.23E+04	2.10E+04	6.40E+04	1.03E+05	1.54E+05	1.82E+05	2.64E+05
CI	2.01E+04	1.13E+04	4.71E+04	6.60E+04	1.23E+05	1.48E+05	1.61E+05
CFL	7.37E+01	1.00E+01	1.62E+02	5.91E+02	9.76E+02	1.11E+03	2.56E+03
72-Hour Case Source Term	**Quantiles**						**Peak Consequence**
	Mean	**50th**	**90th**	**95th**	**99th**	**99.5th**	
CFI	1.13E+04	9.02E+03	2.12E+04	2.63E+04	4.09E+04	4.89E+04	6.18E+04
CFE	9.36E+03	6.89E+03	1.898E+04	2.54E+04	4.25E+04	5.12E+04	6.77E+04
DIRECT	2.36E+01	1.35E+01	5.28E+01	8.32E+01	1.15E+02	1.25E+02	1.75E+02
IC	7.87E+00	4.75E+00	1.85E+01	3.00E+01	3.79E+01	4.20E+01	5.83E+01
BP	4.17E+04	2.94E+04	7.99E+04	1.16E+05	2.20E+05	2.61E+05	2.87E+05
CI	2.14E+04	1.25E+04	4.90E+04	7.40E+04	1.27E+05	1.53E+05	1.67E+05
CFL	4.79E+04	3.11E+04	9.57E+04	1.57E+05	2.62E+05	3.01E+05	4.14E+05

Table 1B-4

COST BENEFIT CALCULATION RESULTS FOR DIFFERENT ASSUMPTIONS

	Case Studied	Benefit of Case
Base Case	7% Discount rate	21,000
SC-1	3% Discount rate	43,000
SC-2	High dose (10 times the base case)	36,000
SC-3	Realistic delta-F (SAMDA reduces CDF by 50% of total)	10,000
SC-4	Twice the base CDF	41,000
SC-5	10 times the benefit of base case	207,000

Table 1B-5

DESIGN ALTERNATIVES FOR SAMDA

No.	Design Alternative	Cost
1	Upgrade chemical, volume, and control system for small LOCA	1,500,000
2	Containment filtered vent	5,000,000
3	Self-actuating containment isolation valves	33,000
4	Safety grade passive containment spray	3,900,000
6	Steam generator shell-side heat removal	1,300,000
7	Steam generator relief flow to IRWST	620,000
8	Increased steam generator pressure capability	8,200,000
9	Secondary containment ventilation with filtration	2,200,000
10	Diverse IRWST injection valves	570,000
11	Diverse containment recirculation valves	Already Implemented
12	Ex-vessel core catcher	1,660,000
13	High-pressure containment design	50,000,000
14	More reliable diverse actuation system	470,000

TABLE OF CONTENTS

LIST OF TABLES

CHAPTER 2

SITE CHARACTERISTICS

This chapter defines the site-related parameters for which the AP1000 plant is designed. The site parameters are in Table 2-1. These parameters envelope most potential sites in the United States. The sections of this chapter follow the standard format and discuss how the specific parameters are used in the AP1000 design and how the Combined License applicant is to demonstrate that the site meets the design parameters.

The site is acceptable if the site characteristics fall within the AP1000 plant site design parameters in Table 2-1. Should specific site parameters or characteristics be outside the envelope of assumptions established by Table 2-1, the Combined License applicant referencing the AP1000 will demonstrate that the design satisfies the requirements imposed by the specific site parameters and conforms to the design commitments and acceptance criteria described in the AP1000 Design Control Document.

2.1 Geography and Demography

The geography and demography are site specific and will be defined by the Combined License applicant.

2.1.1 Combined License Information for Geography and Demography

Combined License applicants referencing the AP1000 certified design will provide site-specific information related to site location and description, exclusion area authority and control, and population distribution.

Site Information – Site-specific information on the site and its location will include political subdivisions, natural and man-made features, population, highways, railways, waterways, and other significant features of the area.

Exclusion Area – Site-specific information on the exclusion area will include the size of the area and the exclusion area authority and control. Activity that may be permitted within the exclusion area will be included in the discussion.

Population Distribution – Site-specific information will be included on population distribution.

2.2 Nearby Industrial, Transportation, and Military Facilities

The plant has inherent capability to withstand certain types of external accidents due to the specified design conditions associated with earthquakes, wind loading, and radiation shielding. Acceptability for external accidents associated with a given site will be covered in the Combined License application.

Each Combined License applicant referencing the AP1000 will provide analyses of accidents external to the nuclear plant. The determination of the probability of occurrence of potential accidents which could have severe consequences will be based on analyses of available statistical

data on the occurrence of the accident together with analyses of the effects of the accident on the plant's safety-related structures and components. If an accident is identified for which the probability of severe consequences is unacceptable, specific changes to the AP1000 will be identified in the Combined License safety analysis report. The criteria for not requiring changes to the AP1000 design is that the total annual frequency of occurrence is less than 10^{-6} per year for an external accident leading to severe consequences. The following accident categories will be considered in determining the frequency of occurrence, as appropriate:

Explosions – Accidents involving detonations of high explosives, munitions, chemicals, or liquid and gaseous fuels will be considered for facilities and activities in the vicinity of the plant where such materials are processed, stored, used, or transported in quantity.

Flammable Vapor Clouds (Delayed Ignition) – Accidental releases of flammable liquids or vapors that result in the formation of unconfined vapor clouds in the vicinity of the plant.

Toxic Chemicals – Accidents involving the release of toxic chemicals from nearby mobile and stationary sources.

Fires – Accidents leading to high heat fluxes or smoke, and to nonflammable gas or chemical-bearing clouds from the release of materials as the consequence of fires in the vicinity of the plant.

Airplane Crashes – Accidents involving aircraft crashes leading to missile impact or fire in the vicinity of the plant.

2.2.1 Combined License Information for Identification of Site-specific Potential Hazards

Combined License applicants referencing the AP1000 certified design will provide site-specific information related to the identification of potential hazards within the site vicinity, including an evaluation of potential accidents and verify that the frequency of site-specific potential hazards is consistent with the criteria outlined in Section 2.2. The site-specific information will provide a review of aircraft hazards, information on nearby transportation routes, and information on potential industrial and military hazards.

2.3 Meteorology

The AP1000 is designed for air temperatures, humidity, precipitation, snow, wind, and tornado conditions as specified in Table 2-1. The Combined License applicant must provide information to demonstrate that the site parameters are within the limits specified for the standard design.

The design wind is specified as a basic wind speed of 145 mph with an annual probability of occurrence of 0.02. Wind loads are calculated for exposure C, which is applicable to shorelines in hurricane prone areas. The site parameters for the design wind may be demonstrated to be acceptable for other exposures or topographic factors by comparison of the wind loads on the structures. For example, for a site at a location with exposure Category D, the wind speed should be equal to or less than 130 mph.

2.3.1 Regional Climatology

The regional climatology is site specific and will be defined by the Combined License applicant.

2.3.2 Local Meteorology

The local meteorology is site specific and will be defined by the Combined License applicant.

2.3.3 Onsite Meteorological Measurement Programs

The onsite meteorological measurement program is site specific and will be defined by the Combined License applicant. The number and location of meteorological instrument towers are determined by actual site parameters.

2.3.4 Short-Term Diffusion Estimates

In the absence of a specific site for use in determining values for short-term diffusion, a study was performed to determine the atmospheric dispersion factors (χ/Q values) that would envelope most current plant sites and that could be used to calculate the radiological consequences of design basis accidents. The χ/Q values thus derived for offsite are provided in Table 2-1.

This set of offsite χ/Q values is representative of potential sites for construction of the AP1000. The values are appropriate for analyses to determine the radiological consequences of accidents. These values were selected to bound 70 to 80 percent of U.S. sites.

The χ/Q values for the control room air intake or the door leading to the control room are dependent not only on the site meteorology but also on the plant design and layout. These χ/Q values are addressed in Appendix 15A. Separate sets of χ/Q values are identified for each combination of activity release location and receptor location.

2.3.5 Long-Term Diffusion Estimates

The long-term diffusion estimates are site specific and will be provided by the Combined License applicant. The site boundary annual average χ/Q shown in Table 2-1 is used to calculate release concentrations at the site boundary for comparison with the activity release limits defined in 10 CFR 20. The value specified is expected to bound atmospheric conditions at most U.S. sites. If a selected site has a χ/Q value that exceeds this reference site value, the release concentrations reported in Section 11.3 would be adjusted proportionate to the change in χ/Q.

2.3.6 Combined License Information

2.3.6.1 Regional Climatology

Combined License applicants referencing the AP1000 certified design will address site-specific information related to regional climatology.

2.3.6.2 Local Meteorology

Combined License applicants referencing the AP1000 certified design will address site-specific local meteorology information.

2.3.6.3 Onsite Meteorological Measurements Program

Combined License applicants referencing the AP1000 certified design will address the site-specific onsite meteorological measurements program.

2.3.6.4 Short-Term Diffusion Estimates

Combined License applicants referencing the AP1000 certified design will address the site-specific χ/Q values specified in subsection 2.3.4. For a site selected that exceeds the bounding χ/Q values, the Combined License applicant will address how the radiological consequences associated with the controlling design basis accident continue to meet the dose reference values given in 10 CFR Part 50.34 and control room operator dose limits given in General Design Criteria 19 using site-specific χ/Q values. The Combined License applicant should consider topographical characteristics in the vicinity of the site for restrictions of horizontal and/or vertical plume spread, channeling or other changes in airflow trajectories, and other unusual conditions affecting atmospheric transport and diffusion between the source and receptors. No further action is required for sites within the bounds of the site parameters for atmospheric dispersion.

With regard to assessment of the postulated impact of an accident on the environment, the COL applicant will provide χ/Q values for each cumulative frequency distribution which exceeds the median value (50 percent of the time).

2.3.6.5 Long-Term Diffusion Estimates

Combined License applicants referencing the AP1000 certified design will address long-term diffusion estimates and χ/Q values specified in subsection 2.3.5. The Combined License applicant should consider topographical characteristics in the vicinity of the site for restrictions of horizontal and/or vertical plume spread, channeling or other changes in airflow trajectories, and other unusual conditions affecting atmospheric transport and diffusion between the source and receptors. No further action is required for sites within the bounds of the site parameter for atmospheric dispersion.

With regard to environmental assessment, the COL applicant will also provide estimates of annual average χ/Q values for 16 radial sectors to a distance of 50 miles from the plant.

2.4 Hydrologic Engineering

The AP1000 is designed for a normal groundwater elevation up to plant elevation 98′ and for a flood level up to plant elevation 100′. For structural analysis purposes, grade elevation is also established as plant elevation 100′. Actual grade will be a few inches lower to prevent surface water from entering doorways.

For a portion of the annex building the site grade will be 107 feet to permit truck access at the elevation of the floor in the annex building and inside containment. Subsection 3.4.1 describes design provisions for groundwater and flooding.

The Combined License applicant will evaluate events leading to potential flooding to demonstrate that the site meets the site parameter for flood level. As necessary, the Combined License applicant may propose measures to protect the plant according to the Standard Review Plan, Section 2.4.10. Events to be considered are those identified in Standard Review Plan, Section 2.4.2.

Adverse effects of flooding due to high water or ice effects do not have to be considered for site-specific nonsafety-related structures and water sources outside the scope of the certified design. Flooding of water intake structures, cooling canals, or reservoirs or channel diversions would not prevent safe operation of the plant.

2.4.1 Combined License Information

2.4.1.1 Hydrological Description

Combined License applicants referencing the AP1000 certified design will describe major hydrologic features on or in the vicinity of the site including critical elevations of the nuclear island and access routes to the plant.

2.4.1.2 Floods

Combined License applicants referencing the AP1000 certified design will address the following site-specific information on historical flooding and potential flooding factors, including the effects of local intense precipitation.

- Probable Maximum Flood on Stream and Rivers – Site-specific information that will be used to determine the design basis flooding at the site. This information will include the probable maximum flood on streams and rivers.

- Dam Failures – Site-specific information on potential dam failures.

- Probable Maximum Surge and Seiche Flooding – Site-specific information on probable maximum surge and seiche flooding.

- Probable Maximum Tsunami Loading – Site-specific information on probable maximum tsunami loading.

- Flood Protection Requirements – Site-specific information on flood protection requirements or verification that flood protection is not required to meet the site parameter for flood level.

No further action is required for sites within the bounds of the site parameter for flood level.

2.4.1.3 Cooling Water Supply

Combined License applicants will address the water supply sources to provide makeup water to the service water system cooling tower.

2.4.1.4 Groundwater

Combined License applicants referencing the AP1000 certified design will address site-specific information on groundwater. No further action is required for sites within the bounds of the site parameter for ground water.

2.4.1.5 Accidental Release of Liquid Effluents in Ground and Surface Water

Combined License applicants referencing the AP1000 certified design will address site-specific information on the ability of the ground and surface water to disperse, dilute, or concentrate accidental releases of liquid effluents. Effects of these releases on existing and known future use of surface water resources will also be addressed.

2.4.1.6 Emergency Operation Requirement

Combined License applicants referencing the AP1000 certified design will address any flood protection emergency procedures required to meet the site parameter for flood level.

2.5 Geology, Seismology, and Geotechnical Engineering

Combined License applicants referencing the AP1000 certified design will address site specific information related to basic geological, seismological, and geotechnical engineering of the site and the region, as discussed in the following subsections.

2.5.1 Basic Geological and Seismic Combined License Information

Combined License applicants referencing the AP1000 certified design will address the following regional and site-specific geological, seismological, and geophysical information as well as conditions caused by human activities:

- Structural geology of the site
- Seismicity of the site
- Geological history
- Evidence of paleoseismicity
- Site stratigraphy and lithology
- Engineering significance of geological features
- Site groundwater conditions
- Dynamic behavior during prior earthquakes
- Zones of alteration, irregular weathering, or structural weakness
- Unrelieved residual stresses in bedrock
- Materials that could be unstable because of mineralogy or unstable physical properties
- Effect of human activities in the area

2.5.2 Vibratory Ground Motion

The AP1000 is designed for a safe shutdown earthquake (SSE) defined by a peak ground acceleration (PGA) of 0.30g and the design response spectra specified in subsection 3.7.1.1, and Figures 3.7.1-1 and 3.7.1-2. The AP1000 design response spectra were developed using the Regulatory Guide 1.60 response spectra as the base and modified to address high frequency amplification effects observed in eastern North America earthquakes. The peak ground accelerations in the two horizontal and the vertical directions are equal.

2.5.2.1 Combined License Seismic and Tectonic Characteristics Information

Combined License applicants referencing the AP1000 certified design will address the following site-specific information related to the vibratory ground motion aspects of the site and region:

- Seismicity
- Geologic and tectonic characteristics of site and region
- Correlation of earthquake activity with seismic sources
- Probabilistic seismic hazard analysis and controlling earthquakes
- Seismic wave transmission characteristics of the site
- SSE ground motion

The Combined License applicant must demonstrate that the proposed site meets the following requirements:

- The free field peak ground acceleration at the foundation level is less than or equal to a 0.30g SSE.

- The site design response spectra at the foundation level in the free-field are less than or equal to those given in Figures 3.7.1-1 and 3.7.1-2.

2.5.2.2 Site-Specific Seismic Structures

The AP1000 includes all seismic Category I structures, systems and components in the scope of the design certification.

2.5.2.3 Sites with Geoscience Parameters Outside the Certified Design

If the site-specific spectra at foundation level exceed the response spectra in Figures 3.7.1-1 and 3.7.1-2 at any frequency, or if soil conditions are outside the range evaluated for AP1000 design certification, a site-specific evaluation can be performed. This evaluation will consist of a site-specific dynamic analysis and generation of in-structure response spectra to be compared with the floor response spectra of the certified design at 5-percent damping. The site design response spectra at the foundation level in the free-field given in Figures 3.7.1-1 and 3.7.1-2 were used to develop the floor response spectra. The site is acceptable for construction of the AP1000 if the

floor response spectra from the site-specific evaluation do not exceed the AP1000 spectra for each of the locations identified below:

• Reactor vessel support	Figure 3.7.2-17, Sheets 1–3
• Containment operating floor	Figure 3.7.2-17, Sheets 4–6
• Coupled auxiliary and shield building at control room floor	Figure 3.7.2-15, Sheets 1–3
• Coupled auxiliary and shield building at fuel building roof	Figure 3.7.2-15, Sheets 4–6
• Coupled auxiliary and shield building at shield building roof	Figure 3.7.2-15, Sheets 13–15
• Steel containment vessel at polar crane support	Figure 3.7.2-16, Sheets 1–3

Site-specific soil structure interaction analyses must be performed by the Combined License applicant to demonstrate acceptability of sites that have seismic and soil characteristics outside the site parameters in Table 2-1. These analyses would use the site-specific soil conditions (including variation in soil properties in accordance with Standard Review Plan 3.7.2). The three components of the site-specific ground motion time history must satisfy the enveloping criteria of Standard Review Plan 3.7.1 for the response spectrum for damping values of 2, 3, 4, 5, and 7 percent and the enveloping criterion for power spectral density function. Floor response spectra determined from the site-specific analyses should be compared against the design basis of the AP1000 described above. Member forces in each of the sticks should be compared against those given in Tables 3.7.2-11 to 3.7.2-13. These evaluations and comparisons will be provided and reviewed as part of the Combined License application.

2.5.3 Surface Faulting Combined License Information

Combined License applicants referencing the AP1000 certified design will address the following surface and subsurface geological, seismological, and geophysical information related to the potential for surface or near-surface faulting affecting the site:

- Geological, seismological, and geophysical investigations
- Geological evidence, or absence of evidence, for surface deformation
- Correlation of earthquakes with capable tectonic sources
- Ages of most recent deformation
- Relationship of tectonic structures in the site area to regional tectonic structures
- Characterization of capable tectonic sources
- Designation of zones of quaternary deformation in the site region
- Potential for surface tectonic deformation at the site

2.5.4 Stability and Uniformity of Subsurface Materials and Foundations

Combined License applicants referencing the AP1000 certified design will address the following site-specific information related to the stability and uniformity of subsurface materials and foundations.

- Excavation
- Bearing capacity
- Settlement
- Liquefaction

Seismic analysis and foundation design for rock sites is described in Sections 3.7 and 3.8. The AP1000 certified design is based on the nuclear island being founded on rock. Soils may be present above the foundation level.

2.5.4.1 Excavation

Excavation in soil for the nuclear island structures below grade will establish a vertical face with lateral support of the adjoining undisturbed soil or rock. One alternative is to use a soil nailing method. Soil nailing is a method of retaining earth in-situ. As the nuclear island excavation progresses vertically downward, holes are drilled horizontally into the adjoining undisturbed soil, a metal rod is inserted into the hole, and grout is pumped into each hole to fill the hole and to anchor the "nail" rod.

As each increment of the nuclear island excavation is completed, nominal eight to ten inch diameter holes are drilled horizontally through the vertical face of the excavation into adjacent undisturbed soil. These "nail" holes, spaced horizontally and vertically on five to six feet centers, are drilled slightly downward to the horizontal. A "nail", normally a metal bar/rod, is center located for the full length of the hole. The nominal length of soil nails is 60 percent to 70 percent of the wall height, depending upon soil conditions. The hole is filled with grout to anchor the rod to the soil. A metal face plate is installed on the exposed end of the rod at the excavated wall vertical surface. Welded wire mesh is hung on the wall surface for wall reinforcement and secured to the soil nail face plates for anchorage. A 4,000 psi to 5,000 psi non-expansive pea gravel shotcrete mix is blown onto the wire mesh to form a nominal four to six inch thick soil retaining wall. Installation of the soil retaining wall closely follows the progress of the excavation and is from the top down, with each wire mesh-reinforced, shotcreted wall section being supported by the soil "nails" and the preceding elevations of soil nailed wall placements. The shotcrete contains a crystalline waterproofing material as described in subsection 3.4.1.1.1.

Soil nailing as a method of soil retention has been successfully used on excavations up to 55 feet deep on projects in the U.S. Soils have been retained for up to 90 feet in Europe. The state of California CALTRANS uses soil nailing extensively for excavations and soil retention installations. Soil nailing design and installation has a successful history of application which is evidenced by its excellent safety record.

The soil nailing method produces a vertical surface down to the bottom of the excavation and is used as the outside forms for the exterior walls below grade of the nuclear island. Concrete is placed directly against the vertical concrete surface of the excavation.

For excavation in rock and for methods of soil retention other than soil nailing, four to six inches of shotcrete are blown on to the vertical surface. The concrete for the exterior walls is placed against the shotcrete. The shotcrete contains a crystalline waterproofing material as described in subsection 3.4.1.1.1.

2.5.4.2 Bearing Capacity

The maximum bearing reaction on the hard rock determined from the analyses described in subsection 3.8.5.1 is less than 120,000 lb/ft^2 under all combined loads, including the safe shutdown earthquake. The allowable bearing capacity at a hard rock site will exceed this demand.

The maximum bearing reaction on the hard rock specified in Table 2-1 is determined from the analyses described in subsection 3.8.5.1. The evaluation of the allowable capacity of the bedrock should be based on the properties of the underlying materials (see subsection 2.5.4.5.2), including appropriate laboratory test data to evaluate strength, and considering local site effects, such as fracture spacing, variability in properties, and evidence of shear zones. The allowable bearing capacity should provide a factor of safety appropriate for the design load combination, including safe shutdown earthquake loads.

If the shear wave velocity or the allowable bearing capacity is outside the range evaluated for AP1000 design certification, a site-specific evaluation can be performed using the AP1000 basemat model and methodology described in subsection 3.8.5. The safe shutdown earthquake loads are those from the AP1000 analyses described therein. Alternatively, bearing pressures may be determined from a site-specific analysis using site-specific inputs as described in subsection 2.5.2.3. For the site to be acceptable, the bearing pressures from the site-specific analyses, including static and dynamic loads, need to be less than the capacity of each portion of the basemat.

2.5.4.3 Settlement

Settlement at a hard rock site is small and is not significant to the design of the AP1000. The AP1000 does not rely on structures, systems, or components located outside the nuclear island to provide safety-related functions. Differential settlement between the nuclear island foundation and the foundations of adjacent buildings does not have an adverse effect on the safety-related functions of structures, systems, and components. Differential settlement under the nuclear island foundation could cause the basemat and buildings to tilt. Much of this settlement occurs during civil construction prior to final installation of the equipment. Differential settlement of a few inches across the width of the nuclear island would not have an adverse effect on the safety-related functions of structures, systems, and components.

2.5.4.4 Liquefaction

The Combined License applicant will demonstrate that the potential for liquefaction is negligible.

2.5.4.5 Combined License Information

Combined License applicants referencing the AP1000 design will address the following site specific information related to the geotechnical engineering aspects of the site. No further action is required for sites within the bounds of the site parameters.

2.5.4.5.1 Site and Structures – Site-specific information regarding the underlying site conditions and geologic features will be addressed. This information will include site topographical features, as well as the locations of seismic Category I structures.

2.5.4.5.2 The Combined License applicant will establish the properties of the foundation soils to be within the range considered for design of the nuclear island basemat.

Properties of Underlying Materials – A determination of the static and dynamic engineering properties of foundation soils and rocks in the site area will be addressed. This information will include a discussion of the type, quantity, extent, and purpose of field explorations, as well as logs of borings and test pits. Results of field plate load tests, field permeability tests, and other special field tests (e.g., bore-hole extensometer or pressuremeter tests) will also be provided. Results of geophysical surveys will be presented in tables and profiles. Data will be provided pertaining to site-specific soil layers (including their thicknesses, densities, moduli, and Poisson's ratios) between the basemat and the underlying rock stratum. Plot plans and profiles of site explorations will be provided.

Properties of Materials Adjacent to Nuclear Island Exterior Walls – A determination of the static and dynamic engineering properties of the surrounding soil will be made to demonstrate they are competent and provide passive earth pressures greater than or equal to those used in the seismic stability evaluation for sliding of the nuclear island. Seismic stability requirements are satisfied if the soil layers adjacent to the nuclear island foundation are composed predominantly of rock, or sand and rock (gravel), or sands that can be classified as medium to dense (standard penetration test having greater than 10 blows per foot). If the soil adjacent to the exterior walls is made up of clay, sand and clay, or other types of soil other than those classified above as competent, then the Combined License applicant will evaluate the seismic stability against sliding as described in subsection 3.8.5.5.3 using the site-specific soil properties, or ensure that the soils have properties that exceed the following:

- Submerged soil density of 60 pounds/ft^3
- Angle of internal friction of 32 degrees

Laboratory Investigations of Underlying Materials – Information about the number and type of laboratory tests and the location of samples used to investigate underlying materials will be provided. Discussion of the results of laboratory tests on disturbed and undisturbed soil and rock samples obtained from field investigations will be provided.

2.5.4.5.3 Excavation and Backfill – Information concerning the extent (horizontal and vertical) of seismic Category I excavations, fills, and slopes, if any will be addressed. The sources, quantities, and static and dynamic engineering properties of borrow materials will be described in the site-specific application. The compaction requirements, results of field compaction tests, and fill material

properties (such as moisture content, density, permeability, compressibility, and gradation) will also be provided. Information will be provided concerning the specific soil retention system, for example, the soil nailing system, including the length and size of the soil nails, which is based on actual soil conditions and applied construction surcharge loads. If backfill is to be placed adjacent to the exterior walls of the nuclear island, information will be provided concerning compaction of the backfill and any additional loads on the exterior walls of the nuclear island. Information will also be provided on the waterproofing system along the vertical face and the mudmat. Information will be provided on the mudmat to demonstrate its ability to resist the structural bearing and shear loads described in subsection 2.5.4.2. The maximum bearing pressure is 830 psi. The mudmat may be designed as structural plain concrete in accordance with ACI 318-02 (Reference 1). This requires the specified concrete compressive strength to be no less than 2500 psi. The commentary states this requirement is imposed in the code because “lean concrete mixtures may not produce adequately homogeneous material or well formed surfaces.” If the Combined License applicant proposes to use a concrete with strength less than 2500 psi, the applicant must demonstrate that the mix will result in an acceptable homogeneous material.

2.5.4.5.4 Ground Water Conditions – Groundwater conditions will be described relative to the foundation stability of the safety-related structures at the site. The soil properties of the various layers under possible groundwater conditions during the life of the plant will be compared to the range of values assumed in the standard design in Table 2-1.

2.5.4.5.5 Liquefaction Potential – Soils under and around seismic Category I structures will be evaluated for liquefaction potential for the site specific SSE ground motion. This should include justification of the selection of the soil properties, as well as the magnitude, duration, and number of excitation cycles of the earthquake used in the liquefaction potential evaluation (e.g., laboratory tests, field tests, and published data). Liquefaction potential will also be evaluated to address seismic margin.

2.5.4.5.6 Bearing Capacity – The Combined License applicant will verify that the site-specific allowable soil bearing capacities for static and dynamic loads are equal to or greater than the values documented in Table 2-1, or will provide a site-specific evaluation as described in subsection 2.5.4.2. The acceptance criteria for this evaluation are those of Standard Review Plan 2.5.4 as follows:

- The static and dynamic loads, and the stresses and strains induced in the soil surrounding and underlying the nuclear island, are conservatively and realistically evaluated.
- The consequences of the induced soil stresses and strains, as they influence the soil surrounding and underlying the nuclear island, have been conservatively assessed.

2.5.4.5.7 Earth Pressures – The Combined License applicant will describe the design for static and dynamic lateral earth pressures and hydrostatic groundwater pressures acting on plant safety-related facilities using soil parameters as evaluated in previous subsections.

2.5.4.5.8 Soil Properties for Seismic Analysis of Buried Pipes – The AP1000 does not utilize safety related buried piping. No additional information is required on soil properties.

2.5.4.5.9 Static and Dynamic Stability of Facilities – Soil characteristics affecting the stability of the nuclear island will be addressed including foundation rebound, settlement, and differential settlement.

2.5.4.5.10 Subsurface Instrumentation – Data will be provided on instrumentation, if any, proposed for monitoring the performance of the foundations of the nuclear island. This will specify the type, location, and purpose of each instrument, as well as significant details of installation methods. The location and installation procedures for permanent benchmarks and markers for monitoring the settlement will be addressed.

2.5.5 Combined License Information for Stability of Slopes

Combined License applicants referencing the AP1000 design will address site-specific information about the static and dynamic stability of soil and rock slopes, the failure of which could adversely affect the nuclear island.

2.5.6 Combined License Information for Embankments and Dams

Combined License applicants referencing the AP1000 design will address site-specific information about the static and dynamic stability of embankments and dams, the failure of which could adversely affect the nuclear island.

2.6 References

1. American Concrete Institute (ACI), "Building Code Requirements for Structural Concrete," ACI 318-02.

Table 2-1 (Sheet 1 of 3)

SITE PARAMETERS

Air Temperature	
Maximum Safety [a]	115°F dry bulb/80°F coincident wet bulb 81°F wet bulb (noncoincident)
Minimum Safety [a]	-40°F
Maximum Normal [b]	100°F dry bulb/77°F coincident wet bulb 80°F wet bulb (noncoincident) [d]
Minimum Normal [b]	-10°F
Wind Speed	
Operating Basis	145 mph (3 second gust); importance factor 1.15 (safety), 1.0 (nonsafety); exposure C; topographic factor 1.0
Tornado	300 mph
Seismic	
SSE	0.30g peak ground acceleration [c]
Fault Displacement Potential	None
Soil	
Average Allowable Static Bearing Capacity	Greater than or equal to 8,600 lb/ft^2 over the footprint of the nuclear island at its excavation depth
Maximum Allowable Dynamic Bearing Capacity for Normal Plus SSE	Greater than or equal to 120,000 lb/ft^2 at the edge of the nuclear island at its excavation depth
Shear Wave Velocity	Greater than or equal to 8,000 ft/sec based on low-strain best-estimate soil properties over the footprint of the nuclear island at its excavation depth
Liquefaction Potential	None
Missiles	
Tornado	4000 - lb automobile at 105 mph horizontal, 74 mph vertical 275 - lb, 8 in. shell at 105 mph horizontal, 74 mph vertical 1 inch diameter steel ball at 105 mph horizontal and vertical
Flood Level	Less than plant elevation 100′
Ground Water Level	Less than plant elevation 98′

Table 2-1 (Sheet 2 of 3)

SITE PARAMETERS

Plant Grade Elevation	Less than plant elevation 100′ except for portion at a higher elevation adjacent to the annex building
Precipitation	
Rain	19.4 in./hr (6.3 in./5 min)
Snow/Ice	75 pounds per square foot on ground with exposure factor of 1.0 and importance factors of 1.2 (safety) and 1.0 (non-safety)
Atmospheric Dispersion Values - χ/Q[e]	
Site boundary (0-2 hr)	≤ 5.1 x 10^{-4} sec/m^3
Site boundary (annual average)	≤ 2.0 x 10^{-5} sec/m^3
Low population zone boundary	
0 - 8 hr	≤ 2.2 x 10^{-4} sec/m^3
8 - 24 hr	≤ 1.6 x 10^{-4} sec/m^3
24 - 96 hr	≤ 1.0 x 10^{-4} sec/m^3
96 - 720 hr	≤ 8.0 x 10^{-5} sec/m^3
Population Distribution	
Exclusion area (site)	0.5 mi

Notes:
(a) Maximum and minimum safety values are based on historical data and exclude peaks of less than 2 hours duration.
(b) Maximum and minimum normal values are the 1 percent exceedance magnitudes.
(c) With ground response spectra (at foundation level of nuclear island) as given in Figures 3.7.1-1 and 3.7.1-2.
(d) The noncoincident wet bulb temperature is applicable to the cooling tower only.
(e) For AP1000, the terms “site boundary” and “exclusion area boundary” are used interchangeably. Thus, the χ/Q specified for the site boundary applies whenever a discussion refers to the exclusion area boundary.

Table 2-1 (Sheet 3 of 3)

SITE PARAMETERS

Control Room Atmospheric Dispersion Factors (χ /Q) for Accident Dose Analysis					
χ/Q (s/m³) at HVAC Intake for the Identified Release Points(1)					
	Plant Vent or PCS Air Diffuser(3)	**Ground Level Containment Release Points(4)**	**PORV and Safety Valve Releases(5)**	**Steam Line Break Releases**	**Fuel Handling Area(6)**
0 - 2 hours	2.2E-3	2.2E-3	2.0E-2	2.4E-2	6.0E-3
2 - 8 hours	1.4E-3	1.4E-3	1.8E-2	2.0E-2	4.0E-3
8 - 24 hours	6.0E-4	6.0E-4	7.0E-3	7.5E-3	2.0E-3
1 - 4 days	4.5E-4	4.5E-4	5.0E-3	5.5E-3	1.5E-3
4 - 30 days	3.6E-4	3.6E-4	4.5E-3	5.0E-3	1.0E-3
χ/Q (s/m³) at Control Room Door for the Identified Release Points(2)					
	Plant Vent or PCS Air Diffuser(3)	**Ground Level Containment Release Points(4)**	**PORV and Safety Valve Releases(5)**	**Steam Line Break Releases**	**Fuel Handling Area(6)**
0 - 2 hours	6.6E-4	6.6E-4	4.0E-3	4.0E-3	6.0E-3
2 - 8 hours	4.8E-4	4.8E-4	3.2E-3	3.2E-3	4.0E-3
8 - 24 hours	2.1E-4	2.1E-4	1.2E-3	1.2E-3	2.0E-3
1 - 4 days	1.5E-4	1.5E-4	1.0E-3	1.0E-3	1.5E-3
4 - 30 days	1.3E-4	1.3E-4	8.0E-4	8.0E-4	1.0E-3

Notes:

1. These dispersion factors are to be used 1) for the time period preceding the isolation of the main control room and actuation of the emergency habitability system, 2) for the time after 72 hours when the compressed air supply in the emergency habitability system would be exhausted and outside air would be drawn into the main control room, and 3) for the determination of control room doses when the non-safety ventilation system is assumed to remain operable such that the emergency habitability system is not actuated.
2. These dispersion factors are to be used when the emergency habitability system is in operation and the only path for outside air to enter the main control room is that due to ingress/egress.
3. These dispersion factors are used for analysis of the doses due to a postulated small line break outside of containment. The plant vent and PCS air diffuser are potential release paths for other postulated events (loss-of-coolant accident, rod ejection accident, and fuel handling accident inside the containment); however, the values are bounded by the dispersion factors for ground level releases.

4. The listed values represent modeling the containment shell as a diffuse area source, and are used for evaluating the doses in the main control room for a loss-of-coolant accident, for the containment leakage of activity following a rod ejection accident, and for a fuel handling accident occurring inside the containment.
5. The listed values bound the dispersion factors for releases from the steam line safety & power-operated relief valves and the condenser air removal stack. These dispersion factors would be used for evaluating the doses in the main control room for a steam generator tube rupture, a main steam line break, a locked reactor coolant pump rotor, and for the secondary side release from a rod ejection accident. Additionally, these dispersion coefficients are conservative for the small line break outside containment.
6. The listed values bound the dispersion factors for releases from the fuel storage and handling area. The listed values also bound the dispersion factors for releases from the fuel storage area in the event that spent fuel boiling occurs and the fuel building relief panel opens on high temperature. These dispersion factors are used for the fuel handling accident occurring outside containment and for evaluating the impact of releases associated with spent fuel pool boiling.

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

LIST OF TABLES

LIST OF TABLES (Cont.)

LIST OF TABLES (Cont.)

LIST OF TABLES (Cont.)

LIST OF FIGURES

LIST OF FIGURES (Cont.)

LIST OF FIGURES (Cont.)

LIST OF FIGURES (Cont.)

LIST OF FIGURES (Cont.)

LIST OF FIGURES (Cont.)

CHAPTER 3

DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT AND SYSTEMS

3.1 Conformance with Nuclear Regulatory Commission General Design Criteria

This section discusses the extent to which the AP1000 design criteria for safety-related structures, systems, and components comply with 10 CFR 50, Appendix A. As presented in this section, each criterion is first quoted and then discussed. For some criteria, the AP1000 advanced passive design features are deemed to be significantly different in certain specific areas from those design features considered when the General Design Criteria were formulated. In those instances, the means by which the AP1000 design complies with the intent of the General Design Criterion is indicated. Where additional information is required for a complete discussion, the appropriate Design Control Document (DCD) sections are referenced.

3.1.1 Overall Requirements

Criterion 1 – Quality Standards and Records

Structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy, and sufficiency and shall be supplemented or modified, as necessary, to assure a quality product, in keeping with the required safety function.

A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection, and testing of structures, systems, and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

AP1000 Compliance

The Quality Assurance Program for the AP1000 provides confidence that safety-related items and services are designed, procured, fabricated, inspected, and tested to quality standards commensurate with the safety-related functions to be performed. This program also applies to design services subcontracted to external organizations. The quality assurance program for erection of structures, systems, and components will be identified before the construction phase of the AP1000 project. The AP1000 quality assurance program is described in Chapter 17, including its compliance with ASME NQA-1.

Design, procurement, fabrication, inspection, and testing are performed according to recognized codes, standards, and design criteria that comply with the requirements of 10 CFR 50.55a. As necessary, supplemental standards, design criteria, and requirements are developed by the AP1000 designers. A portion of the chemical and volume control system that is defined as reactor coolant pressure boundary uses an alternate classification in conformance with the requirements of 10 CFR 50.55a(a)(3). The alternate classification is discussed in subsection 5.2.1.3.

Appropriate records documenting that design, procurement, fabrication, inspection, and testing comply with the applicable codes, standards, and design criteria are maintained according to appropriate, applicable laws and regulations, either by or under the control of the Combined License applicant.

In the passive AP1000 design, systems necessary to provide the reactor coolant pressure boundary, the capability to shut down the reactor and maintain it in a safe shutdown condition, and the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guideline exposures of 10 CFR 100 are classified as safety-related. Therefore, the AP1000 complies with the intent of Criterion 1.

The principal design criteria, design bases, codes, and standards applied to the facility are identified in Section 3.2. Additional details may be found in the pertinent sections dealing with safety-related structures, systems, and components.

Criterion 2 – Design Bases for Protection Against Natural Phenomena

Structures, systems, and components important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without the loss of the capability to perform their safety functions. The design bases for these structures, systems, and components shall reflect: (1) appropriate consideration of the most severe of the natural phenomena that have been historically reported for the site and surrounding area, with sufficient margin for the limited accuracy, quantity, and period of time in which the historical data have been accumulated, (2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena, and (3) the importance of the safety functions to be performed.

AP1000 Compliance

The safety-related structures, systems, and components are designed to withstand the effects of natural phenomena without loss of the capability to perform their safety-related functions, or are designed such that their response or failure will be in a safe condition. Those structures, systems, and components vital to the shutdown capability of the reactor are designed to withstand the maximum probable natural phenomena at the intended site.

Accident analyses consider conservative site conditions that envelope expected sites. Appropriate combinations of structural loadings from normal, accident, and natural phenomena are considered in the plant design. The design of the plant in relationship to those natural phenomena is addressed.

Seismic and quality group classifications and other pertinent standards and information are given in the sections discussing individual structures, systems, and components as well as in Chapter 3. The nature and magnitude of the natural phenomena considered in the design of this plant are discussed in Chapter 2.

Criterion 3 – Fire Protection

Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat-resistant materials shall be used wherever practical throughout the unit, particularly in locations such as the containment and control room. Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety. Fire fighting systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components.

AP1000 Compliance

The safety-related structures, systems, and components are designed to minimize the probability and effect of fires and explosions. Noncombustible and fire-resistant materials are used in the containment and main control room. Additionally noncombustible and fire-resistant materials are used on components of safety-related systems, and elsewhere in the plant where fire is a potential risk to safety-related systems.

For example, electrical cables have a fire-retardant jacketing, and fire barriers are used at fire area boundaries. The AP1000 design approach includes designing the safety-related systems with redundant divisions, and locating these redundant divisions in separate safety-related areas.

Equipment and facilities for fire protection, including detecting, alarming, and extinguishing functions, are provided to help protect both plant equipment and personnel from fire, explosion, and the resultant release of toxic vapors. Fire protection is provided by deluge systems (water spray), sprinklers, and portable extinguishers. Fire fighting systems are designed so that their rupture or inadvertent operation will not prevent safety-related systems from performing their design functions.

The following codes, guides, and standards are used as guidelines in the design of the fire protection system and equipment. The system and equipment conform to the applicable portions of the following documents:

- National Fire Protection Association, "National Fire Codes," 1984
- BTP-CMEB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants," July 1981

Subsection 9.5.1 describes the AP1000 fire protection system and equipment, including conformance with the applicable portions of these codes and standards.

Criterion 4 – Environmental and Missile Design Bases

Structures, systems, and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic

effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit.

AP1000 Compliance

Safety-related structures, systems, and components are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss of coolant accidents.

The AP1000 design has emphasized the minimization of missiles, pipe whip, and fluid discharge by a combination of separation of safe shutdown components and design to prevent the dynamic effects of postulated pipe ruptures based on the application of the leak-before-break approach. This analysis is discussed in subsection 3.4.3.5 and Section 3.6.

The AP1000 structures, systems, and components are appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. Details of the design, environmental testing, and construction of these structures, systems, and components are given in the sections that discuss individual structures, systems, and components, as well as in Sections 3.5 and 3.6.

Criterion 5 – Sharing of Structures, Systems, and Components

Structures, systems, and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining unit.

AP1000 Compliance

The AP1000 is a single-unit plant. If more than one unit were built on the same site, none of the safety-related systems would be shared.

3.1.2 Protection by Multiple Fission Product Barriers

Criterion 10 – Reactor Design

The reactor core and associated coolant, control, and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

AP1000 Compliance

The reactor core and associated coolant, control, and protection systems are designed to the following criteria:

- No fuel damage occurs during normal core operation and operational transients (Condition I) or during transient conditions arising from occurrences of moderate frequency (Condition II).

For normal operation, the plant is designed to accommodate a fuel defect level of up to 0.25 percent. Fuel damage, as used here, is defined as penetration of the fission product barrier, that is, the fuel rod cladding. The small number of clad defects that may occur are within the capability of the plant cleanup system and are consistent with the plant design bases. For additional information see Section 11.1.

- The reactor can be returned to a safe shutdown state following a Condition III event, with only a small fraction of the fuel rods damaged, although sufficient fuel damage might occur to preclude the immediate resumption of operation.
- The core remains intact with acceptable heat transfer geometry following transients arising from occurrences of limiting faults (Condition IV).

The reactor protection system is designed to actuate a reactor trip whenever necessary to prevent exceeding the fuel design limits. The core design, together with the process and decay heat removal systems, provide this capability under expected conditions of normal operation, with appropriate margins for uncertainties and anticipated transient situations. This includes the effects of the loss of reactor coolant flow, trip of the turbine generator, loss of normal feedwater, and loss of both normal and preferred power sources.

Chapter 4, Reactor, describes the mechanical components of the reactor and reactor core, including the fuel rods and fuel assemblies, the mechanical design, nuclear design, and the thermal hydraulic design. Chapter 7 provides details of the control and protection systems instrumentation design and logic. This information supports the accident analyses documented in Chapter 15. The acceptable fuel design limits are not exceeded for Condition I and II events. Acceptable core cooling is provided for Condition III and IV events.

Criterion 11 – Reactor Inherent Protection

The reactor core and associated coolant systems shall be designed so that in the power-operating range the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity.

AP1000 Compliance

When the reactor is critical, the negative fuel temperature reactivity effects (Doppler feedback) provides prompt reactivity feedback to compensate for a rapid, uncontrolled reactivity excursion. The negative Doppler coefficient of reactivity is provided by the use of a low-enrichment fuel design. This Doppler feedback is the primary reactivity feedback mechanism to provide the inherent core reactivity protection during rapid core reactivity excursions.

For slower reactivity transients that result in moderator temperature increases, the nonpositive moderator temperature coefficient of reactivity provides compensatory reactivity feedback to help control these slower transients. The overall core design establishes a nonpositive moderator temperature coefficient of reactivity.

Chapter 4 provides information pertaining to the core design.

Criterion 12 – Suppression of Reactor Power Oscillations

The reactor core and associated coolant, control, and protection systems shall be designed to assure that power oscillations which can result in conditions exceeding specified acceptable fuel design limits are not possible or can be reliably and readily detected and suppressed.

AP1000 Compliance

Power oscillations of the fundamental mode are inherently eliminated by negative Doppler and nonpositive moderator temperature coefficients of reactivity.

Oscillations, due to xenon spatial effects, in the radial and azimuthal overtone modes are heavily damped because of the inherent design and due to the negative Doppler and nonpositive moderator temperature coefficients of reactivity.

Oscillations due to xenon spatial effects may occur in the axial first overtone mode. Reactor trip functions are provided, using the measured axial power imbalance as an input, so that the fuel design limits are not exceeded during axial xenon oscillations.

If it is necessary to maintain axial imbalance within the limits (that is, imbalances that are alarmed to the operator and are within the imbalance trip setpoints), the operator can suppress axial xenon oscillations by control rod motions or temporary power reductions or both.

Oscillations due to spatial xenon effects, in axial modes higher than the first overtone, are heavily damped because of the inherent design and the negative Doppler coefficient of reactivity.

The stability of the core against xenon-induced power oscillations and the functional requirements of instrumentation for monitoring and measuring core power distribution are discussed in Chapter 4. Details of the instrumentation design and logic are discussed in Chapter 7.

Criterion 13 – Instrumentation and Control

Instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

AP1000 Compliance

Instrumentation and controls are provided to monitor and control neutron flux, control rod position, fluid temperatures, pressures, flows, and levels, as necessary, to maintain plant safety. Instrumentation is provided in the reactor coolant system, steam and power conversion system, containment, engineered safety systems, radioactive waste management systems, and other auxiliary systems.

See Section 7.5 for a discussion of indications that are required for operator use under normal operating and accident conditions. Criteria regarding layout of the controls and displays are provided in Chapter 18.

The quantity and types of process instrumentation used provide safe and orderly operation of systems over the design range of plant operations, including accident conditions.

Criterion 14 – Reactor Coolant Pressure Boundary

The reactor coolant pressure boundary shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

AP1000 Compliance

The reactor coolant pressure boundary is designed to accommodate the system pressures and temperatures attained under the expected modes of plant operation, including anticipated transients, while maintaining stresses within applicable limits. Consideration is given to loadings under normal operating conditions and to abnormal loadings, such as seismic loadings. The piping is protected from overpressure by means of pressure-relieving devices, as required by ASME Code, Section III. See subsection 5.2.2 for additional information.

Reactor coolant pressure boundary materials and fabrication techniques are such that there is a low probability of gross rupture or significant leakage. The AP1000 reactor coolant system design incorporates revised pipe-break criteria (leak-before-break) to reduce or eliminate the need to consider the dynamic effects of pipe breaks. The configuration and materials of the reactor coolant system have been selected such that the pipe stresses meet the leak-before-break criteria. See subsection 3.9.3 for additional information.

The AP1000 reactor core and reactor internals are designed to limit neutron fluence on the reactor vessel. See Section 5.4 and Chapter 4 for additional information.

The reactor vessel is manufactured from low-alloy carbon steel clad with 308L stainless steel weld overlay on wetted surfaces. The vessel shell is constructed of ring-rolled forgings that eliminate vertical weld seams. Chemical composition of the forging material is controlled to improve radiation resistance of the vessel. (See Criterion 31 for further discussion of the reactor coolant pressure boundary.)

Coolant chemistry is controlled to protect the materials of construction of the reactor coolant pressure boundary from corrosion. See subsection 5.2.3 for additional information.

The reactor coolant pressure boundary welds are accessible for in-service inspections to assess structural and leaktight integrity. For the reactor vessel, a material surveillance program is provided. Instrumentation is provided to detect significant leakage from the reactor coolant pressure boundary, with indication in the main control room. See subsection 5.2.4 for additional information.

A portion of the chemical and volume control system that is defined as reactor coolant pressure boundary is nonsafety related. This portion of the system is capable of being automatically isolated by safety-related valves that are designed and qualified for the design requirements.

Criterion 15 – Reactor Coolant System Design

The reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during normal operation, including anticipated operational occurrences.

AP1000 Compliance

Steady-state and transient analyses are performed to demonstrate that reactor coolant system design conditions are not exceeded during normal operation. Protection and control setpoints are based on these analyses. See Chapter 15 for additional information.

The reactor coolant system stress analysis and the leak-before-break analyses are described in Appendices 3B and 3C. See Section 5.3 for additional information.

Two safety valves are provided for the reactor coolant system. These valves and their setpoints meet the ASME Code, Section III criteria for overpressure protection. See subsection 5.2.2 for additional information.

Criterion 16 – Containment Design

The reactor containment and associated systems shall be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment and to assure that the containment design conditions important to safety are not exceeded for as long as postulated accident conditions require.

AP1000 Compliance

The containment is an integral part of the overall containment system, whose function is to contain the release of airborne radioactivity following postulated design basis accidents and to provide shielding for the reactor core and the reactor coolant system during normal operations. The containment consists of a steel containment vessel and is surrounded by a concrete shield building.

The containment vessel, which is a free-standing steel shell, is an integral part of the passive containment cooling system, whose function is to provide the safety-related ultimate heat sink for the removal of the reactor coolant system sensible heat, core decay heat, and stored energy. The containment vessel and the passive containment cooling system are designed to remove sufficient energy from the containment to prevent the containment from exceeding its design pressure following postulated design basis accidents.

The containment is designed to house the reactor coolant system and other related systems. The containment vessel functions as an essentially leaktight barrier. It is protected against postulated missiles from external sources as well as missiles produced by internal equipment failures.

Containment penetrations are isolated according to the provisions of GDCs 54, 55, 56, and 57.

Criterion 17 – Electrical Power Systems

An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming that the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electric power supplies, including the batteries, and the onsite electric distribution system shall have sufficient independence, redundancy, and testability to perform their safety functions, assuming a single failure.

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights-of-way) designed and located so as to minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time, following a loss of all onsite alternating current power supplies and other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss of coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

AP1000 Compliance

The AP1000 plant design supports an exemption to the requirement of GDC 17 for two physically independent offsite circuits by providing safety-related passive systems for core cooling and containment integrity, and multiple nonsafety-related onsite and offsite electric power sources for other functions. See Section 6.3 for additional information on the systems for core cooling.

A reliable dc power source supplied by batteries provides power for the safety-related valves and instrumentation during transient and accident conditions.

The Class 1E dc and UPS system is the only safety-related power source required to monitor and actuate the safety-related passive systems. Otherwise, the plant is designed to maintain core cooling and containment integrity, independent of nonsafety-related ac power sources indefinitely. The only electric power source necessary to accomplish these safety-related functions is the Class 1E dc and UPS power system which includes the associated safety-related 120V ac distribution switchgear.

Although the AP1000 is designed with reliable nonsafety-related offsite and onsite ac power that are normally expected to be available for important plant functions, nonsafety-related ac power is not relied upon to maintain the core cooling or containment integrity.

The nonsafety-related ac power system is designed such that plant auxiliaries can be powered from the grid under all modes of operation. During loss of offsite power, the ac power is supplied by the onsite standby diesel-generators. Preassigned loads and equipment are automatically loaded on the diesel-generators in a predetermined sequence. Additional loads can be manually added as required. The onsite standby power system is not required for safe shutdown of the plant.

Criterion 18 – Inspection and Testing of Electric Power Systems

Electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features, such as wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the condition of their components. The systems shall be designed with a capability to test periodically (1) the operability and functional performance of the components of the systems, such as onsite power sources, relays, switches, and buses, and (2) the operability of the systems as a whole and, under conditions as close to design as practical, the full operation sequence that brings the systems into operation, including operation of applicable portions of the protection system, and the transfer of power among the nuclear power unit, the offsite power system, and the onsite power system.

AP1000 Compliance

The AP1000 is designed so that only the Class 1E dc and UPS system is required in order to initiate and actuate the systems necessary for maintaining core cooling and containment integrity. The safety-related dc power system design complies with GDC 18. Compliance with GDC 18 is achieved by designing testability and inspection capability into the system. The associated testing requirements are contained in Chapter 16.

Criterion 19 – Control Room

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including loss of coolant accidents. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident.

Equipment at appropriate locations outside the control room shall be provided (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

AP1000 Compliance

The AP1000 main control room provides the man-machine interfaces required to operate the plant safely and efficiently under normal conditions and to maintain it in a safe manner under accident

conditions, including LOCAs. Simplified passive safety-related system designs are provided that do not rely upon operator action to maintain core cooling for design basis accidents. Operator action outside the main control room to mitigate the consequences of an accident is permitted.

The main control room is shielded by the containment and auxiliary building from direct gamma radiation and inhalation doses resulting from the postulated release of fission products inside containment. Refer to Chapter 15 for additional information on accident conditions. The main control room/technical support center HVAC subsystem of the nuclear island nonradioactive ventilation system (VBS) allows access to and occupancy of the main control room under accident conditions as described in subsection 9.4.1. Sufficient shielding and the main control room/technical support center HVAC subsystem provide adequate protection so that personnel will not receive radiation exposure in excess of 5 rem whole-body or its equivalent to any part of the body for the duration of the accident.

If ac power is unavailable for more than 10 minutes or if "high-high" particulate or iodine radioactivity is detected in the main control room supply air duct, which would lead to exceeding General Design Criteria 19 operator dose limits, the protection and safety monitoring system automatically isolates the main control room and operator habitability requirements are then met by the main control room emergency habitability system (VES). The main control room emergency habitability system also allows access to and occupancy of the main control room under accident conditions. The emergency main control room habitability system is designed to satisfy seismic Category I requirements as described in Section 3.2; the system design is described in Section 6.4.

In the event that the operators are forced to abandon the main control room, a workstation is provided with remote shutdown capability. A main control room evacuation is not assumed to occur simultaneously with design basis events. The remote shutdown workstation is described in Section 7.4.

3.1.3 Protection and Reactivity Control Systems

Criterion 20 – Protection System Functions

The protection system shall be designed (1) to initiate automatically the operation of appropriate systems, including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

AP1000 Compliance

The protection system is a microprocessor-based system that trips the reactor and actuates engineered safety features when predetermined limits are exceeded or when manually initiated.

The reactor trip portion of the protection system includes four independent, redundant, physically separated, electrically-isolated divisions. The coincidence circuits guard against the loss of protection or the generation of false protection signals due to equipment failures through the use of a two-out-of-four logic and built-in operational bypasses.

Independent, redundant, physically separated, electrically-isolated engineered safety features trains are provided. Signal conditioning for the plant sensors is provided. Control and status signals are transmitted between the protection system and the main control room and the remote shutdown workstation by electrical data links and between the distributed logic circuits by internally redundant fiber optic data highways.

See Chapter 7 for additional information concerning the design of the protection system.

Criterion 21 – Protection System Reliability and Testability

The protection system shall be designed for high functional reliability and in-service testability commensurate with the safety functions to be performed. Redundancy and independence designed into the protection system shall be sufficient to assure that (l) no single failure results in the loss of the protection function and (2) removal from service of any component or channel does not result in the loss of the required minimum redundancy unless the acceptable reliability of operation of the protection system can be otherwise demonstrated. The protection system shall be designed to permit periodic testing of its functioning when the reactor is in operation, including a capability to test channels independently to determine failures and losses of redundancy that may have occurred.

AP1000 Compliance

The protection system is designed for functional reliability and in-service testability. The design employs redundant logic trains and measurement and equipment diversity.

The protection system equipment includes integral testing circuits. System equipment, from input to output, in the protection cabinets and the engineered safety features cabinets, is tested. Simulated inputs replace the field signals. Outputs are monitored for validity. Manual and automatic testing is used to test the final stages of the reactor trip circuits and the reactor trip switchgear. Testing of cabinets and communications links verifies the functional operation of the equipment and the hardware. See Chapter 7 for further information concerning the test capabilities of the protection system.

Criterion 22 – Protection System Independence

The protection system shall be designed to assure that the effects of natural phenomena, and of normal operating, maintenance, testing, and postulated accident conditions on redundant channels do not result in the loss of the protection function or shall be demonstrated to be acceptable on some other defined basis. Design techniques, such as functional diversity or diversity in component design and principles of operation, shall be used to the extent practical to prevent loss of the protection function.

AP1000 Compliance

Design of the protection systems includes consideration of natural phenomena, normal maintenance, testing, and accident conditions so that the protection functions are available.

Protection system components are designed, arranged, and qualified for operation in the environment accompanying any emergency situation in which the components are required to function.

Functional diversity has been designed into the system. The extent of this functional diversity is demonstrated for a variety of postulated accidents. Diverse protection functions automatically serve to mitigate the consequences of an event. Chapter 15 identifies the primary and diverse protective functions for each of the analyzed events.

Sufficient redundancy and independence are designed into the protection systems so that no single failure or removal from service of any component or channel of a system results in loss of the protection function. Functional diversity and location diversity are designed into the system.

Automatic reactor trip is initiated by neutron flux measurements, reactor coolant system overtemperature delta-T, reactor coolant system overpower delta-T, pressurizer pressure and level measurements, reactor coolant flow, reactor coolant pump speed, reactor coolant pump bearing water temperature, and steam generator water level measurements. Trips may also be initiated manually or by a safety injection signal.

For additional information pertaining to the reactor trip logic, see Section 7.2.

High-quality components, conservative design and quality control, inspection, calibration, and tests are used to guard against common-mode failure. Qualification testing and analysis are performed on the safety-related systems to demonstrate functional operation at normal and post-accident conditions of temperature, humidity, pressure, and radiation for specified periods, as required. Typical protection system equipment is subjected to type tests under simulated seismic conditions, using conservatively large accelerations and applicable frequencies.

See Section 7.1 for additional information concerning the equipment design of the protection and safety monitoring system.

See Sections 3.10 and 3.11 for information pertaining to environmental and seismic qualification of the protection system equipment.

The AP1000 includes a nonsafety-related diverse actuation system. The diverse actuation system provides specific automatic functions including control rod insertion, turbine trip, passive residual heat removal heat exchanger actuation, core makeup tank actuation, isolation of critical containment lines, and passive containment cooling system actuation. This system is diverse and independent from the reactor protection system from sensors up to the actuation devices.

See Section 7.7 for additional information concerning the diverse actuation system.

Criterion 23 – Protection System Failure Modes

The protection system shall be designed to fail into a safe state or into a state demonstrated to be acceptable on some other defined basis if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air) or postulated adverse environments (e.g., extreme heat or cold, fire, pressure, steam, water, and radiation) are experienced.

AP1000 Compliance

The protection system is designed considering the most probable failure modes of the components under various perturbations of the environment and energy sources. Reactor trip channels are designed on the deenergize-to-trip principle so that a single event (that is, loss of power) that could affect many functions at the same time causes the channels to actuate to their tripped conditions.

Criterion 24 – Separation of Protection and Control Systems

The protection system shall be separated from the control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single protection system component or channel which is common to the control and protection systems, leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system. Interconnection of the protection and control systems shall be limited so as to assure that safety is not significantly impaired.

AP1000 Compliance

The protection system is separate and distinct from the control systems. Control systems are, in some cases, dependent on the protection system for control signals that are derived from protection system measurements, where applicable. These signals are transferred to the control system by isolation devices classified as protection components.

The adequacy of the system isolation is verified by testing under conditions of postulated credible faults. The failure of a single control system component or channel, or the failure or removal from service of a single protection system component or channel common to the control and protection system, leaves intact a system that satisfies the requirements of the protection system. The removal of a protection division from service is allowed during testing of the division.

Criterion 25 – Protection System Requirements for Reactivity Control Malfunctions

The protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of the control rods.

AP1000 Compliance

The protection system is designed to limit reactivity transients so that the fuel design limits are not exceeded. Reactor shutdown by control rod insertion is independent of the normal control functions since the trip breakers interrupt power to the rod mechanisms regardless of existing control signals. Thus, in the postulated accidental withdrawal of a control rod or control rod bank (assumed to be initiated by a control malfunction), neutron flux, temperature, pressure, level, and flow signals would be generated independently. Any of these signals (trip demands) would operate the breakers to trip the reactor.

The AP1000 is designed to automatically terminate a boron dilution during manual or automatic operation at power, and also during startup and shutdown conditions. See Chapter 7 for a

discussion of the signals used in the logic to terminate a boron dilution. Subsection 9.3.6.4.5 discusses the chemical and volume control system design features for addressing boron dilution. The Chapter 15 safety analyses demonstrate that fuel design limits are not exceeded.

Criterion 26 – Reactivity Control System Redundancy and Capability

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure that the acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

AP1000 Compliance

Two reactivity control systems are provided. These are rod cluster control assemblies and gray rod assemblies, and chemical shim (boric acid). The rod cluster control and gray rod assemblies are inserted into the core by the force of gravity.

During operation, the shutdown rod banks are fully withdrawn. The control rod system automatically maintains a programmed average reactor temperature compensating for reactivity effects associated with scheduled and transient load changes. See Section 4.3 for additional information.

The shutdown and control rod banks are designed to provide reactivity margin to shut down the reactor during normal operating conditions and during anticipated operational occurrences, without exceeding specified fuel design limits. The safety analyses assume the most restrictive time in the core operating cycle and that the most reactive control rod cluster assembly is in the fully withdrawn position. See Chapter 15 for summaries of the analyses, assumptions, and results.

The safety-related passive systems provide the required boration to establish and maintain safe shutdown condition for the reactor core. See Section 6.3 for additional information.

Criterion 27 – Combined Reactivity Control Systems Capability

The reactivity control systems shall be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity changes to assure that under postulated accident conditions and with appropriate margin for stuck rods the capability to cool the core is maintained.

AP1000 Compliance

The plant is provided with the means of making and holding the core subcritical under any anticipated conditions and with appropriate margin for contingencies. Combined use of the control rod and gray rod assemblies and the chemical shim control system permits the necessary shutdown

margin to be maintained during long-term xenon decay and plant cooldown. The single highest worth control rod assembly is assumed to be stuck in the fully withdrawn position for this determination.

Criterion 28 – Reactivity Limits

The reactivity control systems shall be designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither (l) result in damage to the reactor coolant pressure boundary greater than limited local yielding nor (2) sufficiently disturb the core, its support structures, or other reactor pressure vessel internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

AP1000 Compliance

The maximum reactivity worth of the control rods and the maximum rates of reactivity increase employing control rods and boron removal are limited by design and operating procedures.

The appropriate reactivity addition rate for the withdrawal of control rods and the dilution rate of the boric acid in the reactor coolant system are specified in the precautions, limitations, and setpoint document and the control system setpoint study. Technical specifications explicitly specify control rod bank alignment and insertion limits in addition to shutdown margin reactivity requirements.

The control rod reactivity addition rate is determined by the allowable rod control system withdrawal speed, in conjunction with the control rod worth, which varies throughout the operating cycle. The capability to change boron concentration is determined by the various plant systems that provide makeup to the reactor coolant system. The reactivity insertion rates, rod withdrawal limits, and boron dilution limits are discussed in Chapter 4.

Core cooling capability following events such as rod ejection and steam line breaks is provided by keeping the reactor coolant pressure boundary stresses within faulted condition limits, as specified by applicable ASME codes. Structural deformations are also checked and limited to values that do not jeopardize the operation of needed safety-related features.

Criterion 29 – Protection Against Anticipated Operational Occurrences

The protection and reactivity control systems shall be designed to assure an extremely high probability of accomplishing their safety functions in the event of anticipated operational occurrences.

AP1000 Compliance

The protection and reactivity control systems have an extremely high probability of performing their required safety-related functions in the event of anticipated operational occurrences. High-quality equipment, diversity, and redundancy, support this probability. Loss of power to the

protection system results in a reactor trip. Defense in depth is designed into AP1000 to reduce challenges to the protection and reactivity control systems.

3.1.4 Fluid Systems

Criterion 30 – Quality of Reactor Coolant Pressure Boundary

Components which are part of the reactor coolant pressure boundary shall be designed, fabricated, erected, and tested to the highest quality standards practical. Means shall be provided for detecting and, to the extent practical, identifying the location of the source of reactor coolant leakage.

AP1000 Compliance

Reactor coolant pressure boundary components are designed, fabricated, inspected, and tested in conformance with the ASME Code, Section III. A portion of the chemical and volume control system that is defined as reactor coolant pressure boundary uses an alternate classification in conformance with the requirements of 10 CFR 50.55a(a)(3). The alternate classification is discussed in Section 5.2.

Leakage detection monitoring is accomplished using instrumentation and other components of several systems. See subsection 5.2.5 for additional information. Reactor coolant pressure boundary leakage is classified as either identified or unidentified leakage.

Auxiliary systems connected to the reactor coolant pressure boundary incorporate design and administrative provisions that limit leakage. Leakage is detected by increasing auxiliary system level, temperature, flow, or pressure, by lifting of relief valves, or by increasing values of monitored radiation in the auxiliary system.

Leakage from the reactor coolant pressure boundary and other components not otherwise identified inside the containment will condense and flow by gravity via the floor drains and other drains to the containment sump. Leakage is indicated by an increase in the sump level.

Reactor coolant system inventory monitoring provides an indication of system leakage. The reactor coolant system inventory balance is a quantitative inventory or mass balance calculation.

Leakage from the reactor coolant pressure boundary will result in an increase in the radioactivity levels inside containment. The containment atmosphere is monitored for airborne gaseous radioactivity and N_{13}/F_{18}. From the concentration of N_{13}/F_{18} and the power level, reactor coolant pressure boundary leakage can be estimated.

Criterion 31 – Fracture Prevention of Reactor Coolant Pressure Boundary

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (l) the boundary behaves in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions

and the uncertainties in determining (l) material properties, (2) the effects of irradiation on material properties, (3) residual, steady state, and transient stresses, and (4) size of flaws.

AP1000 Compliance

Control is maintained over material selection and fabrication for the reactor coolant pressure boundary components so that the boundary behaves in a nonbrittle manner. The portion of the chemical and volume control system that uses an alternate classification is not required to meet the requirements to prevent brittle failure. The reactor coolant pressure boundary materials exposed to the coolant are corrosion-resistant stainless steel or nickel-chromium-iron alloy. The nil-ductility transition reference temperature of the reactor vessel structural steel is established by Charpy V-notch and drop weight tests in accordance with 10 CFR 50, Appendix G (Reference 1). See Section 5.3 for additional information.

The following requirements are imposed in addition to those specified by the ASME Code, Section III.

- A 100 percent volumetric ultrasonic shear wave test of reactor vessel plate and a post-hydrotest ultrasonic map of welds in the pressure vessel are required. Cladding bond ultrasonic inspection to more restrictive requirements than those specified in the ASME Code, Section III is also required in order to preclude interpretation problems during in-service inspection.

- In the surveillance programs, 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 l/2T compact tension specimens. These programs are directed toward evaluation of the effect of radiation on the fracture toughness of reactor vessel steels based on the reference transition temperature approach and the fracture mechanics approach, and are in accordance with ASTM, E-185 (Reference 2).

- Reactor vessel core region material chemistry (copper, phosphorous, and vanadium) is controlled to reduce sensitivity to embrittlement due to irradiation over the life of the plant.

The fabrication and quality control techniques used in the fabrication of the reactor coolant system are governed by ASME Code, Section III requirements.

Allowable pressure-temperature relationships for plant heatup and cooldown rates are calculated using methods derived from the ASME Code, Section III, Appendix G. The approach specifies that the allowable stress intensity factors for vessel-operating conditions do not exceed the reference stress intensity factor for the metal temperature. Operating specifications include conservative margins for predicted changes in the material reference temperatures due to irradiation.

Criterion 32 – Inspection of Reactor Coolant Pressure Boundary

Components which are part of the reactor coolant pressure boundary shall be designed to permit (l) periodic inspection and testing of important areas and features to assess their structural and leak-tight integrity and (2) an appropriate material surveillance program for the reactor pressure vessel.

AP1000 Compliance

The design of the reactor coolant pressure boundary provides accessibility to the internal surfaces of the reactor vessel and most external zones of the vessel, including the nozzle-to-reactor coolant piping welds, the top and bottom heads, and external surfaces of the reactor coolant piping, except for the area of pipe within the primary shield concrete. The inspection capability complements the leakage detection systems in assessing the integrity of the pressure boundary components. The reactor coolant pressure boundary will be periodically inspected under the provisions of the ASME Code, Section XI. Section 5.1 provides the reactor coolant system primary loop drawings. The portion of the chemical and volume control system that uses an alternate classification is constructed to requirements that do not require inservice inspection.

Monitoring of changes in the fracture toughness properties of the reactor vessel core region plates, forgings, weldments, and associated heat-treated zones is performed according to 10 CFR 50, Appendix H. Additionally, samples of reactor vessel plate materials are retained and catalogued in case future engineering development shows the need for further testing.

The material properties surveillance program includes conventional tensile and impact tests and fracture mechanics specimens. The observed shifts in the nil-ductility transition reference temperature of the core region materials with irradiation is used to confirm the allowable limits calculated for operational transients.

The design of the reactor coolant pressure boundary piping provides for accessibility of welds requiring in-service inspection under the provisions of the ASME Code, Section XI. Removable insulation is provided at welds requiring in-service inspection. See Section 5.3 and subsection 5.2.4 for additional information.

Criterion 33 – Reactor Coolant Makeup

A system to supply reactor coolant makeup for protection against small breaks in the reactor coolant pressure boundary shall be provided. The system safety function shall be to assure that specified acceptable fuel design limits are not exceeded as a result of reactor coolant loss due to leakage from the reactor coolant pressure boundary and rupture of small piping or other small components which are part of the boundary. The system shall be designed to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished using the piping, pumps, and valves used to maintain coolant inventory during normal reactor operation.

AP1000 Compliance

Changes in the reactor coolant volume will be accommodated by the pressurizer level program for normal power changes, including the transition from hot standby to full-power operation and returning to hot standby. In addition, the pressurizer has sufficient volume to accommodate minor reactor coolant system leakage.

Safety-related passive reactor coolant system makeup is provided to accommodate small leaks when the normal makeup system is unavailable and to accommodate larger leaks resulting from loss of coolant accidents. Safety-related reactor coolant makeup and safety injection are provided by two core makeup tanks, two accumulators, and an in-containment refueling water storage tank. Long-term cooling is provided by containment gravity recirculation of reactor coolant within containment. See Section 6.3 for additional information. The safety-related reactor coolant makeup relies on the Class 1E and UPS system. Neither onsite or offsite ac power is required.

In addition, the nonsafety-related chemical and volume control system automatically provides inventory control to accommodate minor leakage from the reactor coolant system, expansion during heatup from cold shutdown, and contraction during cooldown. This inventory control is provided by letdown and makeup connections to the chemical and volume control system purification loop. Redundant pumps with connections to redundant nonsafety-related onsite ac power are provided when offsite power is not available and these pumps can be supplied from offsite power when onsite power is not available. See Section 5.2 for additional information.

Criterion 34 – Residual Heat Removal

A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

"Suitable redundancy in components and features and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

AP1000 Compliance

The AP1000 design satisfies the intent of GDC 34 by reducing the risk associated with loss of the decay heat removal function through a combination of safety-related passive systems, together with nonsafety-related active systems. Specific decay heat removal systems include the following:

- A safety-related passive residual heat removal heat exchanger that uses natural circulation flow and that does not require electrical power for operation

- Automatic, safety-related feed and bleed using the core makeup tanks, accumulators, and the in-containment refueling water storage tank for injection and the automatic depressurization system valves for reactor coolant system venting

- The nonsafety-related main feedwater system with motor-driven pumps supplied by the main generator or by offsite power
- The nonsafety-related startup feedwater system with motor-driven pumps supplied by offsite or onsite power, including automatic sequencing on the nonsafety-related diesel generators
- The nonsafety-related normal residual heat removal system with motor-driven pumps supplied by offsite or onsite power, including nonsafety-related diesel generators, for use at low reactor coolant system pressures

A safety-related emergency feedwater system is not required for the AP1000 design. An active safety-related residual heat removal system is not required for the AP1000.

The AP1000 passive core cooling system, in conjunction with the passive containment cooling system, provides a reliable capability for removing decay heat from the reactor core and maintains sufficient water inventory to provide adequate core cooling for an extended period of time. The system does not depend upon pumped injection or recirculation, and actuates automatically, requiring no operator actions.

The containment arrangement addresses the Regulatory Guide 1.82 issues. Functional performance of the system addresses the guidelines of Regulatory Guide 1.139, except that cooldown rate is somewhat more limited when using the passive residual heat removal equipment. See subsection 1.9.1 for additional information.

The passive core cooling system provides both gravity injection and gravity recirculation, automatically shifting injection modes when the proper containment flood-up conditions are achieved.

The AP1000 design provides a passive decay heat removal system that functions independent of nonsafety-related ac power supplies and can accommodate single active failures. (The Class 1E dc and UPS system supplies power to the safety-related monitoring and control instrumentation.) The passive core cooling system complies with General Design Criterion 34 by providing the capability to remove decay heat without relying on nonsafety-related ac power.

Criterion 35 – Emergency Core Cooling

A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that (l) fuel and clad damage that could interfere with continued effective core cooling is prevented and (2) clad metal-water reaction is limited to negligible amounts.

Suitable redundancy in components and features and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

AP1000 Compliance

The AP1000 design provides for safety-related passive reactor coolant makeup. Core makeup tanks accommodate small leaks when the normal makeup system is unavailable and provide safety injection for small-break loss of coolant accidents. Accumulators provide the high makeup flow required for a large loss of coolant accident and initiate injection when the reactor coolant system pressure is below the static accumulator pressure during a small-break loss of coolant accident.

The in-containment refueling water storage tank, and after containment flood-up, containment recirculation capability provide the long-term source of gravity injection to the core after the reactor coolant system is depressurized. The automatic depressurization system valves provide the vent path to transfer the core decay heat to the containment and then to the ultimate heat sink.

The AP1000 design provides a passive core cooling system that functions independent of ac power supplies, assuming single active failures. The passive core cooling system does not need the nonsafety-related diesel-generators for electrical power to either actuate or operate the various system components. Therefore, the passive core cooling system complies with the intent of GDC 35 by providing the capability for core cooling without relying on nonsafety-related ac power sources.

Criterion 36 – Inspection of Emergency Core Cooling System

The emergency core cooling system shall be designed to permit appropriate periodic inspection of important components, such as spray rings in the reactor pressure vessel, water injection nozzles, and piping, to assure the integrity and capability of the system.

AP1000 Compliance

The AP1000 design includes a passive core cooling system that provides emergency core decay heat removal, emergency reactor coolant system makeup and boration, safety injection, and containment sump pH control. The system piping and components are designed to permit access for periodic inspection and testing of equipment, according to the ASME Code and technical specification requirements, to provide confidence in the integrity and capability of the system.

The core makeup tanks, accumulators, and passive residual heat removal heat exchanger have manways which permit access for inspection and required maintenance. The in-containment refueling water storage tank design provides access for both the tank itself and for the passive residual heat removal heat exchanger, spargers, and other components located inside the tank.

In addition, the system piping provides accessibility for inspection and maintenance to the extent practical. See Section 6.3 for additional information.

Criterion 37 – Testing of Emergency Core Cooling System

The emergency core cooling system shall be designed to permit appropriate periodic pressure and functional testing to assure (l) the structural and leak-tight integrity of its components, (2) the operability and performance of the active components of the system, and (3) the operability of the system as a whole and under conditions as close to design as practical, the performance of the full

operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

AP1000 Compliance

The AP1000 passive core cooling system is designed to permit the periodic inspection and testing of the appropriate system components. The testing capabilities of the system including in-service testing and inspection to confirm the structural and leaktight integrity of various components, technical specification operability and performance of the active system components, and additional in-service testing to confirm the overall operability of the system.

The stage 1, 2, and 3 automatic depressurization system valves have provisions for shutdown in-service testing and at-power operability testing.

Planned shutdown testing includes operability testing of the component and system performance, including operation of applicable portions of the protection and safety monitoring system and the use of the appropriate power sources for the system.

The AP1000 design has significantly reduced the support systems required for system operation. In-service testing of the required support systems is also planned.

Criterion 38 – Containment Heat Removal System

A system to remove heat from the reactor containment shall be provided. The system safety function shall be to reduce rapidly, consistent with the functioning of other associated systems, the containment pressure and temperature following any loss of coolant accident and maintain them at acceptably low levels.

Suitable redundancy in components and features and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

AP1000 Compliance

The AP1000 design uses passive systems for post-loss of coolant accident core and containment heat removal and for the prevention of overpressurization failure of the containment building. Heat is transferred from the containment atmosphere to the steel containment shell by natural convection and condensation. Heat removal from the exterior of the containment shell is enhanced by a directed-flow natural convection design and a passive, external cooling water distribution system.

The AP1000 passive containment cooling system is designed with sufficient capacity to prevent the containment from exceeding its design pressure with no operator action or outside assistance for a minimum of 3 days. After 3 days, limited operator action is required.

The AP1000 passive containment cooling system consists of a steel containment shell and associated water supplies, piping, valves, and air baffle. The passive containment cooling system is a passive system that uses gravity and natural circulation as driving forces. The design of the AP1000 passive containment cooling system does not require the use of any pumps, and it functions independent of nonsafety-related ac power sources for 3 days. Therefore, the passive containment cooling system can function during loss of offsite or onsite power. GDC 38 is satisfied by using appropriate redundancy and by the design of the passive containment cooling system and its reliance on natural forces.

Criterion 39 – Inspection of Containment Heat Removal System

The containment heat removal system shall be designed to permit appropriate periodic inspection of important components, such as the torus, sumps, spray nozzles and piping, to assure the integrity and capability of the system.

AP1000 Compliance

The AP1000 design uses safety-related passive means for containment heat removal. The design of the system allows for inspection of piping, valves, the containment shell and air baffle, and other components to provide confidence in the integrity and capability of the system.

The periodic inspections specified in the ASME Code and technical specifications provide confidence that the capability of these heat removal systems is retained through plant life.

Criterion 40 – Testing of Containment Heat Removal System

The containment heat removal system shall be designed to permit appropriate periodic pressure and functional testing to assure (l) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the system, and (3) the operability of the system as a whole, and, under conditions as close to the design as practical the performance of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

AP1000 Compliance

The AP1000 design includes a passive containment cooling system that provides containment heat removal to limit the peak containment pressure following design basis events. The system piping and components are designed to permit access for periodic inspection and testing of equipment, according to the ASME Code and technical specification requirements, to provide confidence in the integrity and capability of the system.

The passive containment cooling water storage tank design allows access for both the tank and for the various components located inside the tank.

In addition, the system piping provides accessibility for inspection and maintenance to the extent practical. See Section 6.2 for additional information.

Criterion 41 – Containment Atmosphere Cleanup

Systems to control fission products, hydrogen, oxygen, and other substances which may be released into the reactor containment shall be provided, as necessary, to reduce, consistent with the functioning of other associated systems, the concentration and quantity of fission products released to the environment following postulated accidents and to control the concentration of hydrogen or oxygen and other substances in the containment atmosphere following postulated accidents to assure that containment integrity is maintained.

Each system shall have suitable redundancy in components and features and suitable interconnections, leak detection, isolation, and containment capabilities to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) its safety function can be accomplished, assuming a single failure.

AP1000 Compliance

Fission product control for the AP1000 plant is provided via natural removal processes within containment and by limiting containment leakage. The passive removal processes such as deposition and sedimentation are evaluated based on a physically-based source term with large scale core damage. See Section 6.5 for additional details. The containment and penetration design includes features specifically designed to minimize overall containment leakage. See subsection 6.2.3 for additional details.

The generation of hydrogen in the containment under post-accident conditions has been evaluated, and the containment hydrogen control system has been designed such that the following criteria are satisfied:

- In compliance with Section 50.44 of 10 CFR 50, means are provided to measure and control post-loss of coolant accident hydrogen concentrations.

- The combustible concentrations of hydrogen do not accumulate in the areas where unintended combustion or detonation could cause loss of containment integrity or loss of appropriate mitigating features.

- Internal passive autocatalytic recombiners are provided for hydrogen control following a design basis loss of coolant accident.

- Hydrogen igniters are provided to limit local and global hydrogen concentrations to below 10 percent following a degraded core event with the reaction of 100 percent of the zircaloy cladding.

- The concentration of uniformly distributed hydrogen produced by the equivalent of a 75 percent active fuel-clad metal water reaction does not exceed 13 percent by volume during and following a degraded core event. (The AP1000 containment volume is large enough to provide passive protection for the hydrogen produced by 75 percent zircaloy cladding reaction following a severe accident.)

- The nonsafety-related ventilation system, normally used during refueling, is designed with the capability for a controlled purge of the containment atmosphere to assist in post-accident cleanup, but is not required for hydrogen control.

Criterion 42 – Inspection of Containment Atmosphere Cleanup System

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic inspection of important components such as filter frames, ducts, and piping, to assure the integrity and capability of the systems.

AP1000 Compliance

The containment atmosphere cleanup systems are designed and located so that they can be inspected periodically, as appropriate.

Criterion 43 – Testing of Containment Atmosphere Cleanup Systems

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leak-tight integrity of its components, (2) the operability and performance of the active components of the systems such as fans, filters, dampers, pumps, and valves, and (3) the operability of the systems as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the systems into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of associated systems.

AP1000 Compliance

The appropriate portions of the containment atmosphere cleanup system are designed to permit periodic pressure and functionality testing.

As described in GDC 41, the containment atmosphere cleanup system has no safety-related post-accident cleanup functions. Dose mitigation is passively provided by the containment isolation and integrity, natural removal processes, and limited containment leakage. Periodic containment integrity is verified in accordance with 10 CFR 50 Appendix J testing as described in subsection 6.2.3.

Criterion 44 – Cooling Water

A system to transfer heat from structures, systems, and components important to safety to an ultimate heat sink shall be provided. The system safety function shall be to transfer the combined heat load of these structures, systems, and components under normal operating and accident conditions.

Suitable redundancy in components and features and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming

onsite power is not available) the system safety function can be accomplished assuming a single failure.

AP1000 Compliance

The passive containment cooling system is the ultimate heat sink for the AP1000 and does not rely upon offsite or onsite ac power sources. Heat transfer by convection from the containment shell to the atmosphere meets the intent of GDC 44. Additional information is provided in the responses for GDC 34 and GDC 38.

Criterion 45 – Inspection of Cooling Water System

The cooling water system shall be designed to permit appropriate periodic inspection of important components, such as heat exchangers and piping, to assure the integrity and capability of the system.

AP1000 Compliance

Refer to the discussion provided for GDC 39.

Criterion 46 – Testing of Cooling Water System

The cooling water system shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leak-tight integrity of its components, (2) the operability and the performance of the active components of the system, and (3) the operability of the system as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation for reactor shutdown and for loss of coolant accidents, including operation of applicable portions of the protection system and the transfer between normal and emergency power sources.

AP1000 Compliance

Refer to the discussion provided for GDC 40.

3.1.5 Reactor Containment

Criterion 50 – Containment Design Basis

The reactor containment structure, including access opening, penetrations, and the containment heat removal system, shall be designed so that the containment structure and its internal compartments can accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated pressure and temperature conditions resulting from any loss of coolant accident. This margin shall reflect consideration of (1) the effects of potential energy sources which have not been included in the determination of the peak conditions, such as energy in steam generators and energy from metal-water and other chemical reactions that may result from degraded emergency core cooling functioning, (2) the limited experience and experimental data available for defining accident phenomena and containment responses, and (3) the conservatism of the calculational model and input parameters.

AP1000 Compliance

The design of the containment structure is based on the containment design basis accidents, which include the rupture of a reactor coolant pipe or the rupture of a main steam or feedwater line. The maximum pressure and temperature reached, a description of the calculational model, and input parameters for a containment design basis accident are presented in Section 6.2. The containment design provides margin to the design basis limits.

Criterion 51 – Fracture Prevention of Containment Pressure Boundary

The reactor containment boundary shall be designed with sufficient margin to assure that under operating, maintenance, testing, and postulated accident conditions (1) its ferritic materials behave in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the containment boundary material during operation, maintenance, testing, and postulated accident conditions, and the uncertainties in determining (1) material properties, (2) residual, steady-state, and transient stresses, and (3) size of flaws.

AP1000 Compliance

Principal load-carrying components of ferritic materials of the reactor containment boundary exposed to the external environment are selected so that they behave in a nonbrittle manner and so that the probability of fracture propagation is minimized. See subsection 3.8.2 for additional information.

Criterion 52 – Capability for Containment Leakage Rate Testing

The reactor containment and other equipment which may be subjected to containment test conditions shall be designed so that periodic integrated leakage rate testing can be conducted at containment design pressure.

AP1000 Compliance

The containment system is designed and constructed and the necessary equipment is provided to permit periodic integrated leakage rate tests according to the requirements of 10 CFR 50, Appendix J.

Criterion 53 – Provisions for Containment Testing and Inspection

The reactor containment shall be designed to permit (1) appropriate periodic inspection of all important areas, such as penetrations, (2) an appropriate surveillance program, and (3) periodic testing at containment design pressure of the leak-tightness of penetrations which have resilient seals and expansion bellows.

AP1000 Compliance

Provisions exist for conducting individual leakage rate tests on containment penetrations. Penetrations are visually inspected and pressure-tested for leak tightness at periodic intervals. Other inspections are performed as required by 10 CFR 50, Appendix J.

Criterion 54 – Piping Systems Penetrating Containment

Piping systems penetrating the primary reactor containment shall be provided with leak detection, isolation and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping systems shall be designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

AP1000 Compliance

Piping systems penetrating the primary reactor containment are provided with containment isolation valves. Penetrations that close for containment isolation have redundant valving. Automatic isolation valves with air-, solenoid-, or motor-operators, which do not restrict normal plant operation, are periodically tested to verify operability.

The AP1000 containment isolation design satisfies the current NRC requirements including the post-TMI requirements, as discussed in subsection 1.9.3. In general, this means that two barriers are provided, one inside containment and the other outside containment. Usually these barriers are valves, but in some cases they are closed piping systems not connected to the reactor coolant system or to the containment atmosphere.

The AP1000 design incorporates a reduction in the number of existing penetrations. Most penetrations are normally closed. Those few that are normally open and are required to close use remotely operated valves for isolation that close automatically. See subsection 6.2.3 for additional information.

Nonessential systems that may be normally open, such as the mini-purge system, are provided with automatic containment isolation valves that close automatically on a containment isolation signal. The containment isolation signal is actuated by the protection and safety monitoring system. See Section 7.3 for additional information.

Piping and electrical containment penetrations are equipped with test connections and test vents or have other provisions to allow periodic leak rate testing so that leakage is within the acceptable limits established in technical specifications consistent with 10 CFR 50, Appendix J.

Criterion 55 – Reactor Coolant Pressure Boundary Penetrating Containment

Each line that is part of the reactor coolant pressure boundary and that penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

1. One locked closed isolation valve inside and one locked closed isolation valve outside containment; or

2. One automatic isolation valve inside and one locked closed isolation valve outside containment; or

3. One locked closed isolation valve inside and one automatic isolation valve outside the containment. A simple check valve may not be used as the automatic isolation valve outside containment; or

4. One automatic isolation valve inside and one automatic isolation valve outside containment. A simple check valve may not be used as the automatic isolation valve outside containment.

Isolation valves outside containment shall be located as close to containment as practical and, upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

Other appropriate requirements to minimize the probability or consequences of an accidental rupture of these lines or of lines connected to them shall be provided, as necessary, to assure adequate safety. Determination of the appropriateness of these requirements, such as higher quality in design, fabrication, and testing, additional provisions for in-service inspection, protection against more severe natural phenomena, and additional isolation valves and containment, shall include consideration of the population density, and use characteristics, and physical characteristics of the site environs.

AP1000 Compliance

Lines that penetrate containment that are connected to the reactor coolant pressure boundary are provided with containment isolation valves in accordance with one of the acceptable arrangements as described in GDC 55. Additional information is found in subsection 6.2.3.

Criterion 56 – Primary Containment Isolation

Each line that connects directly to the containment atmosphere and penetrates the primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:

1. One locked closed isolation valve inside and one locked closed isolation valve outside the containment; or

2. One automatic isolation valve inside and one locked closed isolation valve outside the containment; or

3. One locked closed isolation valve inside and one automatic isolation valve outside the containment. A simple check valve may not be used as the automatic isolation valve outside containment; or

4. One automatic isolation valve inside and one automatic isolation valve outside the containment. A simple check valve may not be used as the automatic isolation valve outside the containment.

Isolation valves outside the containment shall be located as close to the containment as practical and, upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.

AP1000 Compliance

Lines connecting directly with the containment atmosphere and penetrating the reactor containment are normally provided with two isolation valves in series, one inside and one outside the containment, in accordance with one of the acceptable arrangements as described in GDC 56. Additional information is found in subsection 6.2.3.

Criterion 57 – Closed System Isolation Valves

Each line that penetrates the primary reactor containment and is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, locked closed, or capable of remote manual operation. This valve shall be outside the containment and located as close to the containment as practical. A simple check valve may not be used as the automatic isolation valve.

AP1000 Compliance

Lines that penetrate the containment and are neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere are considered closed systems within the containment and are equipped with at least one containment isolation valve of one of the following types:

- An automatic isolation valve (a simple check valve is not used as this automatic valve)

- A locked-closed valve

This valve is located outside the containment and as close to the containment wall as practical.

3.1.6 Fuel and Reactivity Control

Criterion 60 – Control of Releases of Radioactive Materials to the Environment

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for the retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

AP1000 Compliance

Means are provided to control the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences.

The radioactive waste management systems are designed to minimize the potential for an inadvertent release of radioactivity from the facility and to provide confidence that the discharge of radioactive wastes is maintained below regulatory limits of 10 CFR 50, Appendix I, during normal operation. The gaseous radwaste and liquid radwaste processing systems include continuous radiation monitoring of their discharge paths. High radiation automatically closes a discharge isolation valve. The liquid radwaste system also has provisions to prevent inadvertant siphoning of its monitor tank contents which could cause an uncontrolled discharge. The radioactive waste management systems, the design bases, and the estimated amounts of radioactive effluent releases to the environment are described in Chapter 11.

Criterion 61 – Fuel Storage and Handling and Radioactivity Control

The fuel storage and handling, radioactive waste, and other systems which may contain radioactivity shall be designed to assure adequate safety under normal and postulated accident conditions. These systems shall be designed (1) with a capability to permit appropriate periodic inspection and testing of components important to safety, (2) with suitable shielding for radiation protection, (3) with appropriate containment, confinement, and filtering systems, (4) with a residual heat removal capability having reliability and testability that reflects the importance to safety of decay heat and other residual heat removal, and (5) to prevent significant reduction in fuel storage coolant inventory under accident conditions.

AP1000 Compliance

The spent fuel pool cooling system, and the fuel handling and refueling system are designed to provide cooling and shielding for the fuel assemblies stored in the spent fuel pit and to provide purification of the water in the pit. The system design provides adequate safety under normal and postulated accident conditions.

The spent fuel pool cooling system normal system operation is described in subsection 9.1.3. Sampling of the spent fuel pool water for gross activity, tritium, and particulate matter is conducted periodically. The concentration of tritium in the spent fuel pool water is maintained at

less than 0.5 microcuries per gram to provide confidence that the airborne concentration of tritium in the fuel handling area is within the limits specified in 10 CFR 20, Appendix B. See subsection 12.2.2 for additional information.

The spent fuel pool is designed so that a water level is maintained above the spent fuel assemblies for at least 72 hours following a loss of the spent fuel pool cooling system, without ac power or makeup water. See subsection 9.1.2 for additional information.

The spent fuel pool cooling system maintains the water in the in-containment refueling water storage tank consistent with activity requirements of the water in the refueling cavity during a refueling. Two spent fuel pool cooling filters are provided, one downstream of each demineralizer in the purification branch line of each mechanical train. The filters are sized to collect particulates and suspended solids passed by the demineralizer.

The AP1000 spent fuel pool cooling system is not required to operate to mitigate design basis events. In the event the spent fuel pool cooling system is unavailable, the spent fuel pool cooling is provided by the heat capacity of the water in the pool.

Normal HVAC to the spent fuel pool area is provided by a subsystem of the radiologically controlled area ventilation system described in subsection 9.4.3. No credit is taken for this system in evaluation of fuel handling accidents discussed in subsection 15.7.4.

Connections to the spent fuel pool are provided at an elevation that prevents inadvertent draining of the water in the pool to an unacceptable level.

The design of spent fuel storage pool and the spent fuel pool cooling system satisfies GDC 61. See subsection 9.1.3 for additional information.

Criterion 62 – Prevention of Criticality in Fuel Storage and Handling

Criticality in the fuel storage and handling system shall be prevented by physical systems or processes, preferably by use of geometrically safe configurations.

AP1000 Compliance

The restraints, interlocks, and physical arrangement provided for the safe handling and storage of new and spent fuel are discussed in Section 9.1. The spent fuel assemblies are stored in the spent fuel pit until fission product activity is low enough to permit shipment.

Criterion 63 – Monitoring Fuel and Waste Storage

Appropriate systems shall be provided in the fuel storage and radioactive waste systems and associated handling areas (1) to detect conditions that may result in the loss of residual heat removal capability and excessive radiation levels and (2) to initiate appropriate safety actions.

AP1000 Compliance

Instrumentation is provided to monitor spent fuel storage pool temperature and water level. Indication and alarms are provided in the main control room. Area radiation monitoring is provided in the fuel storage area for personnel protection and general surveillance. The area monitor alarms locally and in the main control room.

If radiation levels in the ventilation effluent reach a predetermined point, an alarm is actuated in the main control room, and the ventilation discharge path is automatically transferred through filter absorber units that provide filtration before discharge from the plant vent.

Criterion 64 – Monitoring Radioactivity Releases

Means shall be provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of loss of coolant accident fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

AP1000 Compliance

The containment atmosphere is monitored during normal and transient operations by the containment gaseous radiation monitors. Under accident conditions, samples of the containment atmosphere taken via the sampling system provide data on airborne radioactive concentrations within the containment.

No reactor coolant fluids are required to be recirculated outside of containment following an accident. Radioactivity levels contained in the facility effluent and discharge paths and in the plant environs are monitored during normal and accident conditions by the plant radiation monitoring systems. High radiation in a discharge path causes automatic closure of the discharge isolation valve.

Area radiation monitors (ARMs) are provided to supplement the personnel and area radiation survey provisions of the AP1000 health physics program described in Section 12.5 and to comply with the personnel radiation protection guidelines of 10 CFR 20, 10 CFR 50, 10 CFR 70, and Regulatory Guides 1.97, 8.2, 8.8, and 8.12. In addition to the installed detectors, periodic plant environmental surveillance is established.

Measurement capability and reporting of effluents are based on the guidelines of Regulatory Guides 1.4 and 1.21, as discussed in subsection 1.9.1. Additional information is contained in Chapters 11 and 12.

3.1.7 Combined License Information

This section has no requirement for additional information to be provided in support of the Combined License application.

3.1.8 References

1. 10 CFR 50, Appendix G, "Fracture Toughness Requirements."

2. American Society of Testing Materials E-185, Standard Recommended Practice for Surveillance Test for Nuclear Reactor Vessels, and the requirements for 10 CFR 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements."

3.2 Classification of Structures, Components, and Systems

Structures, systems, and components in the AP1000 are classified according to nuclear safety classification, quality groups, seismic category, and codes and standards. This section provides the methodology used for safety-related and seismic classification of AP1000 structures, systems, and components. The seismic classification is described in subsection 3.2.1. Subsection 3.2.2 describes the classification including nuclear safety-related classification and the corresponding codes and standards. Additionally, subsection 3.2.2 describes nonsafety-related equipment classifications.

3.2.1 Seismic Classification

General Design Criterion 2 requires that nuclear power plant "Structures, systems, and components important to safety shall be designed to withstand the effects of natural phenomena, such as earthquakes, tornados, hurricanes, floods, tsunami, and seiches without loss of capability to perform their safety functions." 10 CFR 100, Appendix A sets forth the criteria to which the plant design bases demonstrate the capability to function during and after vibratory ground motion associated with the safe shutdown earthquake conditions.

The seismic classification methodology used in AP1000 complies with the preceding criteria, as well as with recommendations stated within Regulatory Guide 1.29. Conformance with the recommendations of Regulatory Guide 1.29 is discussed in subsection 1.9.1. The methodology classifies structures, systems, and components into three categories: seismic Category I (C-I), seismic Category II (C-II) and non-seismic (NS).

Seismic Category I applies to both functionality and integrity, and seismic Category II applies only to integrity. Non-seismic items located in the proximity of safety-related items, the failure of which during a safe shutdown earthquake could result in loss of function of safety-related items, are designated as seismic Category II.

3.2.1.1 Definitions

3.2.1.1.1 Seismic Category I (C-I)

Seismic Category I applies to, in general, safety-related structures, systems, and components, Seismic Category I also applies to those structures, systems, and components required to support or protect safety-related structures, systems, and components. The exceptions to this general rule are a limited number of structures, such as those required for tornado missile protection, which do not have a safety-related function to perform during or following a seismic event. (See subsection 3.2.2.3.)

Safety-related items are those necessary to provide for the following:

- The integrity of the reactor coolant pressure boundary
- The capability to shut down the reactor and maintain it in a safe shutdown condition

- Capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guideline exposures of 10 CFR 100.

Seismic Category I structures, systems, and components are designed to withstand the appropriate seismic loads, as discussed in Section 3.7, and other applicable loads without loss of function. Seismic Category I structures are protected from interaction with adjacent non-seismic structures as described in subsection 3.7.2.8.

Seismic Category I structures, systems, and components meet the quality assurance requirements of 10 CFR 50, Appendix B. The criteria used for the design of seismic Category I structures, systems, and components are discussed in Section 3.7.

3.2.1.1.2 Seismic Category II (C-II)

Seismic Category II applies to plant structures, systems, and components which perform no safety-related function, and the continued function of which is not required. Seismic Category II applies to structures, systems, and components designed to prevent their collapse under the safe shutdown earthquake. Structures, systems and components are classified as seismic Category II to preclude their structural failure during a safe shutdown earthquake or interaction with seismic Category I items which could degrade the functioning of a safety-related structure, system, or component to an unacceptable level, or could result in incapacitating injury to occupants of the main control room.

Seismic Category II structures, systems, and components are designed so that the safe shutdown earthquake does not cause unacceptable structural failure of or interaction with seismic Category I items. Seismic Category II fluid systems require an appropriate level of pressure boundary integrity if located near sensitive equipment.

The criteria used for the design of seismic Category II structures, systems, and components are discussed in Section 3.7.

Pertinent portions of 10 CFR 50, Appendix B apply to seismic Category II structures, systems, and components. The quality assurance requirements for seismic Category II structures, systems, and components are sufficient to provide that these components will meet the requirement to not cause unacceptable structural failure of or interaction with seismic Category I items. See Section 17.4 for the Combined License applicant quality assurance program requirement.

3.2.1.1.3 Non-Seismic

Non-seismic (NS) structures, systems, and components are those that are not classified seismic Category I or Category II.

The criteria used for the design of non-seismic structures, components and systems are discussed in Section 3.7.

The non-seismic lines and associated equipment are routed, to the extent practicable, outside of safety-related buildings and rooms to avoid adverse system interactions. In cases where these lines are routed in safety-related areas, the non-seismic item is evaluated for the safe shutdown

earthquake and is upgraded to seismic Category II if a credible failure could cause an unacceptable interaction.

Although the seismic category for an item located in the proximity of safety-related structures, systems, and components may be upgraded to seismic Category II, its pre-assigned equipment class remains unchanged.

3.2.1.2 Classifications

Table 3.2-1 illustrates the general relationship between safety-related equipment classes and seismic categories. In most cases, except as noted in subsection 3.2.2.5, safety-related items are also seismic Category I items. When portions of systems are identified as seismic Category I, the boundaries of seismic Category I portions of the system are shown on the piping and instrumentation diagram (P&ID) of that system. See subsection 1.7.2 for a list of the piping and instrumentation diagrams.

3.2.1.3 Classification of Building Structures

Building structures are assigned a seismic category as indicated in Table 3.2-2. Codes and standards used in the design and construction of building structures are given in Section 3.8. The building structures are not assigned a safety classification in subsection 3.2.2 with the exception of the containment vessel.

3.2.2 AP1000 Classification System

The assignment of safety-related classification and use of codes and standards conforms to the requirements of 10 CFR 50.55a for the development of a Quality Group classification and the use of codes and standards. The description of the equipment classification which follows identifies the classifications requiring the full 10 CFR 50, Appendix B quality assurance program as described in Chapter 17 and the Quality Group associated with each classification.

The classification system provides a means of identifying the extent to which structures, systems, and components are related to safety-related and seismic requirements. The classification system provides an easily recognizable means of identifying the extent to which structures, systems, and components are related to ANS nuclear safety classification, NRC quality groups, ASME Code, Section III classification, seismic category and other applicable industry standards, as shown in Table 3.2-3.

3.2.2.1 Classification Definitions

The definitions used in the classification of structures, systems and components are provided in the following. Unless otherwise noted these definitions apply throughout the Design Control Document. These definitions are consistent with the draft ANS Definitions for Light Water Reactor Standards.

Safety-related is a classification applied to items relied upon to remain functional during or following a design basis event to provide a safety-related function. Safety-related also applies to documentation and services affecting a safety-related item.

Safety-related function is a function that is relied upon during or following a design basis event to provide for the following:

- The integrity of the reactor coolant pressure boundary
- The capability to shut down the reactor and maintain it in a safe shutdown condition
- The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guideline exposures of 10 CFR 100.

Design basis event is an event that is a condition of normal operation (including anticipated operational occurrences), a design basis accident, an external event, or natural phenomena for which the plant must be designed so that the safety-related functions are achievable.

Design basis accidents and transients are those design basis events that are accidents and transients and are postulated in the safety analyses. The design basis accidents and transients are used in the design of the plant to establish acceptable performance requirements for structures, systems, and components.

3.2.2.2 Application of Classification

The AP1000 requires adaptation of safety classification documents and standards because of the way that the AP1000 accomplishes safety-related functions.

In addition to 10 CFR 50.55a, the AP1000 classification has been developed considering requirements and guidelines in the following:

- ANSI N18.2 (Reference 1) – safety classification
- ANS 51.1 (Reference 2) – safety classification
- Regulatory Guide 1.26 – Quality Groups
- Regulatory Guide 1.97 – instrumentation requirements
- 10 CFR 21.

Conformance with the guidelines of Regulatory Guides 1.26 and 1.97 is discussed in subsection 1.9.1.

The general guidelines for safety classification in the ANSI and ANS standards are useful in the development of the AP1000 classification. The specific classifications for various structures, systems, and components included in Regulatory Guide 1.26 and ANSI 18.2 and ANS 51.1 are based on a nuclear power plant with active safety systems and are not necessarily appropriate for the passive safety systems of the AP1000.

For the purposes of equipment classification, structures, systems, and components are classified as Class A, B, C, D, E, F, L, P, R, or W. For mechanical equipment Classes A, B, and C are equivalent to ANS Safety Class 1, 2, and 3. For electrical equipment Class C is equivalent to Class 1E. Structures, systems, and components classified equipment class A, B, or C or seismic Category I are basic components as defined in 10 CFR Part 21.

Equipment Class D is a nonsafety-related class. Classes E, F, L, P, R, and W are nonsafety-related classes associated with different industry codes and standards.

Components are classified down to the replacement part level according to the definitions and criteria of the classification system. A single item or portion thereof, which provides two or more functions of different classes, is classified according to the most stringent function. Different portions of the same structure, system, or component may perform different functions and be assigned to different equipment classes if the structure, system, and component contains a suitable interface boundary.

The definitions and criteria for the AP1000 equipment classes follow.

3.2.2.3 Equipment Class A

Class A is a safety-related class equivalent to ANS Safety Class 1. It applies to the reactor coolant system pressure boundary, including the required isolation valves and mechanical supports. This class has the highest integrity, and the lowest probability of leakage.

10 CFR 21 applies to Class A structures, systems, and components. Class A structures, systems, and components are seismic Category I and use codes and standards consistent with the guidelines for NRC Quality Group A. 10 CFR 50, Appendix B and ASME Code, Section III, Class 1 apply.

3.2.2.4 Equipment Class B

Class B is a safety-related class equivalent to ANS Safety Class 2. It limits the leakage of radioactive material from the containment following a design basis accident. This class is designed to accomplish the following:

- It provides fission product barrier or primary containment radioactive material holdup or isolation.

- It provides the containment boundary including penetrations and isolation valves. This also includes piping that functions as the containment boundary. For example, the steam and feedwater system inside containment and the secondary shell of the steam generator are Class B by this criterion.

- It circulates a non-containment/non-reactor coolant fluid to provide a post-accident safety-related function into and out of the containment. These lines have a Class B pressure boundary inside the containment. The outside containment lines in this circulation loop can be Class C or a nonsafety-related class if suitable containment isolation valves are provided.

- It introduces emergency negative reactivity to make the reactor subcritical (for example, control rods).

- This class also applies to structures, systems, and components where leakage could cause a loss of adequate core cooling. In isolating leaks, credit can be taken for automatic safety-related isolation and for appropriate operator action. As a minimum, operator action needs redundant safety-related indication and alarm followed by 30 minutes for operator action.

10 CFR 21 applies to Class B structures, systems, and components. Class B structures, systems, and components are seismic Category I and use codes and standards consistent with the guidelines for NRC Quality Group B. 10 CFR 50, Appendix B, and ASME Code, Section III, Class 2 or Class MC apply. ASME Code, Section III, Subsection NE applies to the containment vessel and guard pipes.

3.2.2.5 Equipment Class C

Class C is a safety-related class equivalent to ANS Safety Class 3. It applies to other safety-related functions required to mitigate design basis accidents and other design basis events. Minor leakage will not prevent Class C structures, systems, and components from meeting the safety-related function, either from the regard of radiation dose or system functioning.

This class also applies to equipment that, upon rupturing, would cause dose limits for unrestricted areas, as specified in 10 CFR 20, to be exceeded or would cause a loss of core cooling.

10 CFR 21 applies to Class C structures, systems, and components. Class C structures, systems, and components use codes and standards consistent with the guidelines for NRC Quality Group C. Class C structures, systems, and components are seismic Category I except those noted below which are not required to provide a safety-related function following a seismic event. 10 CFR 50, Appendix B and ASME Code, Section III, Class 3 apply. In addition to these requirements, for systems that provide emergency core cooling functions, full radiography in accordance with the requirements of ASME Code, Section III, ND-5222 will be conducted on the piping butt welds during construction. For Class C air and gas storage tanks fabricated without welding, ASME Code, Section VIII, Appendix 22 may be used in lieu of Section III, Class 3. 10 CFR 50, Appendix B requirements and 10 CFR 21 apply to the manufacture of safety-related air and gas storage tanks. For core support structures ASME Code, Section III, Subsection NG applies. For electrical systems, appropriate IEEE standards, including IEEE standard 323-74 (Reference 3) and IEEE standard 344-87 (Reference 4), apply.

Class C applies to structures, systems, and components not included in Class A or Class B that are designed and relied upon to accomplish one or more of the following safety-related functions:

- Provide safety injection or maintain sufficient reactor coolant inventory to allow for core cooling
- Provide core cooling
- Provide containment cooling
- Provide for removal of radiation from the containment atmosphere as necessary to meet the offsite dose limits
- Limit the buildup of radioactive material in the atmosphere of rooms and areas outside containment as necessary to meet the offsite dose limits

- Introduce negative reactivity control measures to achieve or maintain safe shutdown conditions (for example, boron addition)

- Limit the buildup of hydrogen in the containment atmosphere to acceptable values

- Maintain geometry of structures inside the reactor vessel so that the control rods can be inserted (when required) and the fuel remains in a coolable geometry

- Provide load-bearing structures and supports for Class A, B, and C structures, systems, and components. This applies to structures and supports that are not part of the pressure boundary.

- Provide structures and buildings to protect Class A, B, and C structures, systems, and components from events such as internal/external missiles, seismic, and flooding. Structures protecting equipment from nonseismic events are not required to be seismic Category I.

- Provide permanent radiation shielding to allow operator access to the main control room and to limit the exposure to Class A, B and C structures, systems, and components

- Provide safety support functions to Class A, B and C structures, systems, and components, such as, heat removal, room cooling, and electrical power

- Provide instrumentation and controls for automatic or manual actuation of Class A, B, and C structures, systems, and components necessary to perform the safety-related functions of the Class A, B, or C structure, system or component. This includes the processing of signals and interlock functions required for proper safety performance of these structures, systems, and components.

- Handle spent fuel, the failure of which could result in fuel damage such that significant quantities of radioactive material could be released from the fuel and results in offsite doses greater than normal limits (for example, new and spent fuel racks, the bridge, and the hoist)

- Maintain spent fuel sub-critical

- Monitor radioactive effluent to confirm that release rates or total releases are within limits established for normal operations and transient operation

- Monitor variables to indicate status of Class A, B or C structures, systems, and components required for post-accident mitigation

- Provide for functions defined in Class B where structures, systems, and components, or portions thereof are not within the scope of the ASME Code, Section III, Class 2.

- Provide provisions for connecting temporary equipment to extend the use of safety related systems. See subsection 1.9.5 for a discussion of actions required for an extended loss of onsite and offsite ac power sources.

The components and portions of systems that provide emergency core cooling functions and are required to have radiography of a random sample of welds during construction include the following:

- Accumulators
- Injection piping from the accumulators to the reactor coolant system isolation check valves in the direct vessel injection line
- Piping from the in-containment refueling water storage tank (IRWST) and recirculation screens to the reactor coolant system isolation check valves in the direct vessel injection line
- Piping from the Stage 1, 2, and 3 automatic depressurization system valves to the IRWST including the spargers.

The IRWST is formed from portions of structural modules that are elements of the containment internal structures. The inspection requirements for the welds in these structural modules are provided in subsection 3.8.3.6.2.

3.2.2.6 Equipment Class D

Class D is nonsafety-related with some additional requirements on procurement, inspection or monitoring.

For Class D structures, systems, and components containing radioactivity, it is demonstrated by conservative analysis that the potential for failure due to a design basis event does not result in exceeding the normal offsite doses per 10 CFR 20. This criterion is in conformance with the definition of Class D in Regulatory Guide 1.26.

A structure, system or component is classified as Class D when it directly acts to prevent unnecessary actuation of the passive safety systems. Structures, systems and components which support those which directly act to prevent the actuation of passive safety systems are also Class D. The inclusion of these nonsafety-related structures, systems, and components in Class D recognizes that these systems provide an important first level of defense that helps to reduce the calculated probabilistic risk assessment core melt frequency. These structures, systems, and components are normally used to support plant cooldown and depressurization and to maintain shutdown conditions during maintenance and refueling outages.

For Class D structures, systems, and components considered to be risk significant as defined in the reliability assurance program (see Section 16.2). Provisions are made to check for operability, including appropriate testing and inspection, and to repair out-of-service structures, systems, and components. These provisions are documented and administered in the plant reliability assurance plan and operating and maintenance procedures.

A portion of chemical and volume control system is defined as the reactor coolant pressure boundary and is Class D. This portion of the chemical and volume control system is seismically analyzed. See subsection 5.2.1.1 for the seismic analysis requirements.

Some Class D structures, systems, and components are assumed to function in a severe containment environment. The design requirements for these components include operation in such an environment. An evaluation is done to confirm that the structure, system, or component can be expected to function in such an environment.

Standard industrial quality assurance standards are applied to Class D structures, systems, and components to provide appropriate integrity and function although 10 CFR 50, Appendix B and 10 CFR 21 do not apply. 10 CFR 50, Appendix B and 10 CFR 21 do apply to Class D structures, systems, and components that are seismic Category I. These industrial quality assurance standards are consistent with the guidelines for NRC Quality Group D. The industry standards used for Class D structures, systems and components are widely used industry standards. Typical industrial standards used for Class D systems and components are provided as follows:

- Pressure vessels – ASME Code, Section VIII
- Piping – ANSI B 31.1. Power Piping, (Reference 5)
- Pumps – API 610 (Reference 6), or Hydraulic Institute Standards (Reference 7)
- Valves – ANSI B16.34 (Reference 8)
- Atmospheric storage tanks – API-650 (Reference 9), AWWA D 100 (Reference 10), or ANSI B96.1 (Reference 11)
- 0 - 15 psig Storage Tanks – API-620 (Reference 12)
- AC motor and generators – NEMA MG1 (Reference 13)
- Circuit breakers, switchgear, relays, substations and fuses – IEEE C37 (Reference 14).

The buildings containing Class D structures, systems, and components, as well as the anchorage of the structures, systems, and components to the building, are designed to the seismic requirements of the Uniform Building Code (Reference 15). The systems and components are not designed for seismic loads. However, when Class D structures, systems, and components are located near a Class A, B, or C structure, system, or component, the requirements for seismic Category II may apply.

For Class D structures, systems, and components required to be monitored for maintenance effectiveness by 10 CFR 50.65, the availability parameters and criteria are included in the maintenance monitoring plan for evaluating the effectiveness of the maintenance program.

As examples, Class D applies to structures, systems, and components not included in Class A, B or C that provide the following functions:

- Provide core or containment cooling which prevents challenges to the passive core cooling system and the passive containment cooling system

- Process, extract, encase, store or reuse radioactive fluid or waste
- Verify that plant operating conditions are within technical specification limits
- Provide permanent shielding for post accident access to Class A, B or C structures, systems, and components or of offsite personnel
- Handle spent fuel, the failure of which could result in fuel damage such that limited quantities of radioactive material could be released from the fuel such as fuel handling tools
- Protect Class B or C structures, systems, and components necessary to attain or maintain safe shutdown following fire
- Indicate the status of protection system bypasses that are not automatically removed as a part of the protection system operation
- Aid in determining the cause or consequences of an event for post-accident investigation
- Prevent interaction that could result in preventing Class A, B or C structures, systems, and components from performing required safety-related functions

3.2.2.7 Other Equipment Classes

Equipment classes E, F, L, P, R, and W are nonsafety-related. They apply to structures, systems, and components not covered in the above classes. They have no safety-related function to perform. They do not contain sufficient radioactive material that a release could exceed applicable limits.

Structures, systems, and components that do not normally contain radioactive fluids, gases, or solids but have the potential to become radioactively contaminated are classified as one of these nonsafety-related classes if all of the following criteria are satisfied:

- The system is only potentially radioactive and does not normally contain radioactive material, and
- The system has shown in plant operations that the operation with the system containing radioactive material meets or can meet unrestricted area release limits, and
- An evaluation of the system confirms that the system contains features and components that keep the consequences of a system failure as low as reasonably achievable, and
- The system has no other regulatory guidance requiring its inclusion in Classes A, B, C or D.

This review of the system features and components includes the following as a minimum:

- Features and components that control and limit the radioactive contamination in the system

- Features that facilitate an expeditious cleanup should the system become contaminated

- Features and components that limit and control the radiological consequences of a potential system failure

- The means by which the system prevents propagation to an event of greater consequence.

There are no special quality assurance requirements for Class E, F, L, P, R, and W structures, systems, and components. Unless specifically specified, 10 CFR Part 21 and Part 50, Appendix B do not apply. The systems and components are normally not designed for seismic loading. However, there may be special cases where some seismic design is required. See subsection 3.2.1 for more details.

Structures, systems, and components are designed in accordance with an industry standard at the discretion of the designer. The following provides examples of industry standards which may be used for these classes:

Class E – This class is used for nonsafety-related structures, systems, and components that do not have a specialized industry standard or classification, as noted in the following classes.

Class F – This class is used for Fire Protection Systems. It complies with National Fire Protection Association Codes which invoke ANSI B31.1 (Reference 5), AWWA (American Water Works Association), API (American Petroleum Institute), Underwriters Laboratories (UL), and other codes, depending on service. See subsection 9.5.1 for quality assurance requirements for fire protection structures, systems, and components. In some cases fire protection systems are designated as AP1000 equipment **Class G**.

Class L – This class is used in heating, ventilation and air-conditioning systems. It complies with SMACNA - 1985 (Reference 16). Components may also be procured to AMCA and ASHRAE standards.

Class P – This class is used for plumbing equipment. It complies with the National Plumbing Code (Reference 17).

Class R – This class is for air cleaning units and components that may be required to contain, clean, or exclude radioactively contaminated air. It complies with ASME 509 (Reference 18). When used with 10 CFR Part 50 Appendix B quality assurance, it is equivalent to Class C.

Class W – This class complies with American Water Works Association guidelines with no specific quality assurance requirements.

3.2.2.8 Instrumentation and Control Line Interface Criteria

Class C instrumentation, as defined in subsection 3.2.2.5 have a safety-related equipment class pressure boundary including the sensing line, valves and instrument sensor. The pressure boundary is the same safety-related equipment class as the systems or components it is connected to. Sensing lines connected to the reactor coolant system pressure boundary are Class B if a suitable flow restrictor is provided.

The parts of the sensor, outside the pressure boundary, are designated Class C (1E) if they provide a safety-related function per subsection 3.2.2.1. They are Class D if the instrument supports Class D functions per subsection 3.2.2.6. Otherwise the parts are Class E.

3.2.2.9 Electrical Classifications

Safety-related electrical equipment is equipment Class C, as outlined in subsection 3.2.2.5, and is constructed to IEEE standards for Class 1E. The nonsafety-related electrical equipment and instrumentation is constructed to standards including non-Class 1E IEEE standards and National Electrical Manufacturers Association (NEMA) standards. Safety-related electrical equipment and instrumentation is identified in Section 3.11.

3.2.3 Inspection Requirements

Safety-related structures, systems, and components built to the requirements of the ASME Code, Section III, are required by 10 CFR 50.55a to have in-service inspections. The requirements of the in-service inspection program for ASME Code, Section III structures, systems, and components are found in Section XI of the ASME Code.

The following ASME standards apply to safety-related structures, systems, and components:

- Pumps (Class A, B, C) – ASME Code, Section XI, Subsection IWP
- Valves (Class A, B, C) – ASME Code, Section XI, Subsection IWV
- Equipment supports (Class A, B, C) – ASME Code, Section XI, Subsection IWF
- Metal containments and vessels – ASME Code, Section XI, Subsection IWE
- Other Class A components such as pipes and tanks – ASME Code, Section XI, Subsection IWB
- Other Class B components such as pipes and tanks – ASME Code, Section XI, Subsection IWC
- Other Class C components such as pipes and tanks – ASME Code, Section XI, Subsection IWD.

The inspection requirements, if applicable, for Class D structures, systems, and components are established by the designer for each structure, system, and component. These inspection requirements are developed so that the reliability of the structures, systems, and components is not degraded. The inspection requirements are included in the administratively controlled inspection or maintenance plans.

3.2.4 Application of AP1000 Safety-Related Equipment and Seismic Classification System

The application of the AP1000 equipment and seismic classification system to AP1000 systems and components is shown in Table 3.2-3. Table 3.2-3 lists safety-related and seismic Category I

mechanical and fluid system component and associated equipment class and seismic category as well as other related information. The table also provides information on the systems that contain Class D components. Additional information on the Class D functions of the various systems can be found in the description in the Design Certification Document (DCD) for the systems. Mechanical and fluid systems that contain no safety-related or Class D systems are included in the table and general information provided on the system. Supports for piping and components have the same classification as the component or piping supported. Supports for AP1000 equipment Class A, B, and C mechanical components and piping are constructed to ASME Code, Section III, Subsection NF requirements. The principal construction code for supports for nonsafety-related components and piping is the same as that for the supported component or piping.

Following the name of each system is the building location of the system components. Some of the systems supply all or most of the buildings. This is indicated by identifying the location as various. Where a system includes piping or ducts that only passed through a building without including any components that building is generally not included in the list.

The following list includes the systems in Table 3.2-3. The three letters in the beginning of each line is the acronym for the system. The systems included in Table 3.2-3 are listed alphabetically by three letter acronym. Those systems marked with an asterisk * are electrical or instrumentation systems and are not included in Table 3.2-3. The components in the incore instrumentation system that have a pressure boundary function are included in the table. See Section 3.11 for identification of safety-related electrical and instrumentation equipment.

NSSS/Steam Generator Controls and Auxiliaries

BDS	Steam Generator Blowdown System
CNS	Containment System
CVS	Chemical and Volume Control System
PCS	Passive Containment Cooling System
PXS	Passive Core Cooling System
RCS	Reactor Coolant System
RNS	Normal Residual Heat Removal System
RXS	Reactor System
SGS	Steam Generator System

Nuclear Control and Monitoring

*DAS	Diverse Actuation System
IIS	Incore Instrumentation System
*OCS	Operation and Control Centers
*PMS	Protection and Safety Monitoring System
PSS	Primary Sampling System
*RMS	Radiation Monitoring System
*SJS	Seismic Monitoring System
*SMS	Special Monitoring System

Main Power Cycle and Auxiliaries

CDS	Condensate System
CFS	Turbine Island Chemical Feed System

CPS	Condensate Polishing System
DTS	Demineralized Water Treatment System
DWS	Demineralized Water Transfer and Storage System
FWS	Main and Startup Feedwater System
GSS	Gland Seal System
HDS	Heater Drain System
MSS	Main Steam System
MTS	Main Turbine System
RWS	Raw Water System
TDS	Turbine Island Vents, Drains and Relief System

Class 1E and Emergency Power Systems

*IDS	Class 1E dc and UPS System

Cooling and Circulating Water

CCS	Component Cooling Water System
CES	Condenser Tube Cleaning System
CWS	Circulating Water System
SFS	Spent Fuel Pit Cooling System
SWS	Service Water System
TCS	Turbine Building Closed Cooling Water System

Auxiliary Steam

ASS	Auxiliary Steam Supply System

Generation and Transmission

*ZAS	Main Generation System
*ZBS	Transmission Switchyard and Offsite Power System
*ZVS	Excitation and Voltage Regulation System

Radwaste

WGS	Gaseous Radwaste System
WLS	Liquid Radwaste System
WRS	Radioactive Waste Drain System
WSS	Solid Radwaste System

HVAC

VAS	Radiologically Controlled Area Ventilation System
VBS	Nuclear Island Nonradioactive Ventilation System
VCS	Containment Recirculation Cooling System
VES	Main Control Room Emergency Habitability System
VFS	Containment Air Filtration System
VHS	Health Physics and Hot Machine Shop HVAC System
VLS	Containment Hydrogen Control System
VRS	Radwaste Building HVAC System
VTS	Turbine Building Ventilation System
VUS	Containment Leak Rate Test System

VWS	Central Chilled Water System
VXS	Annex/Auxiliary Nonradioactive Ventilation System
VYS	Hot Water Heating System
VZS	Diesel Generator Building Ventilation System

Turbine-Generator Controls and Auxiliary

CMS	Condenser Air Removal System
HCS	Generator Hydrogen and CO_2 Systems
HSS	Hydrogen Seal Oil System
LOS	Main Turbine and Generator Lube Oil System
*TOS	Main Turbine Control and Diagnostics System

Material Handling

FHS	Fuel Handling and Refueling System
MHS	Mechanical Handling System

Piping Services

CAS	Compressed and Instrument Air Systems
DOS	Standby Diesel and Auxiliary Boiler Fuel Oil System
FPS	Fire Protection System
PGS	Plant Gas Systems
PWS	Potable Water System

Non-Class 1E Power Systems

*ECS	Main AC Power System
*EDS	Non-Class 1E dc and UPS System
ZOS	Onsite Standby Power System

Miscellaneous Electrical Systems

*EFS	Communication Systems
*EGS	Grounding and Lightning Protection System
*EHS	Special Process Heat Tracing System
*ELS	Plant Lighting System
*EQS	Cathodic Protection System

Non-Nuclear Controls and Monitoring

*DDS	Data Display and Processing System
*MES	Meteorological and Environmental Monitoring System
*PLS	Plant Control System
*SES	Plant Security System
SSS	Secondary Sampling System
*TVS	Closed Circuit TV System

Non-Radioactive Drains

DRS	Storm Drain System
RDS	Gravity and Roof Drain Collection System

SDS Sanitary Drainage System
WWS Waste Water System

Those systems marked with an asterisk (*) are electrical or instrumentation systems and are not included in Table 3.2-3.

3.2.5 Combined License Information

This section contains no requirement for additional information to be provided in support of the Combined License application.

3.2.6 References

1. ANSI N18.2a-75, “Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants.”

2. ANS/ANSI 51.1-83, “Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants.”

3. IEEE 323-74, “IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations.”

4. IEEE 344-1987, “IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations.”

5. ASME/ANSI B31.1-1989, “Power Piping, ASME Code for Pressure Piping.”

6. API 610-81, “Centrifugal Pumps for General Refinery Services.”

7. “Hydraulic Institute Standards,” 1975, Hydraulic Institute.

8. ASME/ANSI B16.34-81, “Valves - Flanged and Buttwelding End.”

9. API-650-80, “Welded Steel Tanks for Oil Storage,” Revision 1, February 1984.

10. AWWA D100-84, “Welded Steel Tanks for Water Storage.”

11. ANSI B96.1-81, “Welded Aluminum-Alloy Storage Tanks.”

12. API-620-82, “Recommended Rules for Design and Construction of Large, Welded, Low-Pressure Storage Tanks,” Revision 1, April 1985.

13. NEMA MG-1-98, “Motors and Generators,” Revision 1, January 1998, National Electric Manufacturers Association.

14. IEEE C37, IEEE standards on circuit breakers, switch gear, relays, substations, fuses, etc.

15. “Uniform Building Code (1997),” International Conference of Building Officials.

16. SMACNA - 1995, HVAC Duct Construction Standards - Metal and Flexible, 1985 Edition, Sheet Metal and Air-Conditioning Contractors National Association.

17. The BOCA Basis/National Plumbing Code 1984: Model Plumbing Regulations for the Protection of Public Health, Safety and Welfare: Sixth Edition, Building Officials and Code Administrators International.

18. ASME/ANSI AG-1-1997, "Code on Nuclear Air and Gas Treatment."

Table 3.2-1

COMPARISON OF SAFETY CLASSIFICATION REQUIREMENTS

AP1000 Code Letter (1)	ANS Equipment Safety Class (2)	RG 1.29 Seismic Design Reqmnts (3)	ASME Code, Sec. III Class (4)	IEEE Requirements	RG 1.26 NRC Quality Group (5)	10 CFR 50 Appendix B (6)	Inspection & Testing Requirements	Required Test & Maint.
A	SC-1	I	1	NA	GROUP A	YES	YES(7)	(8)
B	SC-2	I	2	NA	GROUP B	YES	YES(7)	(8)
C	SC-3	I	3	1E	GROUP C	YES	YES(7)	(8)
D	NNS(2)	NA(9)	NA(10)	(10)	GROUP D	NO(10)	YES(11)	(11)
OTHER	NNS(2)	NA(13)	NA	NA	NA	NA(12)	NA	NA

NA - Not Applicable

OTHER includes Classes E, F, L, P, R, and W.

Notes:

1. A single letter equipment classification identifies the safety class, quality group, and other classifications for AP1000. See the subsection 3.2.2 for definition.
2. AP1000 safety classification is an adaptation of that defined in ANSI 51.1. The NNS defined in the ANSI 51.1 standard is divided into several AP1000 equipment classifications namely, Classes D E, F, L, P, R, and W.
3. See subsection 3.2.1 for definition of seismic categories.
4. ASME Boiler and Pressure Vessel Code, Section III defines various classes of structures, systems, and components for nuclear power plants. It defines criteria and requirements based on the classification. It is not applicable for nonsafety-related components.
5. The quality group classification corresponds to those provided in Regulatory Guide 1.26.
6. “Yes” means quality assurance program is required according to 10 CFR 50 Appendix B.
   “No” means quality assurance program is not required according to 10 CFR 50 Appendix B.
7. Class A, B, and C, structures, systems, and components built to ASME Code, Section III are inspected to ASME Code, Section XI requirements. See the text for additional specification of requirements.
8. Class A, B, and C structures, systems, and components that are required to function to mitigate design base accidents have some testing requirements included in the plant technical specifications. In addition to the requirements in the technical specifications, testing and maintenance requirements are included in an administratively controlled reliability assurance plan.
9. See subsection 3.2.1 for cases when seismic Category II requirements are applicable for Class D structures, systems, and components.
10. See the text for a discussion of the industry standards used in the construction of Class D structures, systems and components.
11. Class D structures, systems, and components have selected reliability assurance programs and procedures to provide availability when needed. These programs are administratively controlled programs and are not included in the technical specifications.
12. Normal industrial procedures are followed in procuring, designing, fabricating, and testing these nonsafety-related structures, systems, and components.
13. Some Class E, F, L, P, R, and W structures, systems, and components may be classified as seismic Category II. See subsection 3.7.3.

Table 3.2-2

SEISMIC CLASSIFICATION OF BUILDING STRUCTURES

Structure	Category
Nuclear Island Basemat Containment Interior Shield Building Auxiliary Building Containment Air Baffle	C-I
Containment Vessel	C-I
Plant Vent and Stair Structure	C-II
Turbine Building	NS
Annex Building Columns A - D	NS
Annex Building Columns E - I	C-II
Radwaste Building	NS
Diesel-Generator Building	NS
Circulating Water Pumphouse and Towers	NS

C-I – Seismic Category I
C-II – Seismic Category II
NS – Non-seismic

Note:

1. Within the broad definition of seismic Category I and II structures, these buildings contain members and structural subsystems the failure of which would not impair the capability for safe shutdown. Examples of such systems would be elevators, stairwells not required for access in the event of a postulated earthquake, and nonstructural partitions in nonsafety-related areas. These substructures are classified as non-seismic.

Table 3.2-3 (Sheet 1 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Auxiliary Steam Supply System (ASS)					Location: Turbine Building
System components are Class E					
Steam Generator Blowdown System (BDS)					Location: Turbine Building
System components are Class E					
Compressed and Instrument Air System (CAS)					Location: Various
CAS-PL-V014	Instrument Air Supply Outside Containment Isolation	B	I	ASME III-2	
CAS-PL-V015	Instrument Air Supply Inside Containment Isolation	B	I	ASME III-2	
CAS-PL-V027	Containment Penetration Test Connection Isolation	B	I	ASME III-2	
CAS-PL-V204	Service Air Supply Outside Containment Isolation	B	I	ASME III-2	
CAS-PL-V205	Service Air Supply Inside Containment Isolation	B	I	ASME III-2	
CAS-PL-V219	Containment Penetration Test Connection Isolation	B	I	ASME III-2	
CAS-PY-C02	Containment Instrument Air Inlet Penetration	B	I	ASME III, MC	
CAS-PY-C03	Containment Service Air Inlet Penetration	B	I	ASME III, MC	
Balance of system components are Class E					
Component Cooling Water System (CCS)					Location: Auxiliary Building and Turbine Building
n/a	Heat Exchangers, CCS and SWS Side	D	NS	ASME VIII	
n/a	Pumps	D	NS	Hydraulic Institute Stds.	
n/a	Tanks	D	NS	ASME VIII	
n/a	Valves Providing CCS AP1000 Equipment Class D Function	D	NS	ANSI 16.34	
CCS-PL-V200	CCS Containment Isolation Valve - Inlet Line ORC	B	I	ASME III-2	
CCS-PL-V201	CCS Containment Isolation Valve - Inlet Line IRC	B	I	ASME III-2	

Table 3.2-3 (Sheet 2 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Component Cooling Water System (Continued)					
CCS-PL-V207	CCS Containment Isolation Valve - Outlet Line IRC	B	I	ASME III-2	
CCS-PL-V208	CCS Containment Isolation Valve - Outlet Line ORC	B	I	ASME III-2	
CCS-PL-V209	Containment Isolation Valve Test Connection - Outlet Line	B	I	ASME III-2	
CCS-PL-V257	Containment Isolation Valve Test Connection - Inlet Line	B	I	ASME III-2	
CCS-PY-C01	Containment Supply Header Penetration	B	I	ASME III, MC	
CCS-PY-C02	Containment Return Header Penetration	B	I	ASME III, MC	
Balance of system components are Class E					
Condensate System (CDS)					Location: Turbine Building
System components are Class E					
Condenser Tube Cleaning System (CES)					Location: Turbine Building
System components are Class E					
Turbine Island Chemical Feed System (CFS)					Location: Turbine Building
System components are Class E					
Condenser Air Removal System (CMS)					Location: Turbine Building
n/a	Condenser Vacuum Breakers	E	NS	ANSI 16.34	
Balance of system components are Class D					
Containment System (CNS)					Location: Containment
CNS-MV-01	Containment Vessel	B	I	ASME III, MC	
CNS-MY-Y01	Equipment Hatch	B	I	ASME III, MC	
CNS-MY-Y02	Maintenance Hatch	B	I	ASME III, MC	
CNS-MY-Y03	Personnel Hatch - 135′-3″	B	I	ASME III, MC	
CNS-MY-Y04	Personnel Hatch - 107′-2″	B	I	ASME III, MC	
n/a	Spare Containment Penetrations	B	I	ASME III, MC	
Condensate Polishing System (CPS)					Location: Turbine Building
System components are Class E					

Table 3.2-3 (Sheet 3 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Chemical and Volume Control System (CVS) Location: Containment, Auxiliary Building, and Annex Building					
n/a	Heat Exchangers, CVS and CCS Side	D	NS	ASME VIII/ TEMA	
n/a	Pumps	D	NS	Hydraulic Institute Stds.	
n/a	Tank	D	NS	API 650	
n/a	Demineralizers	D	NS	ASME VIII	
n/a	Filters	D	NS	ASME VIII	
n/a	Valves Providing CVS AP1000 Equipment Class D Function	D	NS	ANSI 16.34	
CVS-PL-V001	RCS Purification Stop	A	I	ASME III-1	
CVS-PL-V002	RCS Purification Stop	A	I	ASME III-1	
CVS-PL-V003	RCS Purification Stop	C	I	ASME III-3	
CVS-PL-V040	Resin Flush IRC Isolation	B	I	ASME III-2	
CVS-PL-V041	Resin Flush ORC Isolation	B	I	ASME III-2	
CVS-PL-V042	Flush Line Containment Isolation Relief	B	I	ASME III-2	
CVS-PL-V045	Letdown Containment Isolation IRC	B	I	ASME III-2	
CVS-PL-V046	Letdown Pressure Instrument Root	B	I	ASME III-2	
CVS-PL-V047	Letdown Containment Isolation ORC	B	I	ASME III-2	
CVS-PL-V080	RCS Purification Return Line Check Valve	C	I	ASME III-3	
CVS-PL-V081	RCS Purification Return Line Stop Valve	A	I	ASME III-1	
CVS-PL-V082	RCS Purification Return Line Check Valve	A	I	ASME III-1	
CVS-PL-V084	Auxiliary Pressurizer Spray Line Isolation	A	I	ASME III-1	
CVS-PL-V085	Auxiliary Pressurizer Spray Line	A	I	ASME III-1	
CVS-PL-V090	Makeup Line Containment Isolation	B	I	ASME III-2	
CVS-PL-V091	Makeup Line Containment Isolation	B	I	ASME III-2	

Table 3.2-4 (Sheet 4 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Chemical and Volume Control System (Continued)					
CVS-PL-V092	Hydrogen Add Containment Isolation	B	I	ASME III-2	
CVS-PL-V094	Hydrogen Add IRC Isolation	B	I	ASME III-2	
CVS-PL-V096	Hydrogen Add Containment Isolation Test Connection	B	I	ASME III-2	
CVS-PL-V100	Makeup Line Containment Isolation Relief	B	I	ASME III-2	
CVS-PL-V136A	Demineralized Water System Isolation	C	I	ASME III-3	
CVS-PL-V136B	Demineralized Water System Isolation	C	I	ASME III-3	
CVS-PY-C01	Demineralizer Resin Flush Line Containment Penetration	B	I	ASME III, MC	
CVS-PY-C02	Letdown Line Containment Penetration	B	I	ASME III, MC	
CVS-PY-C03	Makeup Line Containment Penetration	B	I	ASME III, MC	
CVS-PY-C04	Hydrogen Add Line Containment Penetration	B	I	ASME III, MC	
Balance of system components are Class D or E					
Circulating Water System (CWS) Location: Turbine Building and pump intake structure					
System components are Class E					
Standby Diesel and Auxiliary Boiler Fuel Oil System (DOS) Location: Diesel Generator Building and yard					
n/a	Fuel Oil Transfer Package	D	NS	Manufacturer Std.	
n/a	Fuel Oil Storage Tanks	D	NS	API 650	
n/a	Fuel Oil Day Tanks	D	NS	ASME VIII	
n/a	Valves Providing DOS AP1000 Equipment Class D Function	D	NS	ANSI 16.34	
n/a	Ancillary Diesel Generator Fuel Tank	D	II	UL 142	
Balance of system components are Class E					

Table 3.2-3 (Sheet 5 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Storm Drain System (DRS)					Location: Various
System components are Class E					
Demineralized Water Treatment System (DTS)					Location: Turbine Building
System components are Class E					
Demineralized Water Transfer and Storage System (DWS)					Location: Various
n/a	Condensate Storage Tanks	D	NS	API 650	
n/a	Valves Providing DWS AP1000 Equipment Class D Function	D	NS	ANSI 16.34	
DWS-PL-V244	Demineralized Water Supply Containment Isolation - Outside	B	I	ASME III-2	
DWS-PL-V245	Demineralized Water Supply Containment Isolation - Inside	B	I	ASME III-2	
DWS-PL-V248	Containment Penetration Test Connection Isolation	B	I	ASME III-2	
DWS-PY-C01	Containment Demineralized Water Supply Penetration	B	I	ASME III, MC	
Balance of system components are Class E					
Fuel Handling and Refueling System (FHS)					Location: Containment and Auxiliary Building
FHS-FH-02	Fuel Handling Machine	C	I	AISC	
FHS-FH-52	Spent Fuel Assembly Handling Tool	C	I	AISC	
FHS-FS-01	New Fuel Storage Rack	D	I	Manufacturer Std.	
FHS-FS-02	Spent Fuel Storage Rack	D	I	Manufacturer Std.	
FHS-FT-01	Fuel Transfer Tube	B	I	ASME III Class MC	
FHS-MT-01	Spent Fuel Pool	C	I	ACI 349	ACI 349 Evaluation of Structural Boundary Only
FHS-MT-02	Fuel Transfer Canal	C	I	ACI 349	ACI 349 Evaluation of Structural Boundary Only

Table 3.2-3 (Sheet 6 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Fuel Handling and Refueling System (Continued)					
FHS-MT-05	Spent Fuel Cask Loading Pit	C	I	ACI 349	ACI 349 Evaluation of Structural Boundary Only
FHS-MT-06	Spent Fuel Cask Washdown Pit	C	I	ACI 349	ACI 349 Evaluation of Structural Boundary Only
FHS-MY-Y01	Spent Fuel Transfer Gate	C	I	Manufacturer Std.	
FHS-MY-Y02	Spent Fuel Cask Loading Pit Gate	C	I	Manufacturer Std.	
FHS-PL-V001	Fuel transfer tube Isolation Valve	C	I	ASME-III-3	
FHS-PY-B01	Fuel Transfer Tube Blind Flange	B	I	ASME III-2	
Balance of system components are Class E					
Fire Protection System (FPS)					Location: Various
FPS-PL-V050	Fire Water Containment Supply Isolation	B	I	ASME III-2	
FPS-PL-V051	Fire Water Containment Test Connection Isolation	B	I	ASME III-2	
FPS-PL-V052	Fire Water Containment Supply Isolation - Inside	B	I	ASME III-2	
FPS-PY-C01	Fire Protection Containment Penetration	B	I	ASME III, MC	
Balance of system components are Class E					
Main and Startup Feedwater System (FWS)					Location: Turbine Building
n/a	Startup Feedwater Pumps	D	NS	Hydraulic Institute Standards	
n/a	Valves Providing SFW AP1000 Equipment Class D Function	D	NS	ANSI 16.34	
Balance of system components are Class E					

Table 3.2-3 (Sheet 7 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Gland Seal System (GSS)					Location: Turbine Building
System components are Class D					
Generator Hydrogen and CO_2 Systems (HCS)					Location: Turbine Building
System components are Class E					
Heater Drain System (HDS)					Location: Turbine Building
System components are Class E					
Hydrogen Seal Oil System (HSS)					Location: Turbine Building
System components are Class E					
Incore Instrumentation System (IIS)					Location: Containment
n/a	IIS Guide Tubes	A	I	ASME III-1	
n/a	Thimble assemblies	D	NS	Manufacturer Std.	
Main Turbine and Generator Lube Oil System (LOS)					Location: Turbine Building
System components are Class E					
Mechanical Handling System (MHS)					Location: Various
MHS-MH-01	Containment Polar Crane	C	I	ASME NOG-1	
MHS-MH-05	Equipment Hatch Hoist	C	I	Manufacturer Std.	
MHS-MH-06	Maintenance Hatch Hoist	D	I	Manufacturer Std.	
Balance of system components are Class E					
Main Steam System (MSS)					Location: Turbine Building
System components are Class E					
Main Turbine System (MTS)					Location: Turbine Building
System components are Class E					
Passive Containment Cooling System (PCS)					Location: Containment Shield Building and Auxiliary Building
PCS-MT-01	Passive Containment Cooling Water Storage Tank	C	I	ACI 349	See subsection 6.2.2.2.3 for additional design requirements
PCS-MT-03	Water Distribution Bucket	C	I	Manufacturer Std.	See subsection 6.2.2.2.3 for additional design requirements

Table 3.2-3 (Sheet 8 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Passive Containment Cooling System (Continued)					
PCS-MT-04	Water Collection Troughs	C	I	Manufacturer Std.	See subsection 6.2.2.2.3 for additional design requirements
PCS-MT-05	Passive Containment Cooling Ancillary Water Storage Tank	D	II	API 650	
PCS-PL-V001A	PCCWST Isolation	C	I	ASME III-3	
PCS-PL-V001B	PCCWST Isolation	C	I	ASME III-3	
PCS-PL-V001C	PCCWST Isolation	C	I	ASME III-3	
PCS-MP-01A	PCS Recirculation Pump	D	NS	Hydraulic Institute Standards	Equipment anchorage is Seismic Category II
PCS-MP-01B	PCS Recirculation Pump	D	NS	Hydraulic Institute Standards	Equipment anchorage is Seismic Category II
PCS-PL-V002A	PCCWST Series Isolation	C	I	ASME III-3	
PCS-PL-V002B	PCCWST Series Isolation	C	I	ASME III-3	
PCS-PL-V002C	PCCWST Series Isolation	C	I	ASME III-3	
PCS-PL-V005	PCCWST Supply to FPS Isolation	C	I	ASME III-3	
PCS-PL-V009	Spent Fuel Pool Emergency Makeup Isolation Valve	C	I	ASME III-3	
PCS-PL-V010A	Flow Transmitter FT001 Root Valve	C	I	ASME III-3	
PCS-PL-V010B	Flow Transmitter FT001 Root Valve	C	I	ASME III-3	
PCS-PL-V011A	Flow Transmitter FT002 Root Valve	C	I	ASME III-3	
PCS-PL-V011B	Flow Transmitter FT002 Root Valve	C	I	ASME III-3	
PCS-PL-V012A	Flow Transmitter FT003 Root Valve	C	I	ASME III-3	
PCS-PL-V012B	Flow Transmitter FT003 Root Valve	C	I	ASME III-3	

Table 3.2-3 (Sheet 9 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Passive Containment Cooling System (Continued)					
PCS-PL-V013A	Flow Transmitter FT004 Root Valve	C	I	ASME III-3	
PCS-PL-V013B	Flow Transmitter FT004 Root Valve	C	I	ASME III-3	
PCS-PL-V015	Water Bucket Makeup Line Drain Valve	C	I	ASME III	
PCS-PL-V016	PCCWST Drain Isolation Valve	C	I	ASME III-3	
PCS-PL-V017	Chemical Addition Tank Vent Isolation Valve	D	NS	ANSI 16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V018	Recirculation Pump Throttle Valve	D	NS	ANSI 16.34	Equipment anchorage is Seismic Category II
PCS-PL-V019	Chemical Addition Tank Fill Isolation Valve	D	NS	ANSI 16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V020	Water Bucket Makeup Line Isolation Valve	C	I	ASME III-3	
PCS-PL-V021	PCCWST TO Recirculation Pump Suction Isolation Valve	D	NS	ANSI 16.34	Equipment anchorage is Seismic Category II
PCS-PL-V022	Chemical Addition Tank Drain Isolation Valve	D	NS	ANSI 16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V023	PCS Recirculation Return Isolation	C	I	ASME III-3	
PCS-PL-V025	Pressure Transmitter PT 031 Root Isolation Valve	D	NS	ANSI 16.34	Equipment Anchorage is Seismic Category II

Table 3.2-3 (Sheet 10 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Passive Containment Cooling System (Continued)					
PCS-PL-V029	PCCWST Isolation Valve Leakage Detection Drain	C	I	ASME III-3	
PCS-PL-V030	PCCWST Isolation Valve Leakage Detection Crossconnect Valve	C	I	ASME III-3	
PCS-PL-V031A	Level Transmitter LT 016 & 010 Root Isolation Valve	C	I	ASME III-3	
PCS-PL-V031B	Level Transmitter LT 015 & 011 Root Isolation Valve	C	I	ASME III-3	
PCS-PL-V033	Recirculation Pump Suction from Long Term Makeup Isolation Valve	C	I	ASME III-3	
PCS-PL-V035A	Recirculation Pump Suction Isolation Valve	D	NS	ANSI 16.34	Equipment anchorage is Seismic Category II
PCS-PL-V035B	Recirculation Pump Suction Isolation Valve	D	NS	ANSI 16.34	Equipment anchorage is Seismic Category II
PCS-PL-V036A/B	Recirculation Pump Discharge Check Valve	D	NS	ANSI 16.34	Equipment anchorage is Seismic Category II
PCS-PL-V037	PCCAWST Discharge Isolation Valve	D	NS	ANSI 16.34	Equipment anchorage is Seismic Category II
PCS-PL-V038	PCCAWST Drain Isolation Valve	D	NS	ANSI 16.34	Equipment anchorage is Seismic Category II
PCS-PL-V039	PCCWST Long-Term Makeup Check Valve	C	I	ASME III-3	

Table 3.2-3 (Sheet 11 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Passive Containment Cooling System (Continued)					
PCS-PL-V040	Recirculation Pump Suction from PCCAWST Isolation Valve	D	NS	ANSI 16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V041	PCCAWST Recirculation Return Line Isolation Valve	D	NS	ANSI 16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V042	PCCWST Long-Term Makeup Isolation Drain Valve	C	I	ASME III-3	PCS-PL-V043
PCS-PL-V043	PCCAWST Recirculation Return Line Drain Isolation Valve	D	NS	ANSI 16.34	Equipment Anchorage is Seismic Category II
PCS-PL-V044	PCCWST Long-Term Makeup Isolation Valve	C	I	ASME III-3	
PCS-PL-V045	Emergency Makeup to the Spent Fuel Pool Isolation Valve	C	I	ASME III-3	
PCS-PL-V046	PCCWST Recirculation Return Isolation Valve	C	I	ASME III-3	
PCS-PL-V047	PCCWST Discharge Line Cross-Connect Isolation Valve	C	I	ASME III-3	
PCS-PL-V048	Recirculation Pump Fire Suction Isolation Valve	D	NS	ANSI 16.34	Seismically analyzed for operability
PCS-PL-V049	Emergency Makeup to the Spent Fuel Pool Drain Isolation Valve	C	I	ASME III-3	
PCS-PL-V050	Spent Fuel Pool Long Term Makeup Isolation Valve	C	I	ASME III-3	
PCS-PL-V051	Spent Fuel Pool Emergency Makeup Lower Isolation	C	I	ASME III-3	

Table 3.2-3 (Sheet 12 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Passive Containment Cooling System (Continued)					
PCS-PL-V100	Temporary Containment Washdown Isolation Valve	D	NS	ANSI 16.34	Equipment Anchorage is Seismic Category II
PCS-PY-B01	Spent Fuel Pool Emergency Makeup Isolation	C	I	ASME III-3	
Balance of system components are Class E					
Plant Gas Systems (PGS)					Location: Various
System components are Class E					
Primary Sampling System (PSS)					Location: Containment and Auxiliary Building
n/a	Grab Sample Unit	D	NS	Manufacturer Std.	
n/a	Sample Cooler, PSS and CCS Side	D	NS	ASME VIII/ TEMA	
n/a	Valves Providing PSS AP1000 Equipment Class D Function	D	NS	ANSI 16.34	
PSS-PL-V001A	Hot Leg Sample Isolation	B	I	ASME III-2	
PSS-PL-V001B	Hot Leg Sample Isolation	B	I	ASME III-2	
PSS-PL-V003	Pressurizer Liquid Isolation	B	I	ASME III-2	
PSS-PL-V004A	PXS Accumulator Sample Isolation	C	I	ASME III-3	
PSS-PL-V004B	PXS Accumulator Sample Isolation	C	I	ASME III-3	
PSS-PL-V005A	PXS CMT A Sample Isolation	B	I	ASME III-2	
PSS-PL-V005B	PXS CMT B Sample Isolation	B	I	ASME III-2	
PSS-PL-V005C	PXS CMT A Sample Isolation	B	I	ASME III-2	
PSS-PL-V005D	PXS CMT B Sample Isolation	B	I	ASME III-2	
PSS-PL-V008	Containment Air Sample Containment Isolation IRC	B	I	ASME III-2	
PSS-PL-V010A	Liquid Sample Line Containment Isolation IRC	B	I	ASME III-2	

Table 3.2-3 (Sheet 13 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Primary Sampling System (Continued)					
PSS-PL-V010B	Liquid Sample Line Containment Isolation IRC	B	I	ASME III-2	
PSS-PL-V011	Liquid Sample Line Containment Isolation ORC	B	I	ASME III-2	
PSS-PL-V012A	Liquid Sample Check Valve	C	I	ASME III-3	
PSS-PL-V012B	Liquid Sample Check Valve	C	I	ASME III-3	
PSS-PL-V023	Sample Return Line Containment Isolation ORC	B	I	ASME III-2	
PSS-PL-V024	Sample Return Containment Isolation Check IRC	B	I	ASME III-2	
PSS-PL-V046	Air Sample Line Containment Isolation ORC	B	I	ASME III-2	
PSS-PL-V076A	Containment Testing Boundary Isolation Valve	C	I	ASME III-3	
PSS-PL-V076B	Containment Testing Boundary Isolation Valve	C	I	ASME III-3	
PSS-PL-V082	Containment Isolation Test Connection Isolation Valve	C	I	ASME III-3	
PSS-PL-V083	Containment Isolation Test Connection Isolation Valve	C	I	ASME III-3	
PSS-PL-V085	Containment Isolation Test Connection Isolation Valve	B	I	ASME III-2	
PSS-PL-V086	Containment Isolation Test Connection Isolation Valve	C	I	ASME III-3	
PSS-PY-C01	Common Primary Sample Line Penetration	B	I	ASME III, MC	
PSS-PY-C02	Containment Atmosphere Sample Line Penetration	B	I	ASME III, MC	
PSS-PY-C03	Containment Atmosphere Sample Line Penetration	B	I	ASME III, MC	
Balance of system components are Class E					
Potable Water System (PWS)					Location: Various
System components are Class E					

Table 3.2-3 (Sheet 14 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Passive Core Cooling System (PXS)				Location: Containment	
PXS-ME-01	Passive Residual Heat Removal Heat Exchanger	A	I	ASME III-1	
PXS-MT-01A	Accumulator Tank A	C	I	ASME III-3	
PXS-MT-01B	Accumulator Tank B	C	I	ASME III-3	
PXS-MT-02A	Core Makeup Tank A	A	I	ASME III-1	
PXS-MT-02B	Core Makeup Tank B	A	I	ASME III-1	
PXS-MT-03	In-Containment Refueling Water Storage Tank	C	I	ACI 349/AISC N690	ACI 349 Is Used for Evaluation of Structural Boundary
PXS-MT-04	IRWST Gutter	C	I	Manufacturer Std.	
PXS-MW-01A	Reactor Coolant Depressurization Sparger A	C	I	ASME III-3	
PXS-MW-01B	Reactor Coolant Depressurization Sparger B	C	I	ASME III-3	
PXS-MY-Y01A	IRWST Screen A	C	I	Manufacturer Std.	
PXS-MY-Y01B	IRWST Screen B	C	I	Manufacturer Std.	
PXS-MY-Y02A	Containment Recirculation Screen A	C	I	Manufacturer Std.	
PXS-MY-Y02B	Containment Recirculation Screen B	C	I	Manufacturer Std.	
PXS-MY-Y03A	pH Adjustment Basket A	C	I	Manufacturer Std.	
PXS-MY-Y03B	pH Adjustment Basket B	C	I	Manufacturer Std.	
PXS-MY-Y03C	pH Adjustment Basket C	C	I	Manufacturer Std.	
PXS-MY-Y03D	pH Adjustment Basket D	C	I	Manufacturer Std.	
PXS-PL-V002A	CMT A CL Inlet Isolation	A	I	ASME III-1	
PXS-PL-V002B	CMT B CL Inlet Isolation	A	I	ASME III-1	
PXS-PL-V010A	CMT A Upper Sample	B	I	ASME III-2	
PXS-PL-V010B	CMT B Upper Sample	B	I	ASME III-2	
PXS-PL-V011A	CMT A Lower Sample	B	I	ASME III-2	

Table 3.2-3 (Sheet 15 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Passive Core Cooling System (Continued)					
PXS-PL-V011B	CMT B Lower Sample	B	I	ASME III-2	
PXS-PL-V012A	CMT A Drain	A	I	ASME III-1	
PXS-PL-V012B	CMT B Drain	A	I	ASME III-1	
PXS-PL-V013A	CMT A Discharge Manual Isolation	A	I	ASME III-1	
PXS-PL-V013B	CMT B Discharge Manual Isolation	A	I	ASME III-1	
PXS-PL-V014A	CMT A Discharge Isolation	A	I	ASME III-1	
PXS-PL-V014B	CMT B Discharge Isolation	A	I	ASME III-1	
PXS-PL-V015A	CMT A Discharge Isolation	A	I	ASME III-1	
PXS-PL-V015B	CMT B Discharge Isolation	A	I	ASME III-1	
PXS-PL-V016A	CMT A Discharge Check	A	I	ASME III-1	
PXS-PL-V016B	CMT B Discharge Check	A	I	ASME III-1	
PXS-PL-V017A	CMT A Discharge Check	A	I	ASME III-1	
PXS-PL-V017B	CMT B Discharge Check	A	I	ASME III-1	
PXS-PL-V021A	Accumulator A Nitrogen Vent	C	I	ASME III-3	
PXS-PL-V021B	Accumulator B Nitrogen Vent	C	I	ASME III-3	
PXS-PL-V022A	Accumulator A Pressure Relief	C	I	ASME III-3	
PXS-PL-V022B	Accumulator B Pressure Relief	C	I	ASME III-3	
PXS-PL-V023A	Accumulator A Pressure Transmitter B Isolation	C	I	ASME III-3	
PXS-PL-V023B	Accumulator B Pressure Transmitter B Isolation	C	I	ASME III-3	
PXS-PL-V024A	Accumulator A Pressure Transmitter A Isolation	C	I	ASME III-3	
PXS-PL-V024B	Accumulator B Pressure Transmitter A Isolation	C	I	ASME III-3	
PXS-PL-V025A	Accumulator A Sample	C	I	ASME III-3	
PXS-PL-V025B	Accumulator B Sample	C	I	ASME III-3	
PXS-PL-V026A	Accumulator A Drain	C	I	ASME III-3	
PXS-PL-V026B	Accumulator B Drain	C	I	ASME III-3	

Table 3.2-3 (Sheet 16 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Passive Core Cooling System (Continued)					
PXS-PL-V027A	Accumulator A Discharge Isolation	C	I	ASME III-3	
PXS-PL-V027B	Accumulator B Discharge Isolation	C	I	ASME III-3	
PXS-PL-V028A	Accumulator A Discharge Check	A	I	ASME III-1	
PXS-PL-V028B	Accumulator B Discharge Check	A	I	ASME III-1	
PXS-PL-V029A	Accumulator A Discharge Check	A	I	ASME III-1	
PXS-PL-V029B	Accumulator B Discharge Check	A	I	ASME III-1	
PXS-PL-V030A	CMT A Highpoint Vent	B	I	ASME III-2	
PXS-PL-V030B	CMT B Highpoint Vent	B	I	ASME III-2	
PXS-PL-V031A	CMT A Highpoint Vent	B	I	ASME III-2	
PXS-PL-V031B	CMT B Highpoint Vent	B	I	ASME III-2	
PXS-PL-V033A	Accumulator A Check Valve Drain	B	I	ASME III-2	
PXS-PL-V033B	Accumulator B Check Valve Drain	B	I	ASME III-2	
PXS-PL-V042	Nitrogen Supply Containment Isolation ORC	B	I	ASME III-2	
PXS-PL-V043	Nitrogen Supply Containment Isolation IRC	B	I	ASME III-2	
PXS-PL-V052	Accumulator Nitrogen Containment Penetration TC	B	I	ASME III-2	
PXS-PL-V080A	CMT A WR Level Isolation	B	I	ASME III-2	
PXS-PL-V080B	CMT B WR Level Isolation	B	I	ASME III-2	
PXS-PL-V081A	CMT A WR Level Isolation	B	I	ASME III-2	
PXS-PL-V081B	CMT B WR Level Isolation	B	I	ASME III-2	
PXS-PL-V085A	CMT A NR Upper Level Isolation	B	I	ASME III-2	
PXS-PL-V085B	CMT B NR Upper Level Isolation	B	I	ASME III-2	

Table 3.2-3 (Sheet 17 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Passive Core Cooling System (Continued)					
PXS-PL-V086A	CMT A NR Upper Level Isolation	B	I	ASME III-2	
PXS-PL-V086B	CMT B NR Upper Level Isolation	B	I	ASME III-2	
PXS-PL-V087A	CMT A NR Lower Level Isolation	B	I	ASME III-2	
PXS-PL-V087B	CMT B NR Lower Level Isolation	B	I	ASME III-2	
PXS-PL-V088A	CMT A NR Lower Level Isolation	B	I	ASME III-2	
PXS-PL-V088B	CMT B NR Lower Level Isolation	B	I	ASME III-2	
PXS-PL-V101	PRHR HX Inlet Isolation	A	I	ASME III-1	
PXS-PL-V102A	PRHR HX Inlet Head Vent	B	I	ASME III-2	
PXS-PL-V102B	PRHR HX Inlet Head Drain	B	I	ASME III-2	
PXS-PL-V103A	PRHR HX Outlet Head Vent	B	I	ASME III-2	
PXS-PL-V103B	PRHR HX Outlet Head Drain	B	I	ASME III-2	
PXS-PL-V104A	PRHR HX Flow Transmitter A Isolation	B	I	ASME III-2	
PXS-PL-V104B	PRHR HX Flow Transmitter B Isolation	B	I	ASME III-2	
PXS-PL-V105A	PRHR HX Flow Transmitter A Isolation	B	I	ASME III-2	
PXS-PL-V105B	PRHR HX Flow Transmitter B Isolation	B	I	ASME III-2	
PXS-PL-V108A	PRHR HX Control	A	I	ASME III-1	
PXS-PL-V108B	PRHR HX Control	A	I	ASME III-1	
PXS-PL-V109	PRHR HX/RCS Return Isolation	A	I	ASME III-1	
PXS-PL-V111A	PRHR HX Highpoint Vent	B	I	ASME III-2	
PXS-PL-V111B	PRHR HX Highpoint Vent	B	I	ASME III-2	
PXS-PL-V113	PRHR HX Pressure Transmitter Isolation	B	I	ASME III-2	

Table 3.2-3 (Sheet 18 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Passive Core Cooling System (Continued)					
PXS-PL-V117A	Containment Recirculation A Isolation	C	I	ASME III-3	
PXS-PL-V117B	Containment Recirculation B Isolation	C	I	ASME III-3	
PXS-PL-V118A	Containment Recirculation A Isolation	C	I	ASME III-3	
PXS-PL-V118B	Containment Recirculation B Isolation	C	I	ASME III-3	
PXS-PL-V119A	Containment Recirculation A Check	C	I	ASME III-3	
PXS-PL-V119B	Containment Recirculation B Check	C	I	ASME III-3	
PXS-PL-V120A	Containment Recirculation A Isolation	C	I	ASME III-3	
PXS-PL-V120B	Containment Recirculation B Isolation	C	I	ASME III-3	
PXS-PL-V121A	IRWST Line A Isolation	C	I	ASME III-3	
PXS-PL-V121B	IRWST Line B Isolation	C	I	ASME III-3	
PXS-PL-V122A	IRWST Injection A Check	A	I	ASME III-1	
PXS-PL-V122B	IRWST Injection B Check	A	I	ASME III-1	
PXS-PL-V123A	IRWST Injection A Isolation	A	I	ASME III-1	
PXS-PL-V123B	IRWST Injection B Isolation	A	I	ASME III-1	
PXS-PL-V124A	IRWST Injection A Check	A	I	ASME III-1	
PXS-PL-V124B	IRWST Injection B Check	A	I	ASME III-1	
PXS-PL-V125A	IRWST Injection A Isolation	A	I	ASME III-1	
PXS-PL-V125B	IRWST Injection B Isolation	A	I	ASME III-1	
PXS-PL-V126A	IRWST Injection Check Test	C	I	ASME III-3	
PXS-PL-V126B	IRWST Injection Check Test	C	I	ASME III-3	
PXS-PL-V127	IRWST to Containment Sump	C	I	ASME III-3	
PXS-PL-V128A	IRWST Injection Check Test	B	I	ASME III-2	
PXS-PL-V128B	IRWST Injection Check Test	B	I	ASME III-2	
PXS-PL-V129A	IRWST Injection Check Test	B	I	ASME III-2	
PXS-PL-V129B	IRWST Injection Check Test	B	I	ASME III-2	

Table 3.2-3 (Sheet 19 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Passive Core Cooling System (Continued)					
PXS-PL-V130A	IRWST Gutter Bypass A Isolation	C	I	ASME III-3	
PXS-PL-V130B	IRWST Gutter Bypass B Isolation	C	I	ASME III-3	
PXS-PL-V150A	IRWST Level Transmitter A Isolation	C	I	ASME III-3	
PXS-PL-V150B	IRWST Level Transmitter B Isolation	C	I	ASME III-3	
PXS-PL-V150C	IRWST Level Transmitter C Isolation	C	I	ASME III-3	
PXS-PL-V150D	IRWST Level Transmitter D Isolation	C	I	ASME III-3	
PXS-PL-V151A	IRWST Level Transmitter A Isolation	C	I	ASME III-3	
PXS-PL-V151B	IRWST Level Transmitter B Isolation	C	I	ASME III-3	
PXS-PL-V151C	IRWST Level Transmitter C Isolation	C	I	ASME III-3	
PXS-PL-V151D	IRWST Level Transmitter D Isolation	C	I	ASME III-3	
PXS-PL-V201A	Accumulator A Leak Test	B	I	ASME III-2	
PXS-PL-V201B	Accumulator B Leak Test	B	I	ASME III-2	
PXS-PL-V202A	Accumulator A Leak Test	C	I	ASME III-3	
PXS-PL-V202B	Accumulator B Leak Test	C	I	ASME III-3	
PXS-PL-V205A	RNS Discharge Leak Test	B	I	ASME III-2	
PXS-PL-V205B	RNS Discharge Leak Test	B	I	ASME III-2	
PXS-PL-V206	RNS Discharge Leak Test	C	I	ASME III-3	
PXS-PL-V207A	RNS Suction Leak Test	B	I	ASME III-2	
PXS-PL-V207B	RNS Suction Leak Test	B	I	ASME III-2	
PXS-PL-V208A	RNS Suction Leak Test	B	I	ASME III-2	
PXS-PL-V217	PXS Leak Test Line Isolation	D	NS	ANSI B31.1	
PXS-PL-V221	Test Header to IRWST	D	NS	ANSI B31.1	
PXS-PL-V230A	CMT A Fill Isolation	B	I	ASME III-2	
PXS-PL-V230B	CMT B Fill Isolation	B	I	ASME III-2	

Table 3.2-3 (Sheet 20 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Passive Core Cooling System (Continued)					
PXS-PL-V231A	CMT A Fill Check	B	I	ASME III-2	
PXS-PL-V231B	CMT B Fill Check	B	I	ASME III-2	
PXS-PL-V232A	Accumulator A Fill/Drain Isolation	C	I	ASME III-3	
PXS-PL-V232B	Accumulator B Fill/Drain Isolation	C	I	ASME III-3	
PXS-PY-C01	Nitrogen Makeup Containment Penetration	B	I	ASME III, MC	
Balance of system components are Class E					
Reactor Coolant System (RCS)					Location: Containment
RCS-MB-01	Steam Generator 1	A	I	ASME III-1	
RCS-MB-02	Steam Generator 2	A	I	ASME III-1	
RCS-MP-01A	SG 1 Normal Rotation Reactor Coolant Pump	A	I	ASME III-1	
RCS-MP-01B	SG 1 Reverse Rotation Reactor Coolant Pump	A	I	ASME III-1	
RCS-MP-02A	SG 2 Normal Rotation Reactor Coolant Pump	A	I	ASME III-1	
RCS-MP-02B	SG 2 Reverse Rotation Reactor Coolant Pump	A	I	ASME III-1	
RCS-MV-01	Reactor Vessel	A	I	ASME III-1	
RCS-MV-02	Pressurizer	A	I	ASME III-1	
RCS-MY-Y11	SG 1 Shell	B	I	ASME III-1	
RCS-MY-Y12	SG 1 Channel Head Divider Plate	B	I	ASME III-1	
RCS-MY-Y13	SG 1 Tube Bundle Support Assembly	C	I	ASME III, NG	
RCS-MY-Y14	SG 1 Steam Flow Limiting Venturi	B	I	ASME III, NG	
RCS-MY-Y15	SG 1 Feedwater Distribution Ring Supports	B	I	ASME III, NG	
RCS-MY-Y21	SG 2 Shell	B	I	ASME III-1	
RCS-MY-Y22	SG 2 Channel Head Divider Plate	B	I	ASME III-1	

Table 3.2-3 (Sheet 21 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor Coolant System (Continued)					
RCS-MY-Y23	SG 2 Tube Bundle Support Assembly	C	I	ASME III, NG	
RCS-MY-Y24	SG 2 Steam Flow Limiting Venturi	B	I	ASME III, NG	
RCS-MY-Y25	SG 2 Feedwater Distribution Ring Supports	B	I	ASME III, NG	
RCS-PL-V001A	First Stage ADS	A	I	ASME III-1	
RCS-PL-V001B	First Stage ADS	A	I	ASME III-1	
RCS-PL-V002A	Second Stage ADS	A	I	ASME III-1	
RCS-PL-V002B	Second Stage ADS	A	I	ASME III-1	
RCS-PL-V003A	Third Stage ADS	A	I	ASME III-1	
RCS-PL-V003B	Third Stage ADS	A	I	ASME III-1	
RCS-PL-V004A	Fourth Stage ADS	A	I	ASME III-1	
RCS-PL-V004B	Fourth Stage ADS	A	I	ASME III-1	
RCS-PL-V004C	Fourth Stage ADS	A	I	ASME III-1	
RCS-PL-V004D	Fourth Stage ADS	A	I	ASME III-1	
RCS-PL-V005A	Pressurizer Safety Valve	A	I	ASME III-1	
RCS-PL-V005B	Pressurizer Safety Valve	A	I	ASME III-1	
RCS-PL-V007A	ADS Test Valve	B	I	ASME III-2	
RCS-PL-V007B	ADS Test Valve	B	I	ASME III-2	
RCS-PL-V010A	ADS Discharge Header A Vacuum Relief	C	I	ASME III-3	
RCS-PL-V010B	ADS Discharge Header B Vacuum Relief	C	I	ASME III-3	
RCS-PL-V011A	First Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V011B	First Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V012A	Second Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V012B	Second Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V013A	Third Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V013B	Third Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V014A	Fourth Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V014B	Fourth Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V014C	Fourth Stage ADS Isolation	A	I	ASME III-1	

Table 3.2-3 (Sheet 22 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor Coolant System (Continued)					
RCS-PL-V014D	Fourth Stage ADS Isolation	A	I	ASME III-1	
RCS-PL-V095	Hot Leg 2 Level Instrument Root	B	I	ASME III-2	
RCS-PL-V096	Hot Leg 2 Level Instrument Root	B	I	ASME III-2	ADS Test Valve
RCS-PL-V097	Hot Leg 1 Level Instrument Root	B	I	ASME III-2	
RCS-PL-V098	Hot Leg 1 Level Instrument Root	B	I	ASME III-2	
RCS-PL-V101A	Hot Leg 1 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V101B	Hot Leg 1 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V101C	Hot Leg 1 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V101D	Hot Leg 1 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V101E	Hot Leg 1 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V101F	Hot Leg 1 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V102A	Hot Leg 2 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V102B	Hot Leg 2 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V102C	Hot Leg 2 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V102D	Hot Leg 2 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V102E	Hot Leg 2 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V102F	Hot Leg 2 Flow Instrument Root	B	I	ASME III-2	
RCS-PL-V171A	Cold Leg 1A Bend Instrument Root	B	I	ASME III-2	

Table 3.2-3 (Sheet 23 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor Coolant System (Continued)					
RCS-PL-V171B	Cold Leg 1A Bend Instrument Root	B	I	ASME III-2	
RCS-PL-V172A	Cold Leg 1B Bend Instrument Root	B	I	ASME III-2	
RCS-PL-V172B	Cold Leg 1B Bend Instrument Root	B	I	ASME III-2	
RCS-PL-V173A	Cold Leg 2A Bend Instrument Root	B	I	ASME III-2	
RCS-PL-V173B	Cold Leg 2A Bend Instrument Root	B	I	ASME III-2	
RCS-PL-V174A	Cold Leg 2B Bend Instrument Root	B	I	ASME III-2	
RCS-PL-V174B	Cold Leg 2B Bend Instrument Root	B	I	ASME III-2	
RCS-PL-V108A	Hot Leg 1 Sample Isolation	B	I	ASME III-2	
RCS-PL-V108B	Hot Leg 2 Sample Isolation	B	I	ASME III-2	
RCS-PL-V110A	Pressurizer Spray Valve	A	I	ASME III-1	
RCS-PL-V110B	Pressurizer Spray Valve	A	I	ASME III-1	
RCS-PL-V111A	Pressurizer Spray Block Valve	A	I	ASME III-1	
RCS-PL-V111B	Pressurizer Spray Block Valve	A	I	ASME III-1	
RCS-PL-V120	Reactor Vessel Flange Leakoff	D	NS	ANSI B31.1	
RCS-PL-V121	Reactor Vessel Flange Leakoff	D	NS	ANSI B31.1	
RCS-PL-V122A	Reactor Vessel Flange Leakoff	D	NS	ANSI B31.1	
RCS-PL-V122B	Reactor Vessel Flange Leakoff	D	NS	ANSI B31.1	
RCS-PL-V150A	Reactor Vessel Head Vent	A	I	ASME III-1	
RCS-PL-V150B	Reactor Vessel Head Vent	A	I	ASME III-1	
RCS-PL-V150C	Reactor Vessel Head Vent	A	I	ASME III-1	
RCS-PL-V150D	Reactor Vessel Head Vent	A	I	ASME III-1	

Table 3.2-3 (Sheet 24 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor Coolant System (Continued)					
RCS-PL-V203	Pressurizer Steam Space Sample Isolation	B	I	ASME III-2	
RCS-PL-V204	Pressurizer Manual Vent	A	I	ASME III-1	
RCS-PL-V205	Pressurizer Manual Vent	A	I	ASME III-1	
RCS-PL-V210A	Pressurizer Spray Bypass	B	I	ASME III-2	
RCS-PL-V210B	Pressurizer Spray Bypass	B	I	ASME III-2	
RCS-PL-V225A	Pressurizer Level Steam Space Instrument Root	B	I	ASME III-2	
RCS-PL-V225B	Pressurizer Level Steam Space Instrument Root	B	I	ASME III-2	
RCS-PL-V225C	Pressurizer Level Steam Space Instrument Root	B	I	ASME III-2	
RCS-PL-V225D	Pressurizer Level Steam Space Instrument Root	B	I	ASME III-2	
RCS-PL-V226A	Pressurizer Level Liquid Space Instrument Root	B	I	ASME III-2	
RCS-PL-V226B	Pressurizer Level Liquid Space Instrument Root	B	I	ASME III-2	
RCS-PL-V226C	Pressurizer Level Liquid Space Instrument Root	B	I	ASME III-2	
RCS-PL-V226D	Pressurizer Level Liquid Space Instrument Root	B	I	ASME III-2	
RCS-PL-V228	Wide Range Pressurizer Level Steam Space Instrument Root	B	I	ASME III-2	
RCS-PL-V229	Wide Range Pressurizer Level Liquid Space Instrument Root	B	I	ASME III-2	
RCS-PL-V232	Manual Head Vent	C	I	ASME III-3	
RCS-PL-V233	Head Vent Isolation	C	I	ASME III-3	
RCS-PL-V241	ADS Valve Discharge Header Drain Isolation	C	I	ASME III-3	
RCS-PL-V242	ADS Valve Discharge Header Drain Check	D	NS	ANSI 16.34	

Table 3.2-3 (Sheet 25 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor Coolant System (Continued)					
RCS-PL-V255A	RCP 1A Flange Leakoff	D	NS	ANSI 16.34	
RCS-PL-V255B	RCP 1B Flange Leakoff	D	NS	ANSI 16.34	
RCS-PL-V255C	RCP 2A Flange Leakoff	D	NS	ANSI 16.34	
RCS-PL-V255D	RCP 2B Flange Leakoff	D	NS	ANSI 16.34	
RCS-PL-V256A	RCP 1A Flange Leakoff	D	NS	ANSI 16.34	
RCS-PL-V256B	RCP 1B Flange Leakoff	D	NS	ANSI 16.34	
RCS-PL-V256C	RCP 2A Flange Leakoff	D	NS	ANSI 16.34	
RCS-PL-V256D	RCP 2B Flange Leakoff	D	NS	ANSI 16.34	
RCS-PL-V260A	RCP 1A Flush	A	I	ASME III-1	
RCS-PL-V260B	RCP 1B Flush	A	I	ASME III-1	
RCS-PL-V260C	RCP 2A Flush	A	I	ASME III-1	
RCS-PL-V260D	RCP 2B Flush	A	I	ASME III-1	
RCS-PL-V261A	RCP 1A Drain	A	I	ASME III-1	
RCS-PL-V261B	RCP 1B Drain	A	I	ASME III-1	
RCS-PL-V261C	RCP 2A Drain	A	I	ASME III-1	
RCS-PL-V261D	RCP 2B Drain	A	I	ASME III-1	
RCS-PY-K03	Safety Valve Discharge Chamber Rupture Disk	C	I	ASME III-3	
RCS-PY-K04	Safety Valve Discharge Chamber Rupture Disk	C	I	ASME III-3	
Gravity and Roof Drain Collection System (RDS)					Location: Various
System components are Class E					
Normal Residual Heat Removal System (RNS)					Location: Containment and Auxiliary Building
RNS-ME-01A	Normal Residual Heat Removal Heat Exchanger A (Tube Side)	C	I	ASME III-3	Shellside - Class D ASME VIII, Div. 1
RNS-ME-01B	Normal Residual Heat Removal Heat Exchanger B (Tube Side)	C	I	ASME III-3	Shellside - Class D ASME VIII, Div. 1
RNS-MP-01A	Residual Heat Removal Pump A	C	I	ASME III-3	Pump Motor - Class D
RNS-MP-01B	Residual Heat Removal Pump B	C	I	ASME III-3	Pump Motor - Class D

Table 3.2-3 (Sheet 26 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Normal Residual Heat Removal System (Continued)					
RNS-PL-V001A	RNS HL Suction Isolation - Inner	A	I	ASME III-1	
RNS-PL-V001B	RNS HL Suction Isolation - Inner	A	I	ASME III-1	
RNS-PL-V002A	RNS HL Suction and Containment Isolation - Outer	A	I	ASME III-1	
RNS-PL-V002B	RNS HL Suction and Containment Isolation - Outer	A	I	ASME III-1	
RNS-PL-V003A	RCS Pressure Boundary Valve Thermal Relief	B	I	ASME III-2	
RNS-PL-V003B	RCS Pressure Boundary Valve Thermal Relief	B	I	ASME III-2	
RNS-PL-V004A	RCS Pressure Boundary Valve Thermal Relief Isolation	B	I	ASME III-2	
RNS-PL-V004B	RCS Pressure Boundary Valve Thermal Relief Isolation	B	I	ASME III-2	
RNS-PL-V005A	RNS Pump A Suction Isolation	C	I	ASME III-3	
RNS-PL-V005B	RNS Pump B Suction Isolation	C	I	ASME III-3	
RNS-PL-V006A	RNS HX A Outlet Flow Control	C	I	ASME III-3	
RNS-PL-V006B	RNS HX B Outlet Flow Control	C	I	ASME III-3	
RNS-PL-V007A	RNS Pump A Discharge Isolation	C	I	ASME III-3	
RNS-PL-V007B	RNS Pump B Discharge Isolation	C	I	ASME III-3	
RNS-PL-V008A	RNS HX A Bypass Flow Control	C	I	ASME III-3	
RNS-PL-V008B	RNS HX B Bypass Flow Control	C	I	ASME III-3	
RNS-PL-V010	RNS Discharge Containment Isolation Valve Test	C	I	ASME III-3	

Table 3.2-3 (Sheet 27 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Normal Residual Heat Removal System (Continued)					
RNS-PL-V011	RNS Discharge Containment Isolation Valve - ORC	B	I	ASME III-2	
RNS-PL-V012	RNS Discharge Containment Isolation Valve Test Connection ORC	B	I	ASME III-2	
RNS-PL-V013	RNS Discharge Containment Isolation - IRC	B	I	ASME III-2	
RNS-PL-V014	RNS Discharge Containment Isolation Valve Test Connection	C	I	ASME III-3	
RNS-PL-V015A	RNS Discharge RCS Pressure Boundary	A	I	ASME III-1	
RNS-PL-V015B	RNS Discharge RCS Pressure Boundary	A	I	ASME III-1	
RNS-PL-V016	RNS Discharge Containment Penetration Isolation Valves Test	C	I	ASME III-3	
RNS-PL-V017A	RNS Discharge RCS Pressure Boundary	A	I	ASME III-1	
RNS-PL-V017B	RNS Discharge RCS Pressure Boundary	A	I	ASME III-1	
RNS-PL-V021	RNS HL Suction Pressure Relief	B	I	ASME III-2	
RNS-PL-V022	RNS Suction Header Containment Isolation - ORC	B	I	ASME III-2	
RNS-PL-V023	RNS Suction from IRWST - Containment Isolation	B	I	ASME III-2	
RNS-PL-V024	RNS Discharge to IRWST Isolation	C	I	ASME III-3	
RNS-PL-V025A	RNS HX A Bypass Flow Instrument Isolation	C	I	ASME III-3	
RNS-PL-V025B	RNS HX B Bypass Flow Instrument Isolation	C	I	ASME III-3	
RNS-PL-V026A	RNS HX A Bypass Flow Instrument Isolation	C	I	ASME III-3	

Table 3.2-3 (Sheet 28 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Normal Residual Heat Removal System (Continued)					
RNS-PL-V026B	RNS HX B Bypass Flow Instrument Isolation	C	I	ASME III-3	
RNS-PL-V029	RNS Discharge to CVS	C	I	ASME III-3	
RNS-PL-V030A	RNS HX A Shell Drain	D	NS	ANSI B31.1	
RNS-PL-V030B	RNS HX B Shell Drain	D	NS	ANSI B31.1	
RNS-PL-V031A	RNS Train A Discharge Flow Instrument Isolation	C	I	ASME III-3	
RNS-PL-V031B	RNS Train B Discharge Flow Instrument Isolation	C	I	ASME III-3	
RNS-PL-V032A	RNS Train A Discharge Flow Instrument Isolation	C	I	ASME III-3	
RNS-PL-V032B	RNS Train B Discharge Flow Instrument Isolation	C	I	ASME III-3	
RNS-PL-V033A	RNS Pump A Suction Pressure Instrument Isolation	C	I	ASME III-3	
RNS-PL-V033B	RNS Pump B Suction Pressure Instrument Isolation	C	I	ASME III-3	
RNS-PL-V034A	RNS Pump A Discharge Pressure Instrument Isolation	C	I	ASME III-3	
RNS-PL-V034B	RNS Pump B Discharge Pressure Instrument Isolation	C	I	ASME III-3	
RNS-PL-V035A	RNS HX A Shell Vent	D	NS	ANSI 16.34	
RNS-PL-V035B	RNS HX B Shell Vent	D	NS	ANSI 16.34	
RNS-PL-V036A	RNS Pump A Suction Piping Drain. Isolation	C	I	ASME III-3	
RNS-PL-V036B	RNS Pump B Suction Piping Drain. Isolation	C	I	ASME III-3	
RNS-PL-V045	RNS Pump Discharge Relief	C	I	ASME III-3	
RNS-PL-V046	RNS HX A Channel Head Drain. Isolation	C	I	ASME III-3	
RNS-PL-V048	RNS HX B Channel Head Drain. Isolation	C	I	ASME III-3	
RNS-PL-V050	RNS Pump A Casing Drain. Isolation	C	I	ASME III-3	

Table 3.2-3 (Sheet 29 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Normal Residual Heat Removal System (Continued)					
RNS-PL-V051	RNS Pump B Casing Drain. Isolation	C	I	ASME III-3	
RNS-PL-V052	RNS Pump Suction From Spent Fuel Pool Isolation	C	I	ASME III-3	
RNS-PL-V053	RNS Pump Discharge to Spent Fuel Pool Isolation	C	I	ASME III-3	
RNS-PL-V055	RNS Pump Suction to Cask Loading Pit Isolation	C	I	ASME III-3	
RNS-PL-V056	RNS Pump Suction to Cask Loading Pit Isolation	C	I	ASME III-3	
RNS-PL-V057A	RNS Pump A Miniflow Isolation	C	I	ASME III-3	
RNS-PL-V057B	RNS Pump B Miniflow Isolation	C	I	ASME III-3	
RNS-PL-V059	RNS Pump Suction Containment Isolation Test Connection	C	I	ASME III-3	
RNS-PL-V061	RNS Return from CVS - Containment Isolation	B	I	ASME III-2	
RNS-PY-C01	Normal Residual Heat Removal Suction Line Penetration	B	I	ASME III, MC	
RNS-PY-C02	Normal Residual Heat Removal Discharge Line Penetration	B	I	ASME III, MC	
Balance of system components are Class E					
Raw Water System (RWS)					Location: Yard, Turbine Building
System components are Class E					
Reactor System (RXS)					Location: Containment
n/a	Fuel Assemblies	C	I	Manufacturer Std.	
RXS-FR-B06	Control Rod Cluster B6	B	I	Manufacturer Std.	
RXS-FR-B10	Control Rod Cluster B10	B	I	Manufacturer Std.	

Table 3.2-3 (Sheet 30 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-FR-C05	Control Rod Cluster C5	B	I	Manufacturer Std.	
RXS-FR-C07	Control Rod Cluster C7	B	I	Manufacturer Std.	
RXS-FR-C09	Control Rod Cluster C9	B	I	Manufacturer Std.	
RXS-FR-C11	Control Rod Cluster C11	B	I	Manufacturer Std.	
RXS-FR-D06	Control Rod Cluster D6	B	I	Manufacturer Std.	
RXS-FR-D08	Control Rod Cluster D8	B	I	Manufacturer Std.	
RXS-FR-D10	Control Rod Cluster D10	B	I	Manufacturer Std.	
RXS-FR-E03	Control Rod Cluster E3	B	I	Manufacturer Std.	
RXS-FR-E05	Control Rod Cluster E5	B	I	Manufacturer Std.	
RXS-FR-E07	Control Rod Cluster E7	B	I	Manufacturer Std.	
RXS-FR-E09	Control Rod Cluster E9	B	I	Manufacturer Std.	
RXS-FR-E11	Control Rod Cluster E11	B	I	Manufacturer Std.	
RXS-FR-E13	Control Rod Cluster E13	B	I	Manufacturer Std.	
RXS-FR-F02	Control Rod Cluster F2	B	I	Manufacturer Std.	
RXS-FR-F04	Control Rod Cluster F4	B	I	Manufacturer Std.	
RXS-FR-F12	Control Rod Cluster F12	B	I	Manufacturer Std.	
RXS-FR-F14	Control Rod Cluster F14	B	I	Manufacturer Std	
RXS-FR-G03	Control Rod Cluster G3	B	I	Manufacturer Std.	

Table 3.2-3 (Sheet 31 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-FR-G05	Control Rod Cluster G5	B	I	Manufacturer Std.	
RXS-FR-G07	Control Rod Cluster G7	B	I	Manufacturer Std.	
RXS-FR-G09	Control Rod Cluster G9	B	I	Manufacturer Std.	
RXS-FR-G11	Control Rod Cluster G11	B	I	Manufacturer Std.	
RXS-FR-G13	Control Rod Cluster G13	B	I	Manufacturer Std.	
RXS-FR-H04	Control Rod Cluster H4	B	I	Manufacturer Std.	
RXS-FR-H08	Control Rod Cluster H8	B	I	Manufacturer Std.	
RXS-FR-H12	Control Rod Cluster H12	B	I	Manufacturer Std.	
RXS-FR-J03	Control Rod Cluster J3	B	I	Manufacturer Std.	
RXS-FR-J05	Control Rod Cluster J5	B	I	Manufacturer Std.	
RXS-FR-J07	Control Rod Cluster J7	B	I	Manufacturer Std.	
RXS-FR-J09	Control Rod Cluster J9	B	I	Manufacturer Std.	
RXS-FR-J11	Control Rod Cluster J11	B	I	Manufacturer Std.	
RXS-FR-J13	Control Rod Cluster J13	B	I	Manufacturer Std.	
RXS-FR-K02	Control Rod Cluster K2	B	I	Manufacturer Std.	
RXS-FR-K04	Control Rod Cluster K4	B	I	Manufacturer Std.	
RXS-FR-K12	Control Rod Cluster K12	B	I	Manufacturer Std.	

Table 3.2-3 (Sheet 32 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-FR-K14	Control Rod Cluster K14	B	I	Manufacturer Std.	
RXS-FR-L03	Control Rod Cluster L3	B	I	Manufacturer Std.	
RXS-FR-L05	Control Rod Cluster L5	B	I	Manufacturer Std.	
RXS-FR-L07	Control Rod Cluster L7	B	I	Manufacturer Std.	
RXS-FR-L09	Control Rod Cluster L9	B	I	Manufacturer Std.	
RXS-FR-L11	Control Rod Cluster L11	B	I	Manufacturer Std.	
RXS-FR-L13	Control Rod Cluster L13	B	I	Manufacturer Std.	
RXS-FR-M06	Control Rod Cluster M6	B	I	Manufacturer Std.	
RXS-FR-M08	Control Rod Cluster M8	B	I	Manufacturer Std.	
RXS-FR-M10	Control Rod Cluster M10	B	I	Manufacturer Std.	
RXS-FR-N5	Control Rod Cluster N5	B	I	Manufacturer Std.	
RXS-FR-N7	Control Rod Cluster N7	B	I	Manufacturer Std.	
RXS-FR-N9	Control Rod Cluster N9	B	I	Manufacturer Std.	
RXS-FR-N11	Control Rod Cluster N11	B	I	Manufacturer Std.	
RXS-FR-P6	Control Rod Cluster P6	B	I	Manufacturer Std.	
RXS-FR-P10	Control Rod Cluster P10	B	I	Manufacturer Std.	
RXS-MI-01	Reactor Upper Internals	C	I	ASME III, CS	
RXS-MI-02	Reactor Lower Internals	C	I	ASME III, CS	
RXS-MI-10	Non-Threaded Fasteners	D	NS	ASME III, CS	

Table 3.2-3 (Sheet 33 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-MI-11	Threaded Structural Fasteners	C	I	ASME III, CS	
RXS-MI-20	Lower Core Support Plate	C	I	ASME III, CS	
RXS-MI-22	Vortex Suppression Plate	D	II	ASME III, CS	
RXS-MI-23	Core Shroud Assembly	C	II	ASME III, CS	
RXS-MI-24	Radial Supports [4]	C	I	ASME III, CS	
RXS-MI-25	Core Barrel	C	I	ASME III, CS	
RXS-MI-26	Core Barrel Nozzle	C	I	ASME III, CS	
RXS-MI-27	Head and Vessel Pins	D	II	ASME III, CS	
RXS-MI-28	Lower Support Plate Fuel Alignment Pins	C	I	ASME III, CS	
RXS-MI-29	Core Barrel Hold Down Spring	C	I	ASME III, CS	
RXS-MI-50	Upper Support	C	I	ASME III, CS	
RXS-MI-51	Upper Core Plate	C	I	ASME III, CS	
RXS-MI-52	Support Columns [42]	C	I	ASME III, CS	
RXS-MI-53	Guide Tube Assemblies [69]	C	I	ASME III, CS	
RXS-MI-54	Upper Support Plate Fuel Alignment Pins	C	I	ASME III, CS	
RXS-MI-55	Upper Core Plate Inserts	C	I	ASME III, CS	
RXS-MI-56	Safety Injection Deflector	D	II	ANSI B31.1	
RXS-MI-57	Irradiation Specimen Guide Tubes	D	II	ANSI B31.1	
RXS-MI-58	Head Cooling Nozzles	D	II	ANSI B31.1	
RXS-MV-10	Reactor Integrated Head Package	C	I	AISC-690	
RXS-MV-10A	Integrated Head Package Shroud	C	I	ASME-NF	
RXS-MV-10B	Integrated Head Package Seismic Support Plate	C	I	ASME-NF	
RXS-MV-11B06	Control Rod Drive Mechanism Position B6	D	NS	Manufacturer Std.	
RXS-MV-11B06L	CRDM Latch Housing B6	A	I	ASME III-1	
RXS-MV-11B06R	CRDM Rod Travel Housing B6	A	I	ASME III-1	

Table 3.2-3 (Sheet 34 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-MV-11B08	Control Rod Drive Mechanism Position B8	D	NS	Manufacturer Std.	
RXS-MV-11B08L	CRDM Latch Housing B8	A	I	ASME III-1	
RXS-MV-11B08R	CRDM Rod Travel Housing B8	A	I	ASME III-1	
RXS-MV-11B10	Control Rod Drive Mechanism Position B10	D	NS	Manufacturer Std.	
RXS-MV-11B10L	CRDM Latch Housing B10	A	I	ASME III-1	
RXS-MV-11B10R	CRDM Rod Travel Housing B10	A	I	ASME III-1	
RXS-MV-11C05	Control Rod Drive Mechanism Position C5	D	NS	Manufacturer Std.	
RXS-MV-11C05L	CRDM Latch Housing C5	A	I	ASME III-1	
RXS-MV-11C05R	CRDM Rod Travel Housing C5	A	I	ASME III-1	
RXS-MV-11C07	Control Rod Drive Mechanism Position C7	D	NS	Manufacturer Std.	
RXS-MV-11C07L	CRDM Latch Housing C7	A	I	ASME III-1	
RXS-MV-11C07R	CRDM Rod Travel Housing C7	A	I	ASME III-1	
RXS-MV-11C09	Control Rod Drive Mechanism Position C9	D	NS	Manufacturer Std.	
RXS-MV-11C09L	CRDM Latch Housing C9	A	I	ASME III-1	
RXS-MV-11C09R	CRDM Rod Travel Housing C9	A	I	ASME III-1	
RXS-MV-11C11	Control Rod Drive Mechanism Position C11	D	NS	Manufacturer Std.	
RXS-MV-11C11L	CRDM Latch Housing C11	A	I	ASME III-1	
RXS-MV-11C11R	CRDM Rod Travel Housing C11	A	I	ASME III-1	
RXS-MV-11D04	Control Rod Drive Mechanism Position D4	D	NS	Manufacturer Std.	
RXS-MV-11D04L	CRDM Latch Housing D4	A	I	ASME III-1	
RXS-MV-11D04R	CRDM Rod Travel Housing D4	A	I	ASME III-1	

Table 3.2-3 (Sheet 35 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-MV-11D06	Control Rod Drive Mechanism Position D6	D	NS	Manufacturer Std.	
RXS-MV-11D06L	CRDM Latch Housing D6	A	I	ASME III-1	
RXS-MV-11D06R	CRDM Rod Travel Housing D6	A	I	ASME III-1	
RXS-MV-11D08	Control Rod Drive Mechanism Position D8	D	NS	Manufacturer Std.	
RXS-MV-11D08L	CRDM Latch Housing D8	A	I	ASME III-1	
RXS-MV-11D08R	CRDM Rod Travel Housing D8	A	I	ASME III-1	
RXS-MV-11D10	Control Rod Drive Mechanism Position D10	D	NS	Manufacturer Std.	
RXS-MV-11D10L	CRDM Latch Housing D10	A	I	ASME III-1	
RXS-MV-11D10R	CRDM Rod Travel Housing D10	A	I	ASME III-1	
RXS-MV-11D12	Control Rod Drive Mechanism Position D12	D	NS	Manufacturer Std.	
RXS-MV-11D12L	CRDM Latch Housing D12	A	I	ASME III-1	
RXS-MV-11D12R	CRDM Rod Travel Housing D12	A	I	ASME III-1	
RXS-MV-11E03	Control Rod Drive Mechanism Position E3	D	NS	Manufacturer Std.	
RXS-MV-11E03L	CRDM Latch Housing E3	A	I	ASME III-1	
RXS-MV-11E03R	CRDM Rod Travel Housing E3	A	I	ASME III-1	
RXS-MV-11E05	Control Rod Drive Mechanism Position E5	D	NS	Manufacturer Std.	
RXS-MV-11E05L	CRDM Latch Housing E5	A	I	ASME III-1	
RXS-MV-11E05R	CRDM Rod Travel Housing E5	A	I	ASME III-1	
RXS-MV-11E07	Control Rod Drive Mechanism Position E7	D	NS	Manufacturer Std.	
RXS-MV-11E07L	CRDM Latch Housing E7	A	I	ASME III-1	
RXS-MV-11E07R	CRDM Rod Travel Housing E7	A	I	ASME III-1	

Table 3.2-3 (Sheet 36 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-MV-11E09	Control Rod Drive Mechanism Position E9	D	NS	Manufacturer Std.	
RXS-MV-11E09L	CRDM Latch Housing E9	A	I	ASME III-1	
RXS-MV-11E09R	CRDM Rod Travel Housing E9	A	I	ASME III-1	
RXS-MV-11E11	Control Rod Drive Mechanism Position E11	D	NS	Manufacturer Std.	
RXS-MV-11E11L	CRDM Latch Housing E11	A	I	ASME III-1	
RXS-MV-11E11R	CRDM Rod Travel Housing E11	A	I	ASME III-1	
RXS-MV-11E13	Control Rod Mechanism Position E13	D	NS	Manufacturer Std.	
RXS-MV-11E13L	CRDM Latch Housing E13	A	I	ASME III-1	
RXS MV-11E13R	CRDM Rod Travel Housing E13	A	I	ASME III-1	
RXS-MV-11F02	Control Rod Drive Mechanism Position F2	D	NS	Manufacturer Std.	
RXS-MV-11F02L	CRDM Latch Housing F2	A	I	ASME III-1	
RXS-MV-11F02R	CRDM Rod Travel Housing F2	A	I	ASME III-1	
RXS-MV-11F04	Control Rod Drive Mechanism Position F4	D	NS	Manufacturer Std.	
RXS-MV-11F04L	CRDM Latch Housing F4	A	I	ASME III-1	
RXS-MV-11F04R	CRDM Rod Travel Housing F4	A	I	ASME III-1	
RXS-MV-11F06	Control Rod Drive Mechanism Position F6	D	NS	Manufacturer Std.	
RXS-MV-11F06L	CRDM Latch Housing F6	A	I	ASME III-1	
RXS-MV-11F06R	CRDM Rod Travel Housing F6	A	I	ASME III-1	
RXS-MV-11F08	Control Rod Drive Mechanism Position F8	D	NS	Manufacturer Std.	
RXS-MV-11F08L	CRDM Latch Housing F8	A	I	ASME III-1	
RXS-MV-11F08R	CRDM Rod Travel Housing F8	A	I	ASME III-1	

Table 3.2-3 (Sheet 37 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-MV-11F10	Control Rod Drive Mechanism Position F10	D	NS	Manufacturer Std.	
RXS-MV-11F10L	CRDM Latch Housing F10	A	I	ASME III-1	
RXS-MV-11F10R	CRDM Rod Travel Housing F10	A	I	ASME III-1	
RXS-MV-11F12	Control Rod Drive Mechanism Position F12	D	NS	Manufacturer Std.	
RXS-MV-11F12L	CRDM Latch Housing F12	A	I	ASME III-1	
RXS-MV-11F12R	CRDM Rod Travel Housing F12	A	I	ASME III-1	
RXS-MV-11F14	Control Rod Drive Mechanism Position F14	D	NS	Manufacturer Std.	
RXS-MV-11F14L	CRDM Latch Housing F14	A	I	ASME III-1	
RXS-MV-11F14R	CRDM Rod Travel Housing F14	A	I	ASME III-1	
RXS-MV-11G03	Control Rod Drive Mechanism Position G3	D	NS	Manufacturer Std.	
RXS-MV-11G03L	CRDM Latch Housing G3	A	I	ASME III-1	
RXS-MV-11G03R	CRDM Rod Travel Housing G3	A	I	ASME III-1	
RXS-MV-11G05	Control Rod Drive Mechanism Position G5	D	NS	Manufacturer Std.	
RXS-MV-11G05L	CRDM Latch Housing G5	A	I	ASME III-1	
RXS-MV-11G05R	CRDM Rod Travel Housing G5	A	I	ASME III-1	
RXS-MV-11G07	Control Rod Drive Mechanism Position G7	D	NS	Manufacturer Std.	
RXS-MV-11G07L	CRDM Latch Housing G7	A	I	ASME III-1	
RXS-MV-11G07R	CRDM Rod Travel Housing G7	A	I	ASME III-1	
RXS-MV-11G09	Control Rod Drive Mechanism Position G9	D	NS	Manufacturer Std.	
RXS-MV-11G09L	CRDM Latch Housing G9	A	I	ASME III-1	
RXS-MV-11G09R	CRDM Rod Travel Housing G9	A	I	ASME III-1	

Table 3.2-3 (Sheet 38 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-MV-11G11	Control Rod Drive Mechanism Position G11	D	NS	Manufacturer Std.	
RXS-MV-11G11L	CRDM Latch Housing G11	A	I	ASME III-1	
RXS-MV-11G11R	CRDM Rod Travel Housing G11	A	I	ASME III-1	
RXS-MV-11G13	Control Rod Drive Mechanism Position G13	D	NS	Manufacturer Std.	
RXS-MV-11G13L	CRDM Latch Housing G13	A	I	ASME III-1	
RXS-MV-11G13R	CRDM Rod Travel Housing G13	A	I	ASME III-1	
RXS-MV-11H02	Control Rod Drive Mechanism Position H2	D	NS	Manufacturer Std.	
RXS-MV-11H02L	CRDM Latch Housing H2	A	I	ASME III-1	
RXS-MV-11H02R	CRDM Rod Travel Housing H2	A	I	ASME III-1	
RXS-MV-11H04	Control Rod Drive Mechanism Position H4	D	NS	Manufacturer Std.	
RXS-MV-11H04L	CRDM Latch Housing H4	A	I	ASME III-1	
RXS-MV-11H04R	CRDM Rod Travel Housing H4	A	I	ASME III-1	
RXS-MV-11H06	Control Rod Drive Mechanism Position H6	D	NS	Manufacturer Std.	
RXS-MV-11H06L	CRDM Latch Housing H6	A	I	ASME III-1	
RXS-MV-11H06R	CRDM Rod Travel Housing H6	A	I	ASME III-1	
RXS-MV-11H08	Control Rod Drive Mechanism Position H8	D	NS	Manufacturer Std.	
RXS-MV-11H08L	CRDM Latch Housing H8	A	I	ASME III-1	
RXS-MV-11H08R	CRDM Rod Travel Housing H8	A	I	ASME III-1	
RXS-MV-11H10	Control Rod Drive Mechanism Position H10	D	NS	Manufacturer Std.	
RXS-MV-11H10L	CRDM Latch Housing H10	A	I	ASME III-1	
RXS-MV-11H10R	CRDM Rod Travel Housing H10	A	I	ASME III-1	

Table 3.2-3 (Sheet 39 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-MV-11H12	Control Rod Drive Mechanism Position H12	D	NS	Manufacturer Std.	
RXS-MV-11H12L	CRDM Latch Housing H12	A	I	ASME III-1	
RXS-MV-11H12R	CRDM Rod Travel Housing H12	A	I	ASME III-1	
RXS-MV-11H14	Control Rod Drive Mechanism Position H14	D	NS	Manufacturer Std.	
RXS-MV-11H14L	CRDM Latch Housing H14	A	I	ASME III-1	
RXS-MV-11H14R	CRDM Rod Travel Housing H14	A	I	ASME III-1	
RXS-MV-11J03	Control Rod Drive Mechanism Position J3	D	NS	Manufacturer Std.	
RXS-MV-11J03L	CRDM Latch Housing J3	A	I	ASME III-1	
RXS-MV-11J03R	CRDM Rod Travel Housing J3	A	I	ASME III-1	
RXS-MV-11J05	Control Rod Drive Mechanism Position J5	D	NS	Manufacturer Std.	
RXS-MV-11J05L	CRDM Latch Housing J5	A	I	ASME III-1	
RXS-MV-11J05R	CRDM Rod Travel Housing J5	A	I	ASME III-1	
RXS-MV-11J07	Control Rod Drive Mechanism Position J7	D	NS	Manufacturer Std.	
RXS-MV-11J07L	CRDM Latch Housing J7	A	I	ASME III-1	
RXS-MV-11J07R	CRDM Rod Travel Housing J7	A	I	ASME III-1	
RXS-MV-11J09	Control Rod Drive Mechanism Position J9	D	NS	Manufacturer Std.	
RXS-MV-11J09L	CRDM Latch Housing J9	A	I	ASME III-1	
RXS-MV-11J09R	CRDM Rod Travel Housing J9	A	I	ASME III-1	
RXS-MV-11J11	Control Rod Drive Mechanism Position J11	D	NS	Manufacturer Std.	
RXS-MV-11J11L	CRDM Latch Housing J11	A	I	ASME III-1	
RXS-MV-11J11R	CRDM Rod Travel Housing J11	A	I	ASME III-1	

Table 3.2-3 (Sheet 40 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-MV-11J13	Control Rod Drive Mechanism Position J13	D	NS	Manufacturer Std.	
RXS-MV-11J13L	CRDM Latch Housing J13	A	I	ASME III-1	
RXS-MV-11J13R	CRDM Rod Travel Housing J13	A	I	ASME III-1	
RXS-MV-11K02	Control Rod Drive Mechanism Position K2	D	NS	Manufacturer Std.	
RXS-MV-11K02L	CRDM Latch Housing K2	A	I	ASME III-1	
RXS-MV-11K02R	CRDM Rod Travel Housing K2	A	I	ASME III-1	
RXS-MV-11K04	Control Rod Drive Mechanism Position K4	D	NS	Manufacturer Std.	
RXS-MV-11K04L	CRDM Latch Housing K4	A	I	ASME III-1	
RXS-MV-11K04R	CRDM Rod Travel Housing K4	A	I	ASME III-1	
RXS-MV-11K06	Control Rod Drive Mechanism Position K6	D	NS	Manufacturer Std.	
RXS-MV-11K06L	CRDM Latch Housing K6	A	I	ASME III-1	
RXS-MV-11K06R	CRDM Rod Travel Housing K6	A	I	ASME III-1	
RXS-MV-11K08	Control Rod Drive Mechanism Position K8	D	NS	Manufacturer Std.	
RXS-MV-11K08L	CRDM Latch Housing K8	A	I	ASME III-1	
RXS-MV-11K08R	CRDM Rod Travel Housing K8	A	I	ASME III-1	
RXS-MV-11K10	Control Rod Drive Mechanism Position K10	D	NS	Manufacturer Std.	
RXS-MV-11K10L	CRDM Latch Housing K10	A	I	ASME III-1	
RXS-MV-11K10R	CRDM Rod Travel Housing K10	A	I	ASME III-1	
RXS-MV-11K12	Control Rod Drive Mechanism Position K12	D	NS	Manufacturer Std.	
RXS-MV-11K12L	CRDM Latch Housing K12	A	I	ASME III-1	
RXS-MV-11K12R	CRDM Rod Travel Housing K12	A	I	ASME III-1	

Table 3.2-3 (Sheet 41 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-MV-11K14	Control Rod Drive Mechanism Position K14	D	I	Manufacturer Std.	
RXS-MV-11K14L	CRDM Latch Housing K14	A	I	ASME III-1	
RXS-MV-11K14R	CRDM Rod Travel Housing K14	A	I	ASME III-1	
RXS-MV-11L03	Control Rod Drive Mechanism Position L3	D	NS	Manufacturer Std.	
RXS-MV-11L03L	CRDM Latch Housing L3	A	I	ASME III-1	
RXS-MV-11L03R	CRDM Rod Travel Housing L3	A	I	ASME III-1	
RXS-MV-11L05	Control Rod Drive Mechanism Position L5	D	NS	Manufacturer Std.	
RXS-MV-11L05L	CRDM Latch Housing L5	A	I	ASME III-1	
RXS-MV-11L05R	CRDM Rod Travel Housing L5	A	I	ASME III-1	
RXS-MV-11L07	Control Rod Drive Mechanism Position L7	D	NS	Manufacturer Std.	
RXS-MV-11L07L	CRDM Latch Housing L7	A	I	ASME III-1	
RXS-MV-11L07R	CRDM Rod Travel Housing L7	A	I	ASME III-1	
RXS-MV-11L09	Control Rod Drive Mechanism Position L9	D	NS	Manufacturer Std.	
RXS-MV-11L09L	CRDM Latch Housing L9	A	I	ASME III-1	
RXS-MV-11L09R	CRDM Rod Travel Housing L9	A	I	ASME III-1	
RXS-MV-11L11	Control Rod Drive Mechanism Position L11	D	NS	Manufacturer Std.	
RXS-MV-11L11L	CRDM Latch Housing L11	A	I	ASME III-1	
RXS-MV-11L11R	CRDM Rod Travel Housing L11	A	I	ASME III-1	
RXS-MV-11L13	Control Rod Drive Mechanism Position L13	D	I	Manufacturer Std.	
RXS-MV-11L13L	CRDM Latch Housing L13	A	I	ASME III-1	
RXS-MV-11L13R	CRDM Rod Travel Housing L13	A	I	ASME III-1	

Table 3.2-3 (Sheet 42 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-MV-11M04	Control Rod Drive Mechanism Position M4	D	NS	Manufacturer Std.	
RXS-MV-11M04L	CRDM Latch Housing M4	A	I	ASME III-1	
RXS-MV-11M04R	CRDM Rod Travel Housing M4	A	I	ASME III-1	
RXS-MV-11M06	Control Rod Drive Mechanism Position M6	D	NS	Manufacturer Std.	
RXS-MV-11M06L	CRDM Latch Housing M6	A	I	ASME III-1	
RXS-MV-11M06R	CRDM Rod Travel Housing M6	A	I	ASME III-1	
RXS-MV-11M08	Control Rod Drive Mechanism Position M8	D	NS	Manufacturer Std.	
RXS-MV-11M08L	CRDM Latch Housing M8	A	I	ASME III-1	
RXS-MV-11M08R	CRDM Rod Travel Housing M8	A	I	ASME III-1	
RXS-MV-11M10	Control Rod Drive Mechanism Position M10	D	NS	Manufacturer Std.	
RXS-MV-11M10L	CRDM Latch Housing M10	A	I	ASME III-1	
RXS-MV-11M10R	CRDM Rod Travel Housing M10	A	I	ASME III-1	
RXS-MV-11M12	Control Rod Drive Mechanism Position M12	D	NS	Manufacturer Std.	
RXS-MV-11M12L	CRDM Latch Housing M12	A	I	ASME III-1	
RXS-MV-11M12R	CRDM Rod Travel Housing M12	A	I	ASME III-1	
RRXS-MV-11N05	Control Rod Drive Mechanism Position N05	D	NS	Manufacturer Std.	
RXS-MV-11N05L	CRDM Latch Housing N5	A	I	ASME III-1	
RXS-MV-11N05R	CRDM Rod Travel Housing N5	A	I	ASME III-1	
RXS-MV-11N07	Control Rod Drive Mechanism Position N7	D	NS	Manufacturer Std.	
RXS-MV-11N07L	CRDM Latch Housing N7	A	I	ASME III-1	

Table 3.2-3 (Sheet 43 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Reactor System (Continued)					
RXS-MV-11N07R	CRDM Rod Travel Housing N7	A	I	ASME III-1	
RXS-MV-11N09	Control Rod Drive Mechanism Position N09	D	NS	Manufacturer Std.	
RXS-MV-11N09L	CRDM Latch Housing N9	A	I	ASME III-1	
RXS-MV-11N09R	CRDM Rod Travel Housing N9	A	I	ASME III-1	
RXS-MV-11N11	Control Rod Drive Mechanism Position N11	D	NS	Manufacturer Std.	
RXS-MV-11N11L	CRDM Latch Housing N11	A	I	ASME III-1	
RXS-MV-11N11R	CRDM Rod Travel Housing N11	A	I	ASME III-1	
RXS-MV-11P06	Control Rod Drive Mechanism Position P6	D	NS	Manufacturer Std.	
RXS-MV-11P06L	CRDM Latch Housing P6	A	I	ASME III-1	
RXS-MV-11P06R	CRDM Rod Travel Housing P6	A	I	ASME III-1	
RXS-MV-11P08	Control Rod Drive Mechanism Position P8	D	NS	Manufacturer Std.	
RXS-MV-11P08L	CRDM Latch Housing P8	A	I	ASME III-1	
RXS-MV-11P08R	CRDM Rod Travel Housing P8	A	I	ASME III-1	
RXS-MV-11P10	Control Rod Drive Mechanism Position P10	D	I	Manufacturer Std.	
RXS-MV-11P10L	CRDM Latch Housing P10	A	I	ASME III-1	
RXS-MV-11P10R	CRDM Rod Travel Housing P10	A	I	ASME III-1	
RXS-MY-Y01	Irradiation Tube Plug Seat Jack	D	NS	Manufacturer Std.	
Balance of system components are Class E					
Sanitary Drainage System (SDS)					Location: Various
System components are Class P					

Table 3.2-3 (Sheet 44 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Spent Fuel Pool Cooling System (SFS)			Location: Auxiliary Building, Containment		
n/a	Heat Exchangers, SFS and CCS Side	D	NS	ASME VIII	
n/a	Pumps	D	NS	Hydraulic Institute Std.	
n/a	Demineralizers	D	NS	ASME VIII	
n/a	Filters	D	NS	ASME VIII	
n/a	Valves Providing SFS AP1000 Equipment Class D Function	D	NS	ANSI 16.34	
SFS-PL-V024A	Spent Fuel Pool Level Instrument Isolation	C	I	ASME III-3	
SFS-PL-V024B	Spent Fuel Pool Level Instrument Isolation	C	I	ASME III-3	
SFS-PL-V024C	Spent Fuel Pool Level Instrument Isolation	C	I	ASME III-3	
SFS-PL-V028	Cask Washdown Pit Level Instrument Isolation	C	I	ASME III-3	
SFS-PL-V031	SFS Refueling Cavity Drain to SGS Compartment Isolation	C	I	ASME III-3	
SFS-PL-V032	SFS Refueling Cavity Suction Isolation	C	I	ASME III-3	
SFS-PL-V033	SFS Refueling Cavity Drain to Containment Sump Isolation	C	I	ASME III-3	
SFS-PL-V034	SFS Suction Line Containment Isolation	B	I	ASME III-2	
SFS-PL-V035	SFS Suction Line Containment Isolation	B	I	ASME III-2	
SFS-PL-V037	SFS Discharge Line Containment Isolation	B	I	ASME III-2	
SFS-PL-V038	SFS Discharge Line Containment Isolation	B	I	ASME III-2	
SFS-PL-V039	SFS Suction Line from IRWST Isolation	C	I	ASME III-3	
SFS-PL-V040	SFS Fuel Transfer Canal Drain Isolation	C	I	ASME III-3	

Table 3.2-3 (Sheet 45 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Spent Fuel Pool Cooling System (Continued)					
SFS-PL-V041	SFS Cask Loading Pit Drain Isolation	C	I	ASME III-3	
SFS-PL-V042	Cask Loading Pit to Pump Suction Isolation	C	I	ASME III-3	
SFS-PL-V043	SFS CVS Makeup Reverse Flow Prevention	C	I	ASME III-3	
SFS-PL-V05	SFS Discharge to Cask Loading Pit Isolation	C	I	ASME III-3	
SFS-PL-V047	SFS Demineralized Water Makeup to SFP Reverse Flow Prevent	C	I	ASME III-3	
SFS-PL-V048	SFS Containment Penetration Test Connection	B	I	ASME III-2	
SFS-PL-V049	SFS Cask Loading Pit Drain to WLS Isolation	C	I	ASME III-3	
SFS-PL-V056	SFS Containment Penetration Test Connection Isolation	B	I	ASME III-2	
SFS-PL-V058	SFS Containment Isolation Valve V034 Test	C	I	ASME III-3	
SFS-PL-V066	Spent Fuel Pool to Cask Washdown Pit Isolation	C	I	ASME III-3	
SFS-PL-V068	Cask Washdown Pit Drain Isolation	C	I	ASME III-3	
Steam Generator System (SGS)			Location: Containment and Auxiliary Building		
SFS-PL-V071	Refueling Cavity Overflow to SG Compartment	C	I	ASME III-3	
SFS-PL-V072	Refueling Cavity Overflow to SG Compartment	C	I	ASME III-3	
SFS-PY-C01	Spent Fuel Cooling Pump Discharge to IRWST	B	I	ASME III, MC	
SFS-PY-C02	Spent Fuel Cooling Pump Suction from IRWST	B	I	ASME III, MC	
Balance of system components are Class D					

Table 3.2-3 (Sheet 46 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Steam Generator System (Continued)					
SGS-MY-Y01A	Steam Generator A PORV Silencer	D	NS	Manufacturer Std.	
SGS-MY-Y01B	Steam Generator B PORV Silencer	D	NS	Manufacturer Std.	
SGS-PL-V001A	LT001 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V001B	LT005 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V002A	LT001 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V002B	LT005 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V003A	LT002 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V003B	LT006 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V004A	LT002 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V004B	LT006 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V005A	LT003 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V005B	LT007 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V006A	LT003 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V006B	LT007 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V007A	LT004 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V007B	LT008 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V008A	LT004 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V008B	LT008 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V010A	LT011 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V010B	LT013 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V011A	LT011 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V011B	LT013 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V012A	LT012 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V012B	LT014 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V013A	LT012 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V013B	LT014 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V014A	PORV Discharge Condensate Drain Isolation	D	NS	ANSI B31.1	
SGS-PL-V014B	PORV Discharge Condensate Drain Isolation	D	NS	ANSI B31.1	
SGS-PL-V015A	FT021 Root Isolation Valve	B	I	ASME III-2	

Table 3.2-3 (Sheet 47 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Steam Generator System (Continued)					
SGS-PL-V015B	FT023 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V016A	FT020 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V016B	FT022 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V017A	FT021 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V017B	FT023 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V018A	FT020 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V018B	FT022 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V019A	Main Steam Line Vent Isolation	B	I	ASME III-2	
SGS-PL-V019B	Main Steam Line Vent Isolation	B	I	ASME III-2	
SGS-PL-V022A	PT030 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V022B	PT034 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V023A	PT031 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V023B	PT035 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V024A	PT032 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V024B	PT036 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V025A	PT033 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V025B	PT037 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V027A	PORV Block Valve SG 01	B	I	ASME III-2	
SGS-PL-V027B	PORV Block Valve SG 02	B	I	ASME III-2	
SGS-PL-V030A	Main Steam Safety Valve SG 01	B	I	ASME III-2	
SGS-PL-V030B	Main Steam Safety Valve SG 02	B	I	ASME III-2	
SGS-PL-V031A	Main Steam Safety Valve SG 01	B	I	ASME III-2	
SGS-PL-V031B	Main Steam Safety Valve SG 02	B	I	ASME III-2	
SGS-PL-V032A	Main Steam Safety Valve SG 01	B	I	ASME III-2	
SGS-PL-V032B	Main Steam Safety Valve SG 02	B	I	ASME III-2	

Table 3.2-3 (Sheet 48 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Steam Generator System (Continued)					
SGS-PL-V033A	Main Steam Safety Valve SG 01	B	I	ASME III-2	
SGS-PL-V033B	Main Steam Safety Valve SG 02	B	I	ASME III-2	
SGS-PL-V034A	Main Steam Safety Valve SG 01	B	I	ASME III-2	
SGS-PL-V034B	Main Steam Safety Valve SG 02	B	I	ASME III-2	
SGS-PL-V035A	Main Steam Safety Valve SG 01	B	I	ASME III-2	
SGS-PL-V035B	Main Steam Safety Valve SG 02	B	I	ASME III-2	
SGS-PL-V036A	Steam Line Condensate Drain Isolation	B	I	ASME III-2	
SGS-PL-V036B	Steam Line Condensate Drain Isolation	B	I	ASME III-2	
SGS-PL-V038A	Steam Line #1 Nitrogen Supply Isolation	B	I	ASME III-2	
SGS-PL-V038B	Steam Line #2 Nitrogen Supply Isolation	B	I	ASME III-2	
SGS-PL-V040A	Main Steam Line Isolation	B	I	ASME III-2	
SGS-PL-V040B	Main Steam Line Isolation	B	I	ASME III-2	
SGS-PL-V042A	MSIV Bypass Control Isolation	B	I	ASME III-2	
SGS-PL-V042B	MSIV Bypass Control Isolation	B	I	ASME III-2	
SGS-PL-V043A	MSIV Bypass Control Isolation	C	I	ASME III-3	
SGS-PL-V043B	MSIV Bypass Control Isolation	C	I	ASME III-3	
SGS-PL-V045A	SG 1 Condensate Pipe Drain Valve	B	I	ASME III-2	
SGS-PL-V045B	SG 2 Condensate Pipe Drain Valve	B	I	ASME III-2	
SGS-PL-V046A	LT015 Root Isolation Valve	B	I	ASME III-2	

Table 3.2-3 (Sheet 49 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Steam Generator System (Continued)					
SGS-PL-V046B	LT017 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V047A	LT015 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V047B	LT017 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V048A	LT016 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V048B	LT018 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V049A	LT016 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V049B	LT018 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V050A	LT044 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V050B	LT046 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V051A	LT044 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V051B	LT046 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V052A	LT045 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V052B	LT047 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V053A	LT045 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V053B	LT047 Root Isolation Valve	B	I	ASME III-2	
SGS-PL-V056A	PT062 Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V056B	PT063 Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V057A	Main Feedwater Isolation	B	I	ASME III-2	
SGS-PL-V057B	Main Feedwater Isolation	B	I	ASME III-2	
SGS-PL-V058A	Main Feedwater Check	B	I	ASME III-2	
SGS-PL-V058B	Main Feedwater Check	B	I	ASME III-2	
SGS-PL-V062A	FT055A Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V062B	FT056A Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V063A	FT055A Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V063B	FT056A Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V064A	FT055A Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V064B	FT056A Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V065A	FT055A Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V065B	FT056A Root Isolation Valve	C	I	ASME III-3	
SGS-PL-V067A	Startup Feedwater Isolation	B	I	ASME III-2	
SGS-PL-V067B	Startup Feedwater Isolation	B	I	ASME III-2	
SGS-PL-V074A	SG Blowdown Isolation	B	I	ASME III-2	

Table 3.2-3 (Sheet 50 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Steam Generator System (Continued)					
SGS-PL-V074B	SG Blowdown Isolation	B	I	ASME III-2	
SGS-PL-V075A	SG Series Blowdown Isolation	C	I	ASME III-3	
SGS-PL-V075B	SG Series Blowdown Isolation	C	I	ASME III-3	
SGS-PL-V084A	SG 1 Nitrogen Sparging Isolation	B	I	ASME III-2	
SGS-PL-V084B	SG 2 Nitrogen Sparging Isolation	B	I	ASME III-2	
SGS-PL-V086A	Steam Line Condensate Drain Control	C	I	ASME III-3	
SGS-PL-V086B	Steam Line Condensate Drain Control	C	I	ASME III-3	
SGS-PL-V233A	Power Operated Relief Valve	C	I	ASME III-3	
SGS-PL-V233B	Power Operated Relief Valve	C	I	ASME III-3	
SGS-PL-V240A	MSIV Bypass Isolation	B	I	ASME III-2	
SGS-PL-V240B	MSIV Bypass Isolation	B	I	ASME III-2	
SGS-PL-V250A	Main Feedwater Control	C	I	ASME III-3	
SGS-PL-V250B	Main Feedwater Control	C	I	ASME III-3	
SGS-PL-V255A	Startup Feedwater Control	C	I	ASME III-3	
SGS-PL-V255B	Startup Feedwater Control	C	I	ASME III-3	
SGS-PL-V256A	Startup Feedwater Check Valve	C	I	ASME III-3	
SGS-PL-V256B	Startup Feedwater Check Valve	C	I	ASME III-3	
SGS-PY-C01A	Main Steam Line A Penetration	B	I	ASME III, MC	
SGS-PY-C01B	Main Steam Line B Penetration	B	I	ASME III, MC	
SGS-PY-C02A	Main Feedwater Line A Penetration	B	I	ASME III, MC	
SGS-PY-C02B	Main Feedwater Line B Penetration	B	I	ASME III, MC	
SGS-PY-C03A	Steam Generator A Blowdown Line Penetration	B	I	ASME III, MC	

Table 3.2-3 (Sheet 51 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Steam Generator System (Continued)					
SGS-PY-C03B	Steam Generator B Blowdown Line Penetration	B	I	ASME III, MC	
SGS-PY-C05A	Startup Feedwater Line A Penetration	B	I	ASME III, MC	
SGS-PY-C05B	Startup Feedwater Line B Penetration	B	I	ASME III, MC	
Secondary Sampling System (SSS)					Location: Turbine Building
System components are Class E					
Service Water System (SWS)					Location: Turbine Building and Yard
n/a	Service Water Cooling Tower Fans	D	NS	Manufacturer Std.	
n/a	Service Water Cooling Tower	D	NS	Manufacturer Std.	
n/a	Service Water Pumps	D	NS	Hydraulic Institute Std.	
n/a	Valves Providing SWS AP1000 Equipment Class D Function	D	NS	ANSI 16.34	
Turbine Building Closed Cooling Water System (TCS)					Location: Turbine Building
System components are Class E					
Turbine Island Vents, Drains and Relief System (TDS)					Location: Turbine Building
n/a	Piping and components that provide the path from the GSS and CMS to atmosphere and rad monitor	D	NS	ANSI B31.1	
Balance of system components are Class E					
Main Turbine Control and Diagnostic System (TOS)					Location: Turbine Building
System components are Class E					
Radiologically Controlled Area Ventilation System (VAS)					Location: Auxiliary Building and Annex Building
n/a	CVS and RNS Pump Room Coolers	Note 2	NS	Manufacturer Std.	
n/a	Valves Providing VAS AP1000 Equipment Class D Function	D	NS	ANSI 16.34	

Table 3.2-3 (Sheet 52 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Radiologically Controlled Area Ventilation System (VAS) (Continued)					
n/a	Shutoff, Isolation, and Balancing Dampers	L	NS	ANSI/AMCA-500	
n/a	Fire Dampers	Note 3	NS	UL-555	
n/a	Air Handling Units	L	NS	Manufacturer Std.	
n/a	Filters	L	NS	UL 900	
n/a	Fans, Ductwork	L	NS	SMACNA	
Balance of system components are Class L					
Nuclear Island Nonradioactive Ventilation System (VBS)			Location: Auxiliary Building and Annex Building		
n/a	Battery Rooms Exhaust Fans	Note 2	NS	AMCA	
n/a	PCS Room Heaters	Note 2	NS	Manufacturer Std.	
n/a	Fire Dampers	Note 3	NS	UL-555S	
n/a	Dampers Providing AP1000 Equipment Class D Function	Note 2	NS	ANSI/AMCA-500	
n/a	Dampers in lines isolating radioactive contamination	R	NS	ASME-509	
n/a	Shutoff, Isolation, and Balancing Dampers	L	NS	ANSI/AMCA-500	
VBS-MP-01A	Sample Pump A	C	I	Manufacturer Std.	
VBS-MP-01B	Sample Pump B	C	I	Manufacturer Std.	
n/a	MCR/TSC Supplemental Air Filtration Units	Note 2	NS	ASME AG-1, Note 4	
VBS-PL-V164	MCR Penetration Test Valve	C	I	ASME III-3	
VBS-PL-V165	MCR Penetration Test Valve	C	I	ASME III-3	
VBS-PL-V166	MCR Isolation Test Valve	C	I	ASME III-3	
VBS-PL-V167	MCR Isolation Test Valve	C	I	ASME III-3	
VBS-PL-V168	MCR Isolation Test Valve	C	I	ASME III-3	
VBS-PL-V169	MCR Isolation Test Valve	C	I	ASME III-3	
VBS-PL-V186	MCR Isolation Valve	C	I	ASME III-3	
VBS-PL-V187	MCR Isolation Valve	C	I	ASME III-3	
VBS-PL-V188	MCR Isolation Valve	C	I	ASME III-3	

Table 3.2-3 (Sheet 53 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Nuclear Island Nonradioactive Ventilation System (VBS) (Continued)					
VBS-PL-V189	MCR Isolation Valve	C	I	ASME III-3	
VBS-PL-V190	MCR Isolation Valve	C	I	ASME III-3	
VBS-PL-V191	MCR Isolation Valve	C	I	ASME III-3	
n/a	Valves Providing VBS AP1000 Equipment Class D Function	D	NS	ANSI 16.34	
n/a	Other Air Handling Units	Note 2	NS	Manufacturer Std.	
n/a	Filters	Note 2	NS	UL 900	
n/a	Fans, Ductwork	Note 2, L or R	NS	SMACNA	
VBS-MA-10A	Ancillary Fan	D	NS	ANSI/AMCA 210, 211, 300	Equipment anchorage is Seismic Category II
VBS-MA-10B	Ancillary Fan	D	NS	ANSI/AMCA 210, 211, 300	Equipment anchorage is Seismic Category II
VBS-MA-11	Ancillary Fan	D	NS	ANSI/AMCA 210, 211, 300	Equipment anchorage is Seismic Category II
VBS-MA-12	Ancillary Fan	D	NS	ANSI/AMCA 210, 211, 300	Equipment anchorage is Seismic Category II
Balance of system components are Class L					
Containment Recirculation Cooling System (VCS)					Location: Containment
n/a	Dampers	L	NS	ANSI/AMCA-500	
n/a	Fan Coil Units	L	NS	Manufacturer Std.	
n/a	Fans, Ductwork	L	NS	SMACNA	
Balance of system components are Class L					

Table 3.2-3 (Sheet 54 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tab Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Main Control Room Emergency Habitability System (VES)				Location:	Auxiliary Building
VES-MD-D001A	Relief Damper	Note 1	I	ASME 509/510	
VES-MD-D001B	Relief Damper	Note 1	I	ASME 509/510	
VES-MT-01	Emergency Air Storage Tank 01	C	I	ASME VIII, Appendix 22	
VES-MT-02	Emergency Air Storage Tank 02	C	I	ASME VIII, Appendix 22	
VES-MT-03	Emergency Air Storage Tank 03	C	I	ASME VIII, Appendix 22	
VES-MT-04	Emergency Air Storage Tank 04	C	I	ASME VIII, Appendix 22	
VES-MT-05	Emergency Air Storage Tank 05	C	I	ASME VIII, Appendix 22	
VES-MT-06	Emergency Air Storage Tank 06	C	I	ASME VIII, Appendix 22	
VES-MT-07	Emergency Air Storage Tank 07	C	I	ASME VIII, Appendix 22	
VES-MT-08	Emergency Air Storage Tank 08	C	I	ASME VIII, Appendix 22	
VES-MT-09	Emergency Air Storage Tank 09	C	I	ASME VIII, Appendix 22	
VES-MT-10	Emergency Air Storage Tank 10	C	I	ASME VIII, Appendix 22	
VES-MT-11	Emergency Air Storage Tank 11	C	I	ASME VIII, Appendix 22	
VES-MT-12	Emergency Air Storage Tank 12	C	I	ASME VIII, Appendix 22	
VES-MT-13	Emergency Air Storage Tank 13	C	I	ASME VIII, Appendix 22	
VES-MT-14	Emergency Air Storage Tank 14	C	I	ASME VIII, Appendix 22	
VES-MT-15	Emergency Air Storage Tank 15	C	I	ASME VIII, Appendix 22	
VES-MT-16	Emergency Air Storage Tank 16	C	I	ASME VIII, Appendix 22	

Table 3.2-3 (Sheet 55 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Main Control Room Emergency Habitability System (Continued)					
VES-MT-17	Emergency Air Storage Tank 17	C	I	ASME VIII, Appendix 22	
VES-MT-18	Emergency Air Storage Tank 18	C	I	ASME VIII, Appendix 22	
VES-MT-19	Emergency Air Storage Tank 19	C	I	ASME VIII, Appendix 22	
VES-MT-20	Emergency Air Storage Tank 20	C	I	ASME VIII, Appendix 22	
VES-MT-21	Emergency Air Storage Tank 21	C	I	ASME VIII, Appendix 22	
VES-MT-22	Emergency Air Storage Tank 22	C	I	ASME VIII, Appendix 22	
VES-MT-23	Emergency Air Storage Tank 23	C	I	ASME VIII, Appendix 22	
VES-MT-24	Emergency Air Storage Tank 24	C	I	ASME VIII, Appendix 22	
VES-MT-25	Emergency Air Storage Tank 25	C	I	ASME VIII, Appendix 22	
VES-MT-26	Emergency Air Storage Tank 26	C	I	ASME VIII, Appendix 22	
VES-MT-27	Emergency Air Storage Tank 27	C	I	ASME VIII, Appendix 22	
VES-MT-28	Emergency Air Storage Tank 28	C	I	ASME VIII, Appendix 22	
VES-MT-29	Emergency Air Storage Tank 29	C	I	ASME VIII, Appendix 22	
VES-MT-30	Emergency Air Storage Tank 30	C	I	ASME VIII, Appendix 22	
VES-MT-31	Emergency Air Storage Tank 31	C	I	ASME VIII, Appendix 22	
VES-MT-32	Emergency Air Storage Tank 32	C	I	ASME VIII, Appendix 22	
VES-PL-V001	Air Delivery Alternate Isolation Valve	C	I	ASME III-3	

Table 3.2-3 (Sheet 56 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Main Control Room Emergency Habitability System (Continued)					
VES-PL-V002A	Pressure Regulating Valve A	C	I	ASME III-3	
VES-PL-V002B	Pressure Regulating Valve B	C	I	ASME III-3	
VES-PL-V005A	Air Delivery Main Isolation Valve A	C	I	ASME III-3	
VES-PL-V005B	Air Delivery Main Isolation Valve B	C	I	ASME III-3	
VES-PL-V006A	Air Delivery Line Pressure Instrument Isolation Valve A	C	I	ASME III-3	
VES-PL-V006B	Air Delivery Line Pressure Instrument Isolation Valve B	C	I	ASME III-3	
VES-PL-V008A	Refill CheckValve A	C	I	ASME III-3	
VES-PL-V008B	Refill CheckValve B	C	I	ASME III-3	
VES-PL-V016	Temporary Instrument Isolation Valve A	C	I	ASME III-3	
VES-PL-V018	Temporary Instrument Isolation Valve A	C	I	ASME III-3	
VES-PL-V019	Temporary Instrument Isolation Valve B	C	I	ASME III-3	
VES-PL-V020	Temporary Instrument Isolation Valve B	C	I	ASME III-3	
VES-PL-V022A	Pressure Relief Isolation Valve A	C	I	ASME III-3	
VES-PL-V022B	Pressure Relief Isolation Valve B	C	I	ASME III-3	
VES-PL-V024A	Air Tank Isolation Valve A	C	I	ASME III-3	
VES-PL-V024B	Air Tank Isolation Valve B	C	I	ASME III-3	
VES-PL-V025A	Air Tank Isolation Valve A	C	I	ASME III-3	
VES-PL-V025B	Air Tank Isolation Valve B	C	I	ASME III-3	
VES-PL-V038	Makeup Air Stop Valve	C	I	ASME III-3	
VES-PL-V040A	Air Tank Safety Relief Valve A	C	I	ASME III-3	
VES-PL-V040B	Air Tank Safety Relief Valve B	C	I	ASME III-3	
VES-PL-V041A	Air Tank Safety Relief Valve A	C	I	ASME III-3	

Table 3.2-3 (Sheet 57 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Main Control Room Emergency Habitability System (Continued)					
VES-PL-V041B	Air Tank Safety Relief Valve B	C	I	ASME III-3	
VES-PL-V042	Refill Header Manual Vent Valve	C	I	ASME III-3	
VES-PL-V043A	Differential Pressure Instrument Line Isolation Valve A	C	I	ASME III-3	
VES-PL-V043B	Differential Pressure Instrument Line Isolation Valve B	C	I	ASME III-3	
VES-PL-V044	Main Air Flowpath Isolation Valve	C	I	ASME III-3	
Containment Air Filtration System (VFS)			Location: Auxiliary Building and Annex Building		
VFS-PY-C01	Containment Supply Duct Penetration	B	I	ASME III, MC	
VFS-PY-C02	Containment Exhaust Duct Penetration	B	I	ASME III, MC	
VFS-MY-Y01	Containment Air Supply Debris Screen	C	I	ASME Sec. III Class 3	
VFS-MY-Y02	Containment Air Exhaust Debris Screen	C	I	ASME Sec. III Class 3	
VFS-PL-V001	Containment Isolation Test Connection	B	I	ASME III-2	
VFS-PL-V002	Containment Isolation Test Connection	C	I	ASME III-3	
VFS-PL-V003	Containment Purge Supply Containment Isolation Valve	B	I	ASME III-2	
VFS-PL-V004	Containment Purge Supply Containment Isolation Valve	B	I	ASME III-2	
VFS-PL-V006	Containment Isolation Test Connection	C	I	ASME III-3	
VFS-PL-V007	Containment Isolation Test Connection	B	I	ASME III-2	
VFS-PL-V008	Containment Isolation Test Connection	B	I	ASME III-2	

Table 3.2-3 (Sheet 58 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Containment Air Filtration System (Continued)					
VFS-PL-V009	Containment Purge Discharge Containment Isolation Valve	B	I	ASME III-2	
VFS-PL-V010	Containment Purge Discharge Containment Isolation Valve	B	I	ASME III-2	
VFS-PL-V012	Containment Isolation Test Connection	B	I	ASME III-2	
VFS-PL-V015	Containment Isolation Test Connection	B	I	ASME III-2	
n/a	Valves Providing VFS AP1000 Equipment Class D Function	D	NS	ANSI 16.34	
n/a	Dampers in lines isolating radioactive contamination	R	NS	ASME-509	
n/a	Shutoff, Isolation, and Balancing Dampers	L	NS	ANSI/AMCA-500	
n/a	Fire Dampers	Note 3	NS	UL-555	
n/a	Supply Air Handling Units	L	NS	Manufacturer Std.	
n/a	Air Exhaust Filtration Units	R	NS	ASME AG-1, Note 4	
n/a	Fans, Ductwork	L or R	NS	SMACNA or ASME AG-1, Note 4	
Balance of system components are Class L and Class R					
Health Physics and Hot Machine Shop HVAC System (VHS)					Location: Annex Building
n/a	Shutoff, Isolation, and Balancing Dampers	L	NS	ANSI/AMCA-500	
n/a	Fire Dampers	Note 3	NS	UL-555	
n/a	Air Handling Units w/ Filters	L	NS	Manufacturer Std.	
n/a	Fans, Ductwork	L	NS	SMACNA	
Balance of system components are Class E or Class L					

Table 3.2-3 (Sheet 59 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Containment Hydrogen Control System (VLS)					Location: Containment
n/a	Hydrogen Igniters	D	NS	Manufacturer Std.	Provides Hydrogen Control Following Severe Accidents
VLS-MY-E01A	Catalytic Hydrogen Recombiner A	D	NS	Manufacturer Std.	
VLS-MY-E01B	Catalytic Hydrogen Recombiner B	D	NS	Manufacturer Std.	
Balance of system components are Class E or Class L					
Radwaste Building Ventilation System (VRS)					Location: Radwaste Building
n/a	Shutoff, Isolation, and Balancing Dampers	L	NS	ANSI/AMCA-500	
n/a	Fire Damper	Note 3	NS	UL-555	
n/a	Air Handling Units	L	NS	Manufacturer Std.	
n/a	Filters	L	NS	UL 900	
n/a	Fans, Ductwork	L	NS	SMACNA	
Balance of system components are Class E or Class L					
Turbine Building Ventilation System (VTS)					Location: Turbine Building
n/a	Shutoff, Isolation, and Balancing Dampers	L	NS	ANSI/AMCA-500	
n/a	Fire Dampers	Note 3	NS	UL-555	
n/a	Air Handling Units w/ Filters	L	NS	Manufacturer Std., UL-900	
n/a	Fans, Ductwork	L	NS	SMACNA	
Balance of system components are Class L					
Containment Leak Rate Test System (VUS)					Location: Auxiliary Building
VUS-PL-V015	Main Equipment Hatch Test Connection	B	I	ASME III-2	
VUS-PL-V016	Maintenance Equipment Hatch Test Connection	B	I	ASME III-2	
VUS-PL-V017	Personnel Hatch Test Connection	B	I	ASME III-2	

Table 3.2-3 (Sheet 60 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Containment Leak Rate Test System (Continued)				Location:	Auxiliary Building
VUS-PL-V018	Personnel Hatch Test Connection	B	I	ASME III-2	
VUS-PL-V019	Personnel Hatch Test Connection	B	I	ASME III-2	
VUS-PL-V020	Personnel Hatch Test Connection	B	I	ASME III-2	
VUS-PL-V021	Personnel Hatch Test Connection	B	I	ASME III-2	
VUS-PL-V022	Personnel Hatch Test Connection	B	I	ASME III-2	
VUS-PL-V023	Fuel Transfer Tube Test Connection	B	I	ASME III-2	
VUS-PL-V101	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V102	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V103	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V104	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V109	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V110	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V111	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V112	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V113	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V114	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V115	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	

Table 3.2-3 (Sheet 61 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Containment Leak Rate Test System (Continued)					
VUS-PL-V116	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V117	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V118	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V119	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V120	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V121	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V122	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V123	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V124	Electrical Penetration Test Isolation Valve	B	I	ASME III-2	
VUS-PL-V140	Spare Penetration Test Connection	B	I	ASME III-2	
VUS-PL-V141	Spare Penetration Test Connection	B	I	ASME III-2	
VUS-PL-V142	Spare Penetration Test Connection	B	I	ASME III-2	
Balance of system components are Class E					
Central Chilled Water System (VWS)					Location: Various
n/a	Air Cooled Chiller	D	NS	Manufacturer Std.	
n/a	Pumps	D	NS	Manufacturer Std.	
n/a	Tanks	D	NS	ASME VIII	
n/a	Valves Providing VWS AP1000 Equipment Class D Function	D	NS	ANSI 16.34	

Table 3.2-3 (Sheet 62 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Central Chilled Water System (Continued)					
VWS-PY-C01	Containment Chilled Water Supply Penetration	B	I	ASME III, MC	
VWS-PY-C02	Containment Chilled Water Return Penetration	B	I	ASME III, MC	
VWS-PL-V058	Fan Coolers Supply Containment Isolation	B	I	ASME III-2	
VWS-PL-V062	Fan Coolers Supply Containment Isolation	B	I	ASME III-2	
VWS-PL-V082	Fan Coolers Return Containment Isolation	B	I	ASME III-2	
VWS-PL-V086	Fan Coolers Return Containment Isolation	B	I	ASME III-2	
VWS-PL-V424	Containment Penetration Test Connection	B	I	ASME III-2	
VWS-PL-V425	Containment Penetration Test Connection	B	I	ASME III-2	
Balance of system components are Class E					
Annex/Auxiliary Nonradioactive Ventilation System (VXS) Location: Auxiliary Building and Annex Building					
n/a	Air Handling Unit Fans Providing AP1000 Equipment Class D Function	Note 2	NS	AMCA	
n/a	Dampers Providing VXS AP1000 Equipment Class D Function	Note 2	NS	ANSI/AMCA-500	
n/a	Exhaust Fan Providing Ancillary Diesel Room Ventilation	Note 2	NS	AMCA	
n/a	Fire Dampers	Note 3	NS	UL-555 or UL-555S	
n/a	Air Handling Units	L	NS	Manufacturer Std.	
n/a	Filters	L	NS	UL 900	
n/a	Fans, Ductwork	L	NS	SMACNA	
Balance of system components are Class E or Class L					

Table 3.2-3 (Sheet 63 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Hot Water Heating System (VYS)					Location: Various
System components are Class E					
Diesel Generator Building Ventilation System (VZS)					Location: Diesel Generator Building
n/a	Unit Heaters Providing AP1000 Equipment Class D Function	Note 2	NS	UL-1025; NFPA 70	
n/a	Fans Providing AP1000 Equipment Class D Function	Note 2	NS	AMCA	
n/a	Dampers Providing VZS AP1000 Equipment Class D Function	Note 2	NS	AMCA	
n/a	Fire Dampers	Note 3	NS	UL-555	
n/a	Air Handling Units	L	NS	Manufacturer Std.	
n/a	Filters	L	NS	UL 900	
n/a	Fans, Ductwork	L	NS	SMACNA	
Balance of system components are Class E					
Gaseous Radwaste System (WGS)					Location: Auxiliary Building
n/a	Gas Cooler	D	NS	ASME VIII/ TEMA	
n/a	Sample Pumps	D	NS	Manufacturer Std.	
n/a	Guard and Delay Beds	D	NS	ASME VIII	Design for 1/2 SSE
n/a	Moisture Separator	D	NS	ASME VIII	
n/a	Valves Providing WGS AP1000 Equipment Class D Function	D	NS	ANSI 16.34	
Liquid Radwaste System (WLS)					Location: Containment and Auxiliary Building
n/a	Heat Exchangers, WLS and CCS Side	D	NS	ASME VIII/ TEMA	
n/a	Pumps	D	NS	Manufacturer Std.	
n/a	Tanks	D	NS	ASME III without Code Stamp	
n/a	Degasifier	D	NS	ASME VIII	

Table 3.2-3 (Sheet 64 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Liquid Radwaste System (Continued)					
n/a	Ion Exchangers	D	NS	ASME VIII	
n/a	Filters	D	NS	ASME VIII	
n/a	Valves Providing WLS AP1000 Equipment Class D Function (local drain valves in Radwaste Building)	D	NS	ANSI 16.34	
WLS-PL-V055	Sump Discharge Containment Isolation IRC	B	I	ASME III-2	
WLS-PL-V057	Sump Discharge Containment Isolation ORC	B	I	ASME III-2	
WLS-PL-V067	RCDT Gas Outlet Containment Isolation IRC	B	I	ASME III-2	
WLS-PL-V068	RCDT Gas Outlet Containment Isolation ORC	B	I	ASME III-2	
WLS-PL-V071A	CVS Compartment to Sump	C	I	ASME III-3	
WLS-PL-V071B	PXS A Compartment to Sump	C	I	ASME III-3	
WLS-PL-V071C	PXS B Compartment to Sump	C	I	ASME III-3	
WLS-PL-V072A	CVS Compartment to Sump	C	I	ASME III-3	
WLS-PL-V072B	PXS A Compartment to Sump	C	I	ASME III-3	
WLS-PL-V072C	PXS B Compartment to Sump	C	I	ASME III-3	
WLS-PY-C02	Reactor Coolant Drain Tank WLS Connection Penetration	B	I	ASME III, MC	
WLS-PY-C03	Containment Sump Pumps Combined Discharge Penetration	B	I	ASME III, MC	
Balance of system components are Class E					
Radioactive Waste Drain System (WRS)					Location: Auxiliary Building
n/a	Pumps	D	NS	Manufacturer Std.	
n/a	Valves Providing WRS AP1000 Equipment Class D Function	D	NS	ANSI 16.34	

Table 3.2-3 (Sheet 65 of 65)

AP1000 CLASSIFICATION OF MECHANICAL AND FLUID SYSTEMS, COMPONENTS, AND EQUIPMENT

Tag Number	Description	AP1000 Class	Seismic Category	Principal Construction Code	Comments
Solid Radwaste System (WSS)				Location: Auxiliary Building	
n/a	Pumps	D	NS	Manufacturer Std.	
n/a	Tanks	D	NS	ASME VIII	
n/a	Filters	D	NS	ASME VIII	
n/a	Valves Providing WSS AP1000 Equipment Class D Function	D	NS	ANSI 16.34	
Balance of system components are Class E					
Waste Water System (WWS)				Location: Various	
System components are Class E					
Onsite Standby Power System (ZOS)				Location: Diesel Generator Building	
n/a	Diesel Generator Engines	D	NS	Manufacturer Std.	
n/a	Diesel Generator Starting Units	D	NS	Manufacturer Std.	
n/a	Diesel Generator Radiators	D	NS	CAGI	
n/a	Diesel Generator Silencers	D	NS	API 661	
n/a	Valves Providing ZOS Diesel Generator Engines AP1000 Equipment Class D Function	D	NS	ANSI 16.34	
Balance of system components are Class E					

Notes:

1. Component performs a safety-related function equivalent to AP1000 equipment Class C. The component is constructed using the standards for Class R and a quality assurance program in conformance with 10 CFR Part 50 Appendix B.
2. Component performs an AP1000 equipment Class D function and is constructed using the standards for Class L or Class R.
3. Fire dampers are constructed to the requirements of UL-555 or UL-555S if they are fire and smoke dampers and are located in Class D, Class L, and Class R ducts.
4. Construction is non-seismic and meets applicable portions of ASME AG-1 consistent with RG 1.140.

3.3 Wind and Tornado Loadings

3.3.1 Wind Loadings

The wind loadings for seismic Category I structures are in accordance with American Society of Civil Engineers, "Minimum Design Loads for Buildings and Other Structures," ASCE 7-98 (Reference 1).

3.3.1.1 Design Wind Velocity

The design wind is specified as a basic wind speed of 145 mph with an annual probability of occurrence of 0.02 based on the most severe location identified in Reference 1. This wind speed is the 3 second gust speed at 33 feet above the ground in open terrain (Reference 1, exposure C). The basic wind speed of 145 mph is the 3 second gust speed that has become the basis of wind design codes since 1995. It corresponds to the 110 mph fastest mile wind used as the basis for the AP600 design in accordance with the 1988 edition of Reference 1.

Higher winds with a probability of occurrence of 0.01 are used in the design of seismic Category I structures by using an importance factor of 1.15. This is obtained by classifying the AP1000 seismic Category I structures as essential facilities and using the design provisions for Category IV of Reference 1.

Velocity pressure exposure coefficients and gust response factors are calculated according to Reference 1 for exposure C, which is applicable to shorelines in hurricane prone areas in the 1998 edition of Reference 1. The topographic factor is taken as unity.

The design wind loads calculated as described above exceed those required at other locations in the United States, where the more severe Exposure Category D is specified in Reference 1. Exposure Category D is applicable for sites near the open inland waterways, the Great Lakes, and the coastal areas of California, Oregon, Washington, and Alaska. For such locations, the basic wind speed is less than 130 mph.

3.3.1.2 Determination of Applied Forces

The procedures used in transforming the wind velocity into an effective pressure to be applied to structures and parts and portions of structures follow the guidelines of Reference 1.

Effective pressures applied to interior and exterior surfaces of the buildings and corresponding shape coefficients are calculated according to Reference 1 for exposure C. Shape coefficients, defining the variation around the circumference of the shield building, are calculated using ASCE Paper No. 3269 (Reference 2). These shape coefficients are consistent with those observed in the model tests described in Reference 6.

3.3.2 Tornado Loadings

Seismic Category I structures are designed to resist tornado wind loads without exceeding the allowable stresses defined in subsection 3.8.4. These tornado loads exceed the loads for hurricanes with a probability of occurrence comparable to that of the tornado. In addition, seismic Category I

structures are designed to remain functional when subjected to tornado-generated missiles as discussed in subsection 3.5.1.4. Seismic Category I structures are permitted to sustain local missile damage such as partial penetration and local cracking or permanent deformation or both, provided that structural integrity is maintained and seismic Category I systems, components, and equipment required to function during or after passage of a tornado are not subject to damage by secondary missiles, such as from concrete spalling. See subsection 3.5.2.

3.3.2.1 Applicable Design Parameters

The design parameters applicable to the design basis tornado are as follows:

- Maximum wind speed – 300 mph
- Maximum rotational speed – 240 mph
- Maximum translational speed – 60 mph
- Radius of maximum rotational wind from center of tornado – 150 ft
- Atmospheric pressure drop – 2.0 psi
- Rate of pressure change – 1.2 psi/sec

It is estimated that the probability of wind speeds greater than the design basis tornado is between 10^{-6} and 10^{-7} per year for an AP1000 at a "worst location" anywhere within the contiguous United States.

3.3.2.2 Determination of Forces on Structures

The procedures described in subsection 3.3.1.2 are used to transform the tornado wind loading and differential pressure loading into effective loads on structures, with a wind velocity of 300 mph (translational plus rotational velocities). The dynamic wind pressure is applied to the structures in the same manner as the wind loads described in subsection 3.3.1.2, except that the importance factor, gust factor, and the variation of wind speed with height do not apply. Loading combinations and load factors used are as follows:

$W_t = W_w$
$W_t = W_p$
$W_t = W_m$
$W_t = W_w + 0.5\ W_p$
$W_t = W_w + W_m$
$W_t = W_w + 0.5\ W_p + W_m$

where:

W_t = total tornado load
W_w = total wind load
W_p = total differential pressure load
W_m = total missile load

The maximum pressure drop of 2.0 psi, applicable to a nonvented structure, is used for W_p for all structures except the upper portion of the shield building. The portion of the shield building

surrounding the upper annulus is designed as fully vented (zero differential pressure) due to the large area of the air inlets and discharge stack. Figure 3.3-1 shows the velocity pressure variation with the radius from the center of the tornado. When the tornado loading includes the missile load, the structure locally may go into the plastic range because of missile impact. Subsection 3.5.3 discusses the procedure for analyzing local missile effects.

3.3.2.3 Effect of Failure of Structures or Components Not Designed for Tornado Loads

The failure of structures not designed for tornado loadings does not affect the capability of seismic Category I structures or safety-related systems performance. This is accomplished by one of the following:

- Designing the adjacent structure to seismic Category I structure tornado loading
- Investigating the effect of adjacent structure failure on seismic Category I structures to determine that no impairment of function results
- Designing a structural barrier to protect seismic Category I structures from adjacent structural failure.

The structures adjacent to the nuclear island are the annex building, the radwaste building, and the turbine building.

The portion of the annex building adjacent to the nuclear island is classified as seismic Category II and is designed to seismic Category I structure tornado loading. The acceptance criteria are based on ACI 349 for concrete structures and on AISC N690 for steel structures. The structure is constructed to the same requirements as nonseismic structures, ACI 318 for concrete structures, and AISC-S355 for steel structures. Siding is permitted to blow off during the tornado.

The radwaste building is a small steel-frame building. If it were to collapse in the tornado, it would not impair the integrity of the reinforced concrete nuclear island.

The turbine building is classified as nonseismic and is designed to seismic Category I structure tornado loading. The acceptance criteria are based on ACI 318 for concrete structures using a load factor of 1.0 and on 1.7 times the AISC S355 allowables for steel structures. Siding is permitted to blow off during the tornado.

3.3.2.4 Tornado Loads on the Passive Containment Cooling System Air Baffle

The containment air baffle is located within the annulus between the containment vessel and the shield building. It interfaces with the passive containment cooling system and separates downward flowing air entering at the air intake openings at the top of the cylindrical portion of the shield building from upward flowing air that cools the containment vessel and flows out of the discharge diffuser.

Loads due to the atmospheric pressure drop (W_p) are calculated assuming the tornado is centered over the containment. Differential pressure between the air intakes and the discharge is calculated

based on the radius of the shield building and the parameters of the tornado defined in subsection 3.3.2.1. The differential pressure is used with the pressure loss coefficients in the air flow path to determine pressures throughout the flow path.

The development of loads on the air baffle due to the design wind and tornado (W_w) are described in the test reports (References 3, 4, and 5). Models of the AP600 were tested in a wind tunnel and subjected to representative wind profiles. Pressures were measured on each side of the baffle, and the differential pressures were normalized to the input wind velocity. The pressure coefficients are applied to the effective dynamic pressure for the design wind and the tornado to obtain the wind loads across the baffle. The tornado wind is specified to be constant with height. The tornado loads calculated for the AP600 are applicable to the AP1000. The AP1000 configuration is similar to the AP600. The height of the shield building roof increases by 25’ 6"; the exterior diameter of the passive containment cooling storage tank increases from 80’ 0" to 89’ 0". The pressure coefficients measured in the AP600 tests are not significantly affected by these changes in geometry.

Wind conditions result in a pressure reduction in the annulus between the shield building and the containment vessel as well as above the containment dome. This reduced pressure is equivalent to an increase in containment internal pressure and is within the normal operating range for containment pressure (-0.2 to 1.0 psig).

Wind conditions result in a small wind load across the containment vessel. This is maximum opposite the air intakes where positive pressures occur on the windward side and negative pressures occur on the leeward side. Lateral loads on the containment vessel are developed in Reference 5.

3.3.3 Combined License Information

Combined License applicants referencing the AP1000 certified design will address site interface criteria for wind and tornado. The Combined License applicant will ensure that a tornado-initiated failure of structures and components within the Combined License applicant’s scope will not compromise the safety of AP1000 safety-related structures and components (see also subsection 3.5.4).

3.3.4 References

1. American Society of Civil Engineers, "Minimum Design Loads for Buildings and Other Structures," ASCE 7-98.

2. ASCE Paper No. 3269, "Wind Forces on Structures," Transactions of the American Society of Civil Engineers, Vol. 126, Part II (1961).

3. WCAP-13323-P and WCAP-13324-NP, "Phase II Wind Tunnel Testing for the Westinghouse AP600 Reactor," August 1992.

4. WCAP-14068-P, "Phase IVA Wind Tunnel Testing for the Westinghouse AP600 Reactor," May, 1994.

5. WCAP-14169-P, "Phase IVA Wind Tunnel Testing for the Westinghouse AP600 Reactor, Supplemental Report," September, 1994.

6. WCAP-13294-P and WCAP-13295-NP, "Phase I Wind Tunnel Testing for the Westinghouse AP600 Reactor," April 1992.

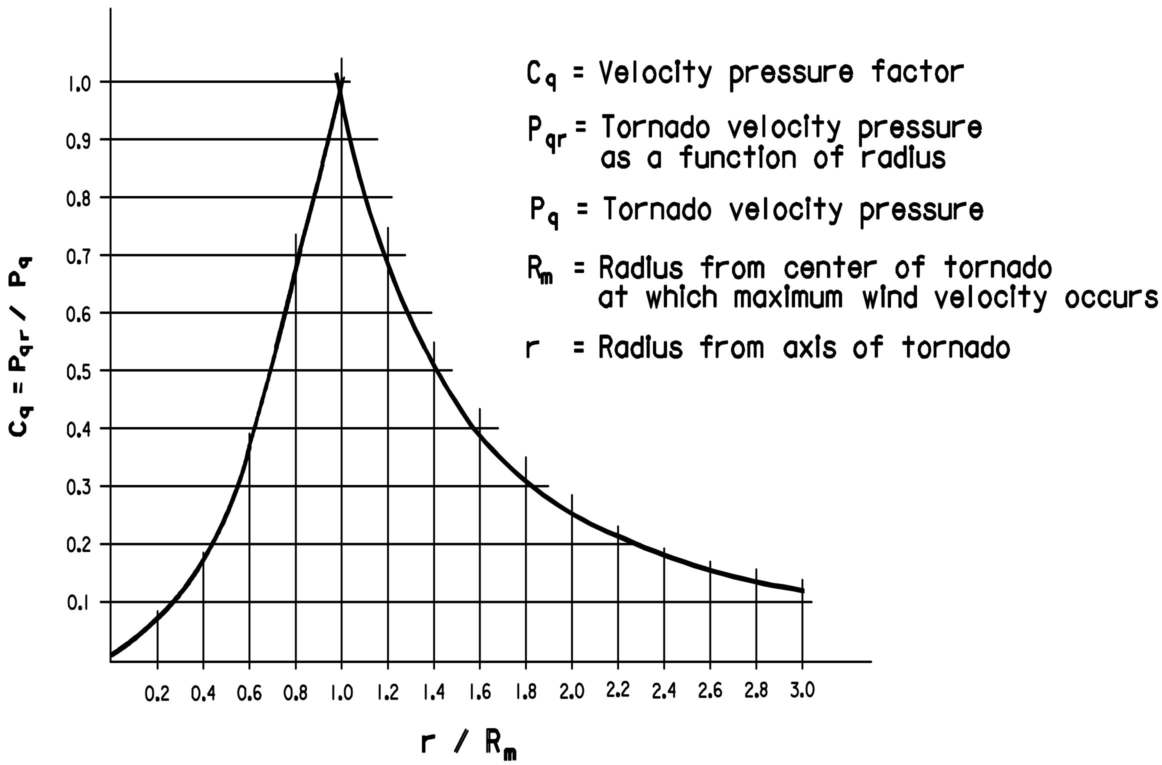


Figure 3.3-1

Velocity Pressure Variation with Radius from Center of Tornado

3.4 Water Level (Flood) Design

External flooding of a nuclear power plant from natural causes can be attributed to probable maximum flood, site and adjacent area probable maximum precipitation runoff, seiche, and ground water. Criteria for the design basis flood are in accordance with the provisions of Regulatory Guide 1.59, Design Basis Floods for Nuclear Power Plants, and Regulatory Guide 1.102, Flood Protection for Nuclear Power Plants. Conformance with the Regulatory Guides is described in Section 1.9. External events are described in the Combined License application. Chapter 2 provides interface data for AP1000 which has an interface flood level at plant grade.

Internal plant flooding can be attributed to piping ruptures, tank failures, or the actuation of fire suppression systems.

3.4.1 Flood Protection

3.4.1.1 Flood Protection Measures for Seismic Category I Structures, Systems, and Components

The seismic Category I structures, systems, and components identified in Section 3.2 are designed to withstand the effects of flooding due to natural phenomena or postulated component failures. A description of the structures is provided in subsections 3.8.2, 3.8.3, and 3.8.4. None of the nonsafety-related structures, systems and components were found to be important based on flooding considerations. As a result, nonsafety-related structures, systems and components are not important in mitigation of flood events and are not required to be protected from either internal or external flooding.

3.4.1.1.1 Protection from External Flooding

The probable maximum flood for the AP1000 has been established at less than plant elevation 100′ as discussed previously in Section 2.4. The probable maximum flood results from site specific events, such as river flooding, upstream dam failure, or other natural causes.

Flooding does not occur from the probable maximum precipitation. The roofs do not have drains or parapets. The roofs are sloped such that rainfall is directed towards gutters located along the edges of the roofs. Therefore, ponding of water on the roofs is precluded. Water from roof drains and/or scuppers, as well as runoff from the plant site and adjacent areas, is conveyed to catch basins, underground pipes, or directly to open ditches by sloping the tributary surface area. The site is graded to offer protection to the seismic Category I structures.

The high ground water table interface is at two feet below the grade elevation, as discussed in Section 2.4.

The components that may be potential sources for external flooding are nonsafety-related, nonseismic tanks as shown in DCD Figure 1.2-2:

- Fire water tanks as described in subsection 9.5.1. These two tanks have volumes of approximately 325,000 and 400,000 gallons, and are located at the north end of the turbine building.

- Condensate storage tank as described in subsection 9.2.4. This tank has a volume of approximately 485,000 gallons, and is located at the west side of the turbine building. Water will drain from the tank away from the turbine and auxiliary buildings due to site grading.

- Demineralized water tank as described in subsection 9.2.4. This tank has a volume of approximately 100,000 gallons and is located adjacent to the annex building at elevation 107′-2″. Water will drain from the tank away from the annex building to elevation 100′-0″. Nearby doors lead to areas in the annex building which do not contain safety-related components or systems.

- Boric acid storage tank as described in subsection 9.3.6. This tank has a volume of approximately 70,000 gallons and is located adjacent to the demineralized water storage tank.

- Diesel fuel oil tanks as described in subsection 9.5.4. These two tanks have volumes of approximately 100,000 gallons each. They are located remote from safety-related structures and are provided with dikes to retain leaks and spills.

- Passive containment cooling ancillary water storage tank as described in subsection 6.2.2.3. This tank has a volume of 780,000 gallons and is located at the west side of the auxiliary building. Water will drain from the tank away from the auxiliary building due to site grading.

In addition, failure of the cooling tower or the service water or circulating water piping under the yard could result in a potential flood source. However, these potential sources are located far from safety-related structures and the consequences of a failure in the yard would be enveloped by the analysis described in DCD subsection 10.4.5.

For the AP1000, the 100′-0″ building floor elevations are slightly above the grade elevation. In addition, the slope of the yard grade directs water away from the buildings. Because the probable maximum flood for AP1000 is less than grade elevation, the exterior doors are not required to be watertight for protection from external flooding.

The seismic Category I structures below grade are protected against flooding by a water barrier consisting of waterstops and a waterproofing system. The waterproofing system is provided by the introduction of a cementitious crystalline waterproofing additive to the nailed soil retention wall shotcrete or to the shotcrete applied to the rock surface as described in subsection 2.5.1. For the horizontal surface under the basemat, the cementitious crystalline waterproofing additive is added to the mud mat. The waterproofing additive is a unique chemical treatment added to the concrete at the time of batching and consists of portland cement, very fine silica sand, and various active proprietary chemicals. The active chemicals react with the moisture in fresh concrete, and the byproducts of cement hydration cause a catalytic reaction generating a nonsoluble crystalline formation of dendritic fibers throughout the pores and capillary tracts of the concrete. The concrete is thus sealed against penetration of water or liquid. Figure 3.4-1 shows the application of the water proofing additive.

Process piping penetrations and electrical raceway through the exterior walls of the nuclear island below grade are embedded in the wall or are welded to a steel sleeve embedded in the wall.

Process piping passing through the wall of the nuclear island below grade is located in a trench and localized pit adjacent to the wall of the auxiliary building. There are no access openings or tunnels penetrating the exterior walls of the nuclear island below grade.

The reinforced concrete seismic Category I structures, incorporating the waterproofing and sealing features described above, provide hardened protection for safety-related structures, systems, and components as defined in Regulatory Guide 1.59.

3.4.1.1.2 Protection from Internal Flooding

The nuclear island general arrangement drawings provided in Section 1.2 are a useful reference for the internal flooding discussion.

The AP1000 arrangement provides physical separation of redundant safety-related components and systems from each other and from nonsafety-related components. As a result, component failures resulting from internal flooding do not prevent safe shutdown of the plant or prevent mitigation of the flooding event. Protection mechanisms are described in Section 3.6. The protection mechanisms related to minimizing the consequences of internal flooding include the following:

- Structural enclosures
- Structural barriers
- Curbs and elevated thresholds
- Leak detection systems
- Drain systems

The AP1000 minimizes the number of penetrations through enclosure or barrier walls below the flood level. Those few penetrations through flood protection walls that are below the maximum flood level are watertight. Any process piping penetrating below the maximum flood level either is embedded in the wall or floor or is welded to a steel sleeve embedded in the wall or floor. There are no watertight doors in the AP1000 used for internal flood protection because, as described in subsection 3.4.1.2.2, they are not needed to protect safe shutdown components from the effects of internal flooding. The walls, floors, and penetrations are designed to withstand the maximum anticipated hydrodynamic loads associated with a pipe failure as described in Section 3.6.

3.4.1.2 Evaluation of Flooding Events

3.4.1.2.1 External Flooding

Base mat and exterior walls of seismic Category I structures are designed to resist upward and lateral pressures caused by the probable maximum flood and high ground water level. The vertical hydrostatic pressure acting uniformly at the bottom of the base mat is the product of the height to the high water level and the unit weight of water assumed as 62.4 lb/ft^3. The horizontal hydrostatic pressure acting on the exterior walls varies with height, with the maximum at the bottom of the wall and zero at the maximum water level. Minimum factors of safety for overturning, sliding, and flotation are described in subsection 3.8.5. There are no dynamic water forces associated with the probable maximum flood or high ground water level because they are below the finished grade.

Dynamic forces associated with the probable maximum precipitation are not factors in the analysis or design since the finished grade is adequately sloped.

There are no safety-related hydraulic structures for AP1000.

3.4.1.2.2 Internal Flooding

This section describes the consequences of compartment flooding for various postulated component failures. The equipment required to achieve and maintain safe shutdown depends on the initiating event. The safety-related systems and components available for safe shutdown are described in Section 7.4. This equipment is located in the auxiliary building and inside containment. Except for floor drains, no credit is taken in this evaluation for the availability of nonsafety-related systems or components.

Each area of the plant containing safety-related systems or equipment is reviewed to determine the postulated fluid system failures which would result in the most adverse internal flooding conditions. For the internal flooding analysis, the failure of safety-related systems, structures or components is acceptable provided they have no safe shutdown function or the safe shutdown function is otherwise accomplished. The internal flooding analysis shows that systems, structures, and components are not prevented from performing their required safe shutdown functions due to the effects of the postulated failure. In addition, the analysis identifies the protection features that mitigate the consequences of flooding in an area that contains safety-related equipment.

The flooding sources considered in the analysis consist of the following:

- High-energy piping (breaks and cracks)
- Through-wall cracks in seismically-supported moderate energy piping
- Breaks and through-wall cracks in non-seismically-supported moderate energy piping
- Pump mechanical seal failures
- Storage tank ruptures
- Actuation of fire suppression systems
- Flow from upper elevations and adjacent areas

The analysis is performed based on the criteria and assumptions provided in Section 3.6 and ANS-56.11 (Reference 1). Section 3.6 provides the criteria used to define break and crack locations and configurations for high and moderate-energy piping failures. Additional design criteria pertaining to the internal flooding analysis are provided in this section.

The analysis consists of the following steps:

- Identification of the flood sources
- Identification of essential equipment in area
- Determination of flow rates and flood levels
- Evaluation of effects on essential equipment

As stated in Section 3.6, high-energy ASME Code Class 1, 2, and 3 piping of 6 inch nominal diameter or larger inside the containment is evaluated for mechanistic pipe break (leak-before-break) for AP1000. Those high-energy piping systems that do not satisfy the mechanistic pipe break requirements inside containment and high-energy lines outside containment are evaluated for non-mechanistic breaks and cracks, as above.

Fluid flow rates from high- and moderate-energy piping ruptures are determined based on the criteria provided in Section 3.6 and ANSI 56.11 (Reference 1). Fluid flow rates through stairwells, floor openings, and floor sleeves are determined in accordance with the formulas given in Reference 1.

No breaks are assumed for piping with nominal diameters of 1 inch or less. For each storage tank rupture, it is assumed that the entire tank inventory is drained.

The analysis of potential flooding events is performed on a floor-by-floor and room-by-room basis depending upon the relative location of safety-related equipment. No credit is taken for operation of sump pumps to mitigate the consequences of flooding.

3.4.1.2.2.1 Containment Flooding Events

General

The safe shutdown systems and components located inside the containment are associated with the passive core cooling system (PXS), the automatic depressurization system (ADS), and containment isolation.

The evaluation of containment flooding events addresses the impact of flooding on the safe shutdown systems and components. The AP1000 passive core cooling system, the internal containment compartments, and the equipment locations are designed for internal flooding to maintain post accident long-term cooling flow to the reactor core from the flooded volumes.

In the unlikely event of a loss-of-coolant accident (LOCA), the combined water inventory from available sources within the containment is sufficient to flood the reactor and steam generator compartments to a level above the reactor coolant system piping to provide water flow back into the reactor coolant system via the break location or via the passive core cooling system containment recirculation subsystem (see DCD Section 6.3) flow path.

The potential for flooding safe shutdown components inside containment that would be required to perform safe shutdown functions is limited to two equipment compartments. These compartments are located in the southeast and northeast quadrants of the containment below the floor at elevation 107′-2″. For flood evaluation, these compartments extend up to the top of the curbs through the openings in the floor. These two compartments contain passive core cooling system components that provide two redundant means for delivering borated water to the reactor coolant system when required for safe shutdown.

The two passive core cooling system compartments primarily contain passive core cooling system components. The southeast compartment is referred to as the PXS-A compartment and the northeast compartment as the PXS-B compartment. The principal passive core cooling system

component in each passive core cooling system compartment is an accumulator. A passive core cooling system core makeup tank is located above each passive core cooling system compartment. Each passive core cooling system compartment also contains isolation valves for the accumulator, the core makeup tank, the in-containment refueling water storage tank, and the passive core cooling system containment recirculation subsystem line.

There are seven automatically actuated containment isolation valves inside containment subject to flooding. These normally closed containment isolation valves are not required to operate during a safe shutdown operation and they would not fail open as a result of the compartment flooding. Also, there is a redundant, normally closed, containment isolation valve located outside containment in series with each of these valves.

The PXS-A compartment contains one normally closed spent fuel pit cooling system containment isolation valve. The PXS-B compartment contains four normally closed normal residual heat removal system containment isolation valves. The maintenance floor contains two normally closed liquid radwaste system containment isolation valves located partially below the maximum flood level.

Except for the valves mentioned above, the rest of the automatically actuated containment isolation valves are located above the maximum flood level; therefore, these components would not be adversely affected by postulated flooding.

Flooding can be postulated from a failure of several systems located inside the containment. The worst case flooding scenario is a LOCA. The maximum flood level for a LOCA is based on the combined inventory of the reactor coolant system, the two accumulators, the two core makeup tanks, and the in-containment refueling water storage tank flooding the containment. The maximum inventory also considers makeup from the cask loading pit and boric acid tank.

Curbs are provided around openings through the maintenance floor at elevation 107′-2″ to control flooding. Overflow into the refueling canal occurs through a pipe centered at elevation 110′-0″. Curbs around openings into the chemical and volume control system compartment extend up to elevation 110′-0″. Curbs around openings into the PXS-A compartment extend up to elevation 110′-2″. Curbs around openings into the PXS-B compartment extend up to elevation 110′-1″. With these curb elevations, water flooding the maintenance floor is directed first into the refueling canal, then into the CVS compartment, then into the PXS-B compartment, and finally into the PXS-A compartment.

The evaluation of containment flooding from postulated component failures includes the compartments that are located below the maximum flood level. There are seven subcompartments that contain components below the floor at elevation 107′-2″. The active safe shutdown components inside containment which are located below the maximum flood level are located in only two of the seven floodable compartments.

The seven compartments partially or completely below the maximum flood level include the reactor vessel cavity, the two steam generator compartments, the vertical access tunnel, the two passive core cooling system compartments, and the chemical and volume control system compartment. The safe shutdown components are located in the two passive core cooling system compartments.

The reactor vessel cavity and the two steam generator compartments are interconnected by a large vertical access tunnel. These four compartments are treated, in this discussion, as one large floodable volume and they are referred to as the reactor coolant system compartment. Flooding of this compartment above elevation 107′-2″ also includes the maintenance floor outside the curbs around the other three compartments.

The PXS-A compartment (Room 11206), PXS-B compartment (Room 11207) and the chemical and volume control system compartment (Room 11208) are physically separated and isolated from each other by structural walls and curbs such that flooding in any one of these compartments or in the reactor coolant system compartment cannot cause flooding in any of the other compartments. The access hatch to the PXS-B compartment is located near the containment wall and is normally closed to address severe accident considerations. The access hatch to the PXS-B compartment is accessible from Room 11300 on elevation 107′-2″.

The fire protection system and the demineralized water transfer and storage system are open-cycle systems that enter the containment. During plant operation, the containment piping for these systems is isolated by containment isolation valves and is not a potential flooding source. These systems are not open systems as defined in Bulletin 80-24 (one that has an essentially unlimited source).

Reactor Coolant System Compartment

The reactor coolant system compartment, represented by the reactor vessel cavity, the two steam generator compartments, and the large vertical access tunnel, is the largest of the separate floodable compartments. With the exception of the pressurizer which is at a higher elevation, the principal components of the reactor coolant system are contained in this compartment.

The reactor vessel cavity and the adjoining equipment room are at the lowest level in the containment. The floor level of these rooms is at elevation 71′-6″ The floor level of the two steam generator compartments is at elevation 83′-0″.

The containment sump pumps are located in the equipment room at elevation 71′-6″. The arrangement for the floor drains from the two passive core cooling system compartments and the chemical and volume control system compartment provide a drain path for each compartment to the lowest level of containment (elevation 71′-6″) where the containment sump is located. Therefore, the source of the flooding in the reactor coolant system compartment is not limited to the components or systems contained within this compartment.

Any leakage that occurs within the containment drains by gravity to the elevation 71′-6″ equipment room. Reverse flow into the two passive core cooling system compartments and the chemical and volume control system compartment is prevented by redundant backflow preventers in each of the three compartment drain lines.

Flooding in any compartment of the containment is detected by the containment sump level monitoring system and the containment flood-up level instrumentation.

The containment sump level monitoring system consists of two seismically qualified level sensors in the containment sump. These sensors transmit the sump level indication to the main control room and the plant instrumentation system.

The plant instrumentation system monitors the rate of the sump level rise, calculates the leakage collection rate, and initiates the appropriate alarms in the main control room. A description of this leak detection system is provided in subsection 5.2.5.3.1.

Another indication of flooding in this compartment is provided by the containment flood-up level instrumentation consisting of two redundant Class 1E level sensor racks. Multiple discrete level signals are provided from the bottom of the reactor vessel cavity to the top of the vertical access tunnel. These level sensors transmit the containment sump water level indication to the main control room.

In the event that the source of the containment flooding can not be terminated, the water level in the reactor vessel cavity and the steam generator compartment continues to increase until the water source has been depleted or the leak has been isolated. The maximum level that could occur in the compartment from all of the water which is available in containment is elevation 108′-10″.

Since the reactor coolant system compartment contains no active safe shutdown components below the maximum flood-up level, the flooding of this compartment has no impact on safe shutdown capability.

Passive Core Cooling System Compartments

The PXS-A and PXS-B compartments, located in the southeast and northeast quadrants of the containment, primarily contain components associated with the passive core cooling system. The safe shutdown related components of the passive core cooling system located in these two compartments are redundant and essentially identical. One set of the redundant equipment is located in each of the two separate compartments.

The redundant passive core cooling system components located in these two compartments provide coolant to the reactor vessel from the two core makeup tanks, the two accumulators, and the in-containment refueling water storage tank via two independent and redundant direct vessel injection lines.

Each passive core cooling system compartment contains a parallel set of normally closed, air operated, core makeup tank isolation valves that receive actuation signals to open during a safe shutdown operation. These valves are approximately 10 feet above the floor level of the passive core cooling system compartments and 26 feet above the floor of the reactor vessel cavity.

Each passive core cooling system compartment also contains one normally open accumulator isolation valve and one normally open in-containment refueling water storage tank isolation valve. These valves do not have to be repositioned during a safe shutdown operation and a coincident flooding event.

In addition, each passive core cooling system compartment contains four passive core cooling system containment recirculation subsystem isolation valves. A normally closed, explosively

actuated valve is located in each of two parallel flow paths. One of the lines includes a check valve in series with the explosively-actuated valve. The other line includes a normally-closed, motor-operated valve in series with the explosively-actuated valve. The explosively-actuated and motor-operated valves are opened on a low in-containment refueling water storage tank level signal to provide a redundant flow path from the flooded reactor/steam generator compartments to the reactor vessel. One set of these redundant containment recirculation subsystem isolation valves is required to open to provide a redundant recirculation flow path to the reactor vessel. In the unlikely event that one of the two passive core cooling system compartments were to be flooded, the set of recirculation valves in the other, unflooded, compartment could be opened. Thus, a redundant, parallel flow path to the passive core cooling system containment recirculation subsystem is provided.

The design bases for this system are described in Section 6.3. The passive core cooling system is designed to perform its safety functions in the unlikely event of the most limiting single failure occurring coincident with any design basis event. For example, a direct vessel injection line could break in one of the two passive core cooling system compartments, thus preventing the core makeup tank and the accumulator located in the compartment from delivering borated water to the reactor vessel. A coincident single failure in the other passive core cooling system compartment would prevent only one of the two parallel injection paths from opening. This series of events would not prevent the passive core cooling system from performing its safety function.

The maximum flooding rate to either of these passive core cooling system compartments would occur on a postulated LOCA of one of the eight inch direct vessel injection lines at a location inside one of the two compartments. This postulated rupture would result in direct blowdown from the reactor coolant system to the compartment as well as blowdown of the associated core makeup tank and accumulator. The resulting flooding in one of two passive core cooling system compartments would not prevent the passive core cooling system from performing its safe shutdown function.

Another postulated LOCA, that would cause rapid flooding in the PXS-B compartment, is a rupture of the 12 inch normal residual heat removal system line. This line is routed from one of two reactor coolant system hot legs to a containment penetration in the PXS-B compartment.

The evaluation of containment flooding events is also concerned with non-LOCA flooding events. The maximum flooding rate to either of the passive core cooling system compartments, for a non-LOCA event, would be based on a postulated rupture of one of the two in-containment refueling water storage tank lines or a postulated rupture of one of the two accumulator injection lines.

A 10-inch line is routed from the in-containment refueling water storage tank to the PXS-A compartment and a 10-inch line is routed to the PXS-B compartment. The driving head from a full in-containment refueling water storage tank to either of these two compartments is approximately 35 feet. A rupture in one of these lines would result in flooding of the associated passive core cooling system compartment and the reactor coolant system compartment via the normal drain path or by overflowing the passive core cooling system compartment.

The 8-inch accumulator injection lines are routed from the accumulators to the 8-inch direct vessel injection lines. A rupture of either of these two injection lines at a point upstream of the two series reactor coolant system pressure boundary check valves would result in the blowdown of the accumulator to the associated compartment. The water level attained in this case would be limited to the water volume of the accumulator. The water level would not reach the level of the core makeup tank isolation valves.

The total flood-up of either the PXS-A or PXS-B compartments from any source of water is acceptable and does not prevent the passive core cooling system from performing its required safe shutdown function.

The PXS-A and the PXS-B compartments are physically separated and isolated from each other by a structural wall so that flooding in one compartment can not cause flooding in the other compartment. They are located below the maintenance floor level which is at elevation 107′-2″. A curb is provided around openings that penetrate through the maintenance floor into these compartments from the elevation 107′-2″ floor level.

There are several HVAC ducts, cable trays, and pipes that penetrate the maintenance floor into the passive core cooling system compartments. These penetrations are properly protected to prevent leakage into the passive core cooling system compartments.

The floor drains for these two compartments are located at elevation 84′-6″. Reverse flow through the floor drains is blocked by redundant, safety-related backflow preventers in the drain lines.

When the flooding rate exceeds the ability of the floor drain lines to drain the water from the compartment, or in the event that the floor drain line is blocked, the water level in that compartment increases to the entrance curb elevation.

Should the flooding continue, the water overflows from that compartment to the maintenance floor at elevation 107′-2″. The water overflowing to this level would immediately drain to the reactor coolant system compartment via the vertical access tunnel. There is no curb at the entrance to the vertical access tunnel; therefore, water on the maintenance floor (elevation 107′-2″) flows freely into the reactor coolant system compartment. For LOCA events, flooding via this path continues to a level above the reactor coolant system cold legs.

If the leakage rate into PXS-A or PXS-B were not excessive, the compartment drain lines would prevent significant flood-up in that compartment. Consequently, the flooding of the components could be prevented for postulated flooding events of limited duration and flowrates less than the drain line capacity.

The flow rate from the compartments is a function of the water height in the PXS compartments and the water height in the reactor coolant system compartment. The differential head between the two water levels establishes the flow rate from the compartment.

The draining of these compartments initiates flooding of the reactor vessel cavity and the adjoining cavity equipment room. If the operator does not terminate the leak, action is taken to shut down the reactor.

If the flooding rate is not greater than the compartment drain line capacity, the large volume of the reactor vessel cavity and the adjoining equipment room provides additional time for the operator to identify the source of leakage before any significant flooding occurs in the compartments containing the passive core cooling system equipment.

Should the flooding continue, the water level eventually reaches the steam generator compartment floor at elevation 83′-0″. The large floor area of the two steam generator compartments and the vertical access tunnel provides additional volume for flood-up and reduces the rate of level increase.

The containment isolation valves in these two passive core cooling system compartments are located above elevation 95′-0″, but below the maximum flood-up level. The PXS-A compartment contains one normally closed, motor operated, spent fuel pool cooling system containment isolation valve. The PXS-B compartment contains three normally closed, motor operated, normal residual heat removal system containment isolation valves. These containment isolation valves are not required to operate for safe shutdown and they do not fail open as a result of compartment flooding. Also, there are redundant outside containment isolation valves for each line that penetrates the containment boundary.

Chemical and Volume Control System Compartment

The majority of the components associated with the chemical and volume control system are located inside the containment in a separate compartment in the north quadrant of the containment below elevation 107′-2″.

There are several HVAC ducts, cable trays, and pipes that penetrate the maintenance floor into the chemical and volume control system compartment. These penetrations are properly protected to prevent leakage around the ducts into the chemical and volume control system compartment. The entrance curb elevation for the chemical and volume control system compartment is lower than the PXS-A and B compartment curbs to preferentially flood the chemical and volume control system compartment.

A single floor drain line is routed from this compartment to the containment sump at elevation 71′-6″. Reverse flow from the containment sump to this compartment is prevented by redundant, safety-related backflow preventers in the drain lines.

In the event that the single drain line were to be blocked, the water level in the chemical and volume control system compartment would flood to the level of the entrance curb elevation and would over flow to the maintenance floor at elevation 107′-2″. The water overflowing to this level would drain to the reactor coolant system compartment via the vertical access tunnel. There is no adverse effect on safe shutdown of the plant from flooding of the chemical and volume control system compartment.

The fire protection system and the demineralized water transfer and storage system are open-cycle systems that enter the containment. During plant operation, the containment piping for these systems is isolated by containment isolation valves and is not a potential flooding source. These systems are not open systems as defined in Bulletin 80-24 (one that has an essentially unlimited source).

3.4.1.2.2.2 Auxiliary Building Flooding Events

General

The AP1000 auxiliary building contains radiologically controlled areas and nonradiologically controlled areas which are physically separated by 2 and 3 foot structural walls and floor slabs. These structural barriers are designed to prevent flooding across the boundary between these areas by locating penetrations for piping and HVAC duct above maximum flood levels, or by sealing these penetrations. Process piping penetrations between the radiologically controlled areas and nonradiologically controlled areas are embedded in the wall or are welded to a steel sleeve in the wall. Electrical penetrations between the radiologically controlled areas and nonradiologically controlled areas are located above the maximum flood level. Electrical penetrations subject to the effects of the local build up of water on floors above the maximum flood level are also sealed.

For example, flooding in the auxiliary building at elevation 66′-6″ of the radiologically controlled area would not cause flooding in the nonradiologically controlled areas since the two areas are completely separated by a three foot thick structural wall. In the non-radiologically controlled area (non-RCA) of the auxiliary building, the four Class 1E electrical divisions are separated by 3-hour fire barriers. Portions of these fire barriers also serve as flood barriers.

- **Nonradiologically Controlled Areas**

  The safe shutdown systems and components that are located in the nonradiologically controlled area are associated with the protection and safety monitoring and Class 1E dc system, and containment isolation. The safe shutdown components associated with the protection and safety monitoring system are the instrumentation and control (I&C) cabinets located in the nonradioactive controlled area on level 3 (elevation 100′-0″). The safe shutdown components associated with the Class 1E dc system are the Class 1E batteries on level 1 (elevation 66′-6″) and level 2 (elevation 82′-6″) and dc electrical equipment also on level 2.

  The nonradiologically controlled areas of the auxiliary building are designed to provide maximum separation between the mechanical and electrical equipment areas. This separation prevents the propagation of leaks from the piping areas and the mechanical equipment areas to the Class 1E electrical and Class 1E I&C equipment rooms.

  The major piping compartments in the nonradiologically controlled area are the main steam isolation valve compartments on levels 4 and 5 (elevations 117′-6″ and 135′-3″, respectively) and the valve/piping penetration compartment on level 3 (elevation 100′-0″). The mechanical equipment rooms in the nonradiologically controlled area are the HVAC compartments on levels 4 and 5.

  Drain lines are provided in each of the piping and mechanical equipment compartments which drain to the turbine building drain tank. Leakage from postulated pipe ruptures in these compartments will drain to the turbine building.

- **Radiologically Controlled Areas**

  The safe shutdown components located in radiologically controlled areas (RCA) are primarily containment isolation valves which are located near the containment vessel and above elevation 82′-6″. These containment isolation valves are located above the maximum flood level for this area. They are required to either close or remain closed during a safe shutdown operation.

The evaluation of potential flooding within the radiologically and nonradiologically controlled areas of the auxiliary building is performed on a floor-by-floor basis as described below.

Auxiliary Building Level 1 (Elevation 66′-6″)

- **Nonradiologically Controlled Area**

  Level 1 of the nonradiologically controlled area has five individual rooms that contain Class 1E batteries: four divisional (A, B, C, and D) Class 1E battery rooms and one Class 1E spare battery room. The doors are not water tight.

  The primary line of defense for level 1 is to exclude fluid systems and their associated piping from this area. The only fluid systems in level 1 are the potable water and fire protection systems. Potable water is used for battery washdown and the emergency eye wash/shower facilities. The maximum nominal diameter of potable water piping in this area is 1 inch; therefore, it is excluded from consideration as a source of flooding.

  The potential for flooding on level 1 is limited to fire fighting activities. The seismically qualified fire protection system piping routed through levels 1, 2, 3, and 4 is the only piping in this area that is greater than 1 inch in diameter.

  Fire fighting activities in levels 1, 2, 3, or 4 would contribute to flooding in level 1. The drain lines, stairwells, and the elevator shaft direct the water from fire fighting activities down to the auxiliary building nonradiologically controlled area sump located on level 1.

  Fire fighting in these five battery rooms is accomplished by manual means from two fire hose stations located adjacent to the two stairwells. The maximum flowrate to this area from the two hose stations is assumed to be 250 gpm.

  A limited supply of water is initially provided to the fire protection system standpipe fire hose stations (See subsection 9.5.1) from the passive containment cooling system storage tank. A nominal volume of 18,000 gallons is provided for the fire protection system. A volume of 42,000 gallons is conservatively assumed; this is the volume in the tank between the elevations of the fire protection system inlet and the tank overflow. In the event that both fire hose stations are used to fight a fire in one of the five battery rooms, the maximum water depth would be less than 12 inches, assuming that the water could propagate into all rooms on this level. This maximum water depth is substantially below the terminal height on the first row of batteries which is located approximately 30 inches above the floor.

Since a limited supply of fire water is provided, inadvertent initiation of the fire protection system can not exceed the flooding levels described above. Operator action to stop inadvertent water flow from the fire protection system is expected to limit flooding to only a small fraction of this water supply.

Structural walls, drain line routing, and raised platforms prevent leakage that may occur in piping or mechanical areas on levels 4 and 5 from propagating to the electrical areas on levels 1, 2, 3, or 4.

Dual sump pumps and water level sensors are also provided in the sump on level 1. The level sensors transmit water level indication to the main control room and the plant control system. Level alarms alert the operator to take corrective action.

The sump pumps are sized to remove approximately 250 gpm (with two pumps operating) based on a maximum flow from two fire hose stations of 250 gpm. The discharge of these pumps is directed to the turbine building drain tank of the waste water system (WWS) located on elevation 89′-0″ of the turbine building as described in subsection 9.2.9. The discharge line into the tank is provided with a standpipe to prevent siphoning back to the auxiliary building nonradiologically controlled area sump. These sump pumps and level sensors are not required to maintain safe shutdown capability.

- **Radiologically Controlled Area**

There are no safe shutdown components located on level 1 of the radiologically controlled area. The radiologically controlled area of the auxiliary building is subject to flooding from a variety of potential sources including the component cooling water, central chilled water, hot water, spent fuel pool cooling, normal residual heat removal system, and chemical and volume control system, as well as various tanks. Most of the piping associated with these systems is above level 1; however, the flow from any postulated rupture in the radiologically controlled area will eventually flood level 1. The principal flow paths to level 1 are the vertical pipe chase and the floor gratings provided in the elevator lobbies on levels 2 and 3. Other flow paths include the floor drain system, the stairwell, and the elevator shaft.

The auxiliary building radiologically controlled area sump is located on level 1 with dual sump pumps and water level sensor provided in the sump. The level sensor transmits water level indication to the main control room and the plant control system. High level alarms alert the operator to take corrective action.

The sump pumps are sized to remove approximately 250 gpm (with two pumps operating) based on a maximum flow from two fire hose stations of 250 gpm. The discharge of these pumps is directed to the waste holdup tanks of the liquid radioactive waste system as described in subsection 11.2. These sump pumps and level sensor are not required to maintain safe shutdown capability.

For the component cooling water and central chilled water systems, the maximum flooding volume is bounded by the system volume plus a reasonable period of makeup. For the spent fuel pool cooling system, the maximum flooding volume is limited to the volume of water above the spent fuel pool strainer plus a reasonable period of makeup. This flooding volume

is approximately equal to that of the component cooling water and chilled water systems above.

The normal residual heat removal system is operated only when the plant is shutdown. Since it is not normally operating, it is evaluated as a moderate-energy system. Flooding is determined based on the maximum flowrate from a through-wall crack in a 8 inch normal residual heat removal system discharge line. Assuming that the leakage is detected and isolated within 30 minutes after initiation, the maximum flooding volume is approximately equal to those above.

Flooding due to a break in the high-energy chemical and volume control system makeup pump discharge line is bounded by the normal residual heat removal system through-wall crack.

Flow from the postulated break spreads throughout the level 1 rooms and corridor via flow under doors and interconnecting floor drains if the auxiliary building radiologically controlled area sump pumps are inoperable. The maximum flood level in the area, for any of the cases above, is less than 12 inches. This flooding has no impact on safe shutdown since there are no components on level 1 required for safe shutdown.

Normal residual heat removal systems components with systems important missions are expected to remain functional following the flooding event since the pump motors and valve operators are above the maximum flood level if the flood source is not a break in the normal residual heat removal system piping itself.

Flow from a tank rupture in one of the tank rooms will initially flood the tank room, and begin to flow to the auxiliary building radiologically controlled area sump via floor drains. If the sump pumps are inoperable, the tank volume floods the balance of level 1 via the interconnecting floor drains. The maximum flood level for this event is less than for the piping failures discussed above.

Auxiliary Building Level 2 (Elevation 82′-6″)

- **Nonradiologically Controlled Area**

  Level 2 of the nonradiologically controlled area has two Class 1E battery rooms, four divisional Class 1E dc electrical equipment rooms, and one Class 1E reactor coolant pump trip switchgear room. The doors to these rooms are not water tight.

  Level 2 contains an arrangement of fire protection and potable water piping similar to level 1.

  The potential for flooding on this level is limited to fire fighting activities. Fire fighting in these rooms is accomplished by manual means from two fire hose stations located adjacent to the two stairwells. The maximum flowrate to this area from the two hose stations is assumed to be 250 gpm.

The drains, elevator shafts, and stairwells drain water spilled on this level to level 1. Therefore, no significant accumulation of water occurs on level 2.

- **Radiologically Controlled Area**

The radiologically controlled area on level 2 contains a few containment isolation valves. The horizontal pipe chase at elevation 92′-6″ contains two normally closed normal residual heat removal system isolation valves. One spent fuel pool cooling system containment isolation valve is located, above 92′-6″, in the adjacent vertical pipe chase. The area on the north side of the lower annulus contains two chemical and volume control system and two liquid radwaste automatically operated containment isolation valves above elevation 82′-6″. These valves are required to close or remain closed during a safe shutdown operation.

Two chemical and volume control system valves used to isolate the chemical and volume control system makeup pump suction from the demineralized water storage tank are located in the makeup pump compartment at 82′-6″. These safety-related valves close or remain closed to prevent boron dilution events. They are not required for safe shutdown.

Potential sources of flooding for this area include the chemical and volume control system and the fire protection system, including an automatic suppression system in the CVS makeup pump room. Flow from a component rupture or from fire fighting activities on level 2 drains to level 1 as described below.

To protect the above valves from flooding, the makeup pump compartment at elevation 82′-6″ drains, via the floor grating located in the corridor adjacent to the stairwell, directly to elevation 66′-6″. Flooding in the lower annulus drains directly to elevation 66′-6″ via the floor grating and various openings to the tank rooms. The stairwell and elevator shaft on the east wall are additional flow paths to level 1. The horizontal pipe chase at elevation 92′-6″ drains under the door directly to elevation 66′-6″ via the vertical pipe chase. As a result of these drain paths, there is no significant accumulation of water in the makeup pump compartment, lower annulus or the horizontal pipe chase from any postulated pipe ruptures. The containment isolation valves are above the maximum flood level in these areas. The chemical and volume control system makeup pumps and the normal residual heat removal valves in the valve compartment are nonsafety-related defense-in-depth equipment and are expected to remain functional following the flooding event since the pump motors and valve operators are above the calculated flood level of 6 inches.

Auxiliary Building Level 3 (Elevation 100′-0″)

- **Nonradiologically Controlled Area**

Level 3 of the nonradiologically controlled area includes the remote shutdown room, one reactor coolant pump trip switchgear room, four divisional Class 1E I&C rooms, one equipment room, and the valve/piping penetration room. The division A, B, C and D I&C rooms and the electrical room also include containment electrical penetrations. The doors are not water tight.

The level 3 Class 1E and non-Class 1E electrical areas contain only fire protection system piping. Fire hose stations are provided near each of the two stairwells and normally dry fire protection piping, supplied from the passive containment system tank, serves the preaction sprinkler system in the non-1E equipment/penetration room. The potential for flooding in the electrical areas on this level is limited to fire fighting activities. The maximum flowrate to this area from either automatic or manual fire fighting activities is assumed to be 250 gpm. The floor drains, stairwells, and elevator shaft drain water spilled on this level down to level 1. Therefore, no significant accumulation of water occurs in this area.

The valve/piping penetration room on level 3 is physically separated from the electrical rooms. The valve/piping penetration room contains automatically actuated containment isolation valves for the steam generator blowdown system and the hydrogen line in the chemical and volume control system. Access to this room is from the turbine building. The access door and drain lines provided in this room drain from the auxiliary building to the turbine building. Maximum postulated flood level for this room is less than 36 inches. The containment isolation valves in the area are located above this maximum flood level.

- **Radiologically Controlled Area**

  There are no safe shutdown components located on level 3.

  Potential sources of flooding for this area include the normal residual heat removal system, the component cooling water system, the effluent monitor tanks and the fire protection system, including an automatic suppression system in the rail car bay. Flow from a component rupture or from fire fighting activities on level 3 drains directly to level 1.

Auxiliary Building Level 4 (Elevation 117′-6″)

- **Nonradiologically Controlled Area**

  Level 4 of the nonradiologically controlled area includes the main control room, one divisional Class 1E penetration room, one non-Class 1E electrical penetration room, two main steam isolation valve compartments, and one mechanical equipment room.

  The doors to these rooms are not water tight. There are no doors from the main steam isolation valve compartments to the Class 1E electrical areas. The main steam isolation valve compartments are only accessible from the turbine building at elevation 135′-3″. The mechanical equipment room is only accessible from the turbine building at elevation 117′-6″.

  The potential for flooding Class 1E electrical areas on this level is limited to fire fighting activities. The Class 1E electrical penetration room and main control room are accessible from a hose station near the east stairwell. While the main control room kitchen and restroom are provided with potable water, the lines are 1 inch and smaller, and are not evaluated for pipe ruptures.

  Fire fighting in the control room is done manually using portable extinguishers or a fire hose from a hose station in the east corridor. In the event that a hose is brought into the main control room through the east corridor access doors, water accumulation is limited by flow

through the access doors which are open. The threshold of the east corridor access door is at the elevation of the floor slab. Once in the corridor this flow drains, via floor drains, the stairwell and elevator shaft, to level 1. An emergency egress door and stairwell is located on the west end of the main control room, which leads down to the remote shutdown room. The threshold of the emergency egress door is flush with the raised portion of flooring in the main control room, which is approximately 14 inches above the east corridor entrance. Water being discharged in this area will flow through the porous raised flooring and flow back out the east access doors. The main control room has a normally closed floor drain which can be manually opened to drain water to the auxiliary building non-RCA sump at level 1. The drain paths prevent significant flooding of the adjacent rooms.

In the event of fire fighting activity in the non-Class 1E electrical penetration rooms, the accumulation of water is prevented by floor drains and flows through the stairwell and elevator shaft to level 1.

The mechanical equipment room contains containment isolation valves for the chilled water, compressed air, component cooling water, and passive core cooling (nitrogen) systems. Flooding in the mechanical equipment room due to fire fighting or piping ruptures is directed to the turbine building through the access door at elevation 117′-6″ or through floor drains to the turbine building. The maximum flood level for this room is 4 inches. The containment isolation valves in this area are located above this maximum flood level.

The main steam isolation valve compartments contain the main steam and main feedwater piping and their isolation valves. In the event of a pipe break or leak in the area, floor drains to the turbine building are provided. Structural walls and floors are designed to prevent flow of water to levels 1, 2, or 3. For larger flows, wall openings and pressure relief panels, located at floor elevation, open to drain the rooms to the turbine building. The maximum flood level for these rooms is less than 36 inches. The isolation valves in this area are located above this maximum flood level.

- **Radiologically Controlled Area**

In the radiologically controlled area, there are six containment isolation valves on level 4. Five of these are located in the vertical pipe chase. These are for the primary sampling system, spent fuel pool cooling system and containment air filtration system. The primary source of flooding in the vertical pipe chase is the spent fuel cooling line. Flow from this break will be directed through grating down to level 3 where water will flow under the door to the staging area and through floor drains to the auxiliary building RCA sump which limits the flood level to less than 7 inches. The containment isolation valves are located above the spent fuel cooling line and there are no other sources of flooding located above them. The other containment isolation valve for the containment air filtration system is located in a separate compartment adjacent to column line 5. The principal source of flooding for this area is fire fighting from a hose station located at elevation 107′-2″. Flow from this source will be directed under the door and through floor drains to the auxiliary building radiologically controlled area sump which limits the flood level to less than 3 inches. No other safe shutdown equipment is located in this area.

Auxiliary Building Level 5 (Elevation 135′-3″)

- **Nonradiologically Controlled Area**

  Level 5 of the nonradiologically controlled area contains two mechanical HVAC equipment rooms and the upper portion of the two main steam isolation valve compartments. There is no safety-related equipment on level 5.

  The evaluation of the main steam isolation valve compartments is addressed in the discussion of level 4.

  Water from fire fighting, postulated pipe or potable water storage tank (150 gallons) ruptures in the main mechanical HVAC equipment rooms drains to the turbine building via floor drains or to the annex building via flow under the doors. Therefore, no significant accumulation of water occurs in this room. Floor penetrations are sealed and a 6 inch platform is provided at the elevator and stairwell such that flooding in these rooms does not propagate to levels below.

  The mechanical room between the main steam isolation valve compartments at level 5 is accessed from the turbine building on the same level. This room is drained to the turbine building. In the event of fire fighting or postulated pipe ruptures, the accumulation of water is prevented by directing the flow to the drains or under the doors into the turbine building. Floor penetrations are sealed such that flooding in this area does not propagate to other areas of the auxiliary building.

- **Radiologically Controlled Area**

  Level 5 of the radiologically controlled area contains the fuel handling area operating deck, HVAC equipment and access rooms, the main equipment hatch staging area, and the component cooling water system valve room. The only safety-related equipment on level 5 are the compressed air tanks for the main control room emergency habitability system located in the main equipment hatch staging area.

  Over-filling of the spent fuel pool would flood the fuel handling area operating deck. The flooding flow rate is limited by the makeup capacity from the demineralized water or chemical and volume control systems. Accumulation of water in this area is prevented by floor drains and by flow to the stairwells and elevator shaft which drain to level 1. Spent fuel pool cooling is not adversely affected by this event. There is no safe shutdown equipment in this area. The component cooling water system valves with the regulatory treatment of nonsafety-related system important missions located in the component cooling water system valve room which support the normal residual heat removal system, are located well above the maximum flood level for this area and are expected to remain functional in a flooding event.

  The shield building stairwell serves as a pipe chase for passive containment cooling system supply and return lines, drains for the passive containment cooling system valve room and passive containment cooling system air outlet shield plug, and a fire water line. Leakage from a crack in one of these lines flows down the stairwell to level 5, under the stairwell door to

the HVAC equipment room, and then to the auxiliary building radiologically controlled area sump via floor drains or to the annex building. There is no significant accumulation in the stairwell or the equipment and access rooms. There is no safe shutdown equipment in this area. The passive containment cooling system supply and return line connections to the passive containment cooling system storage tank are above the minimum water level, thus a leak in these lines would not adversely affect the safe shutdown capability of the passive containment cooling system.

Water from fire fighting in the main equipment hatch staging area drains to the auxiliary building radiologically controlled area sump via floor drains, or to the annex building via flow under the roll-up door. Therefore, no significant accumulation of water occurs in this area.

Auxiliary Building Upper Annulus (Elevation 132′-3″)

This area serves as the air flow path for the passive containment cooling system. It is bounded by the seismic Category I shield building on the outside and the seismic Category I containment vessel on the inside. The floor has a curb on the outside with a flexible seal connected to the shield building. The curb and seal block communication with the middle annulus area, below. The outside wall of the annulus is provided with redundant safety-related drains to the yard drainage system.

The worst case flooding scenario is postulated as blockage of the nonsafety-related floor drains concurrent with inadvertent opening of a passive containment cooling system cooling water isolation valve. The maximum flood level is determined by the flow gradient to the operating drains. Maximum level will be approximately 2 feet. This level does not affect the capability of passive containment cooling system air cooling. No other safe shutdown equipment is affected. Passive containment cooling system operation or leakage is detected by sensors on the passive containment cooling system discharge line. During non-accident conditions the annulus is accessible to manually clear any drain blockage.

PCS Valve Room (Elevation 286′-6″)

This room contains three redundant safety-related valve trains for the passive containment cooling system water cooling subsystem. One train must open to provide the required containment cooling. The only source of flooding for this room is a through-wall crack in the passive containment cooling system piping. The worst crack location is in the 6 inch line between the valves and the flow control orifices. This leak is not isolable from the 800,000 gallon passive containment cooling system water storage tank above the valve room. Flow is by gravity.

Leakage will flow down to the landing at elevation 264′-6″ where the water will flow through floor drains or under doors to the upper annulus which is then discharged through redundant drains to the storm drain. There will be negligible water accumulation in the valve room. The passive containment cooling system isolation valves are located above the maximum flood level in the valve room, so they remain operable.

Sensors in the valve room drain sump are provided for leak detection. An alarm is provided in the main control room to alert the operator to take corrective action if the level sensors detect an

abnormal water level in the valve room. The leakage does not adversely affect containment or any other essential system.

3.4.1.2.2.3 Adjacent Structures Flooding Events

Turbine Building

The turbine building is subject to flooding from a variety of potential sources including the circulating water, service water, condensate/feedwater, component cooling water, turbine building cooling water, demineralized water and fire protection systems as well as the deaerator storage tank. Flow from any postulated ruptures above elevation 100′-0″ flows down to elevation 100′-0″ via floor grating and stairwells. Thus, there will be a negligible contribution from these sources to flooding of the auxiliary building compartments at elevations 135′-3″ and 117′-6″ via flow under doors. Auxiliary building flooding is bounded by the effects of postulated breaks in the compartments.

The bounding flooding source for the turbine building is a break in the circulating water piping which would result in flooding of the elevation 100′-0″ floor. Flow from this break runs out of the building to the yard through a relief panel in the turbine building west wall and limits the maximum flood level to less than 6 inches. The only area of the auxiliary building which interfaces with the turbine building at elevation 100′-0″ is the valve/piping penetration room. This room could be flooded via flow under the door or backflow through the drains, however the flood level would be less than postulated for a break in the valve/piping penetration room itself.

The waste water system (WWS) sump pumps located in the nonradiologically controlled area of the auxiliary building discharge to the turbine building drain tank. Backflow from the drain tank is prevented as described in subsection 3.4.1.2.2.2.

There is no safety-related equipment in the turbine building. The component cooling water and service water components on elevation 100′-0″ which provide the regulatory treatment of nonsafety-related systems important support for the normal residual heat removal system, are expected to remain functional following a flooding event in the turbine building since the pump motors and valve operators are above the expected flood level.

Annex Building

- **Nonradiologically Controlled Areas**

  The primary sources of flooding in the nonradiologically controlled areas of the annex building are the component cooling water, chilled water and fire protection systems. Water from postulated breaks above elevation 100′-0″ flows primarily through floor drains to the annex building sump that discharges to the turbine building drain tank. Alternate paths include flows to the turbine building via flow under access doors at elevations 135′-3″ and 117′-6″ and flows down to elevation 100′-0″ via stairwells and elevator shaft. Water accumulation at elevation 100′-0″ is minimized by floor drains to the annex building sump and by flow under the access doors to the turbine building or the doors leading directly to the yard area. The floors of the annex building are sloped away from the access doors to the

nuclear island in the vicinity of the access doors to prevent migration of flood water to the nonradiologically controlled areas of the nuclear island.

There is no safety-related equipment in the nonradiologically controlled area portion of the annex building. The main ac power system components with regulatory treatment of nonsafety-related systems important missions are located on elevation 117′-6″ in the electrical switchgear rooms, which are separated from potential flood sources. Water from manual fire fighting operations is collected by floor drains discharging to the annex building sump or down a hatch or stairwell to elevation 100′-0″. The non-Class 1E dc and UPS system (EDS) equipment with regulatory treatment of nonsafety-related systems important missions is located on elevation 100′-0″ in separate battery rooms. Water in one of these rooms due to manual fire fighting in the room is collected by floor drains to the annex building sump or flows to the turbine building under doors or to the yard area through doors. This is not expected to affect functionality of equipment in the adjacent rooms.

- **Radiologically Controlled Areas**

  There is no safety-related equipment in the radiologically controlled area portion of the annex building. The primary sources of flooding in the radiologically controlled areas of the annex building are the component cooling water, chilled water and fire protection systems, including an automatic suppression system that protects the containment access corridor. Water from postulated breaks above elevation 100′-0″ drains through floor drains to the radioactive waste drain system sump in the radiologically controlled area of the auxiliary building or drains to elevation 100′-0″ via stairwells and equipment handling hatches or under access doors to the radiologically controlled area portion of the auxiliary building. Accumulated water at elevation 100′-0″ is minimized by floor drains discharging to the radioactive waste drain system sump or chemical waste tank in the auxiliary building. The contribution of water to the flooding of the radiologically controlled area portion of the auxiliary building is bounded by flooding events which could occur in the auxiliary building.

Radwaste Building

The potential sources of flooding in the radwaste building are the chilled water, hot water, and fire protection systems. Flow from postulated breaks is directed to floor drains via a curb/sloped floor around the perimeter to drain to the radioactive waste drain system sump in the radiologically controlled area of auxiliary building. The contribution of water to flooding of the auxiliary building is bounded by flooding events which could occur in the auxiliary building. There are no safety-related systems or components or equipment with regulatory treatment of nonsafety-related systems important missions in the radwaste building.

Diesel Generator Building

The potential source of flooding in the diesel generator building is the fire protection system. There is no safety-related equipment in the diesel generator building. The diesel generator system which has regulatory treatment of nonsafety-related systems important mission has each diesel and associated auxiliaries in a separate compartment. Flooding due to a break in a fire water header is directed to the respective diesel generator building sump and subsequently pumped to the turbine

building drain tank or is drained by gravity to the yard area under the access doors. The equipment in the adjacent diesel generator compartment should remain functional following the event.

3.4.1.3 Permanent Dewatering System

The need for a permanent dewatering system is site specific and is defined by the Combined License applicant.

3.4.2 Analytical and Test Procedures

The AP1000 is designed so that the maximum water levels considered due to natural phenomena or internal flooding do not jeopardize the safety of the plant or the ability to achieve and maintain safe shutdown conditions. The analytical approach in the consideration of external and internal flooding events is described in subsection 3.4.1.2.

3.4.3 Combined License Information

The Combined License applicant will demonstrate that the site satisfies the interface requirements as described in Section 2.4. If these criteria cannot be satisfied because of site-specific flooding hazards, the Combined License applicant may propose protective measures as discussed in Section 2.4.

3.4.4 References

1. ANSI/ANS-56.11-1988, "Design Criteria for Protection against the Effects of Compartment Flooding in Light Water Reactor Plants."

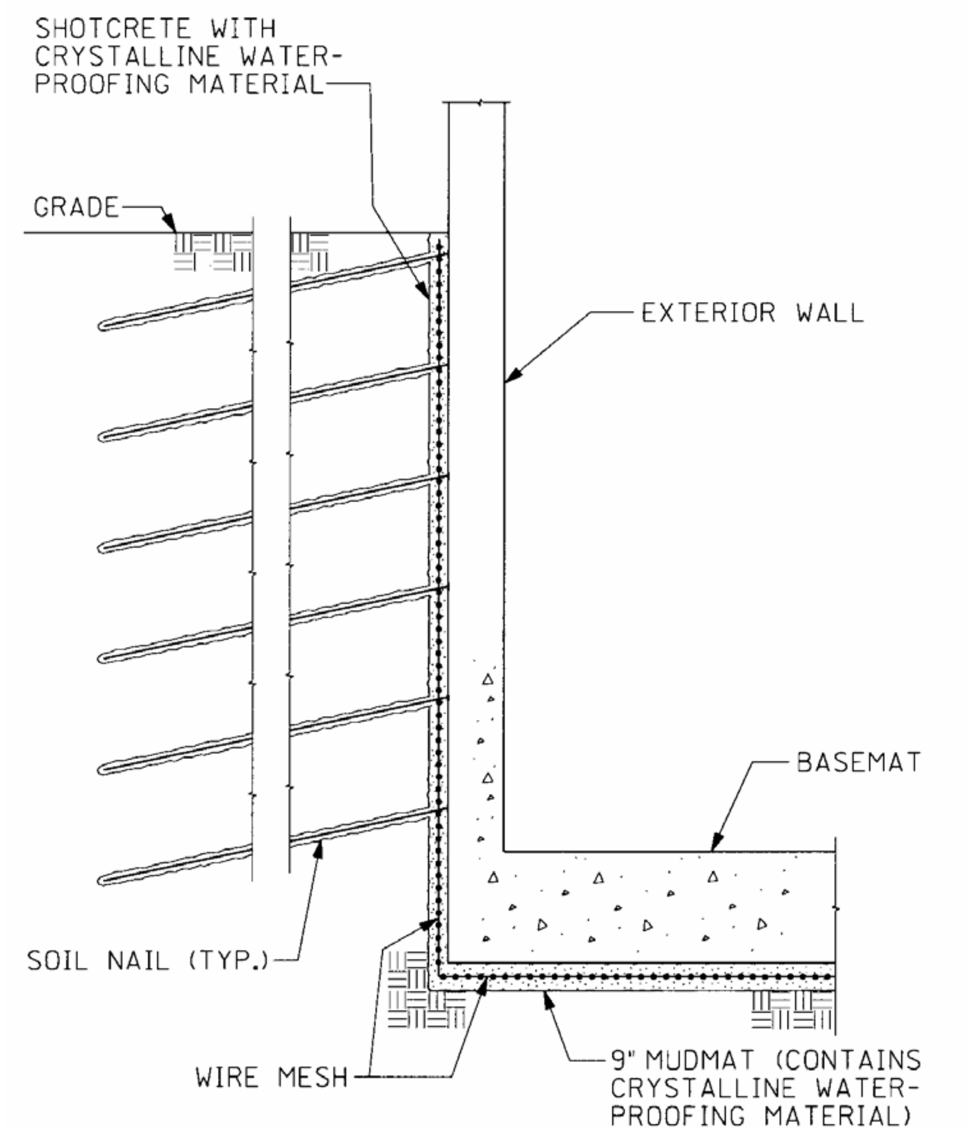


Figure 3.4-1

Nuclear Island Waterproofing Below Grade

3.5 Missile Protection

General Design Criterion 4 of Appendix A to 10 CFR 50 requires that structures systems and components important to safety be protected from the effects of missiles. The AP1000 criteria for protection from postulated missiles provide the capability to safely shut down the reactor and maintain it in a safe shutdown condition. The AP1000 criteria also protect the integrity of the reactor coolant system pressure boundary and maintain offsite radiological dose/concentration levels within the limits defined in 10 CFR 100.

Missiles may be generated by pressurized components, rotating machinery, and explosions within the plant and by tornadoes or transportation accidents external to the plant. Potential missile hazards are eliminated to the extent practical by minimizing the potential sources of missiles through proper selection of equipment, and by arrangement of structures and equipment in a manner to minimize the potential for damage from missiles. Potential missiles due to failures of nonseismic items are addressed in subsection 3.7.3.13. Heavy load-drop evaluations are described in subsection 9.1.5.

The following are definitions for missile protection terminology:

Internally Generated Missile – A mass that may be accelerated by energy sources continuously present on site.

Single Active Failure – Malfunction or loss of a component of electrical or fluid systems. The failure of an active component of a fluid system is considered to be a loss of component function as a result of mechanical, hydraulic, pneumatic, or electrical malfunction, but not the loss of component structural integrity.

High-Energy System – Fluid systems that, during normal plant conditions, are operated or maintained pressurized with a maximum operating temperature greater than 200°F and/or a maximum operating pressure greater than 275 psig, as discussed in subsection 3.6.1.

The following criteria are applied in the identification of missiles and the protection requirements that must be satisfied:

- A missile must not damage structures, systems, or components to the extent that could prevent achieving or maintaining safe shutdown of the plant or result in a significant release of radioactivity.

- A single active component failure is assumed in systems used to mitigate the consequences of the postulated missile and achieve a safe shutdown condition. The single active component failure is assumed to occur in addition to the postulated missile and any direct consequences of the missile. When the postulated missile is generated in one of two or more redundant trains of a dual-purpose safety-related fluid system, which is designed to seismic Category I standards and is capable of being powered from both onsite and offsite sources, a single active component failure need not be assumed in the remaining train(s), or associated supporting trains.

- Walls, partitions, and other items that enclose safety-related systems, or separate redundant trains of safety related equipment, must be constructed so that a postulated missile cannot damage components required to achieve safe shutdown nor damage components required to prevent a release of radioactivity producing offsite doses in excess of 10 CFR 100 limits.

- A postulated missile from the reactor coolant system must not cause loss of integrity of the primary containment, main steam, feedwater, or other loop of the reactor coolant system.

- A postulated missile from any system other than the reactor coolant system must not cause loss of integrity of the containment or the reactor coolant system pressure boundary.

- Other plant accidents or severe natural phenomena are not assumed to occur in conjunction with a postulated missile (except for tornado).

- Offsite power is assumed to be unavailable if a trip of the turbine-generator or reactor protection system is a direct consequence of the postulated missile.

- Safe shutdown is accomplished using only safety-related systems with a coincident single active failure, although nonsafety-related systems not affected by the missile are available to support safe shutdown.

- Missiles are postulated to occur where the single failure of a retention mechanism can result in a missile, unless the missile is not considered credible as discussed later. Missiles created by the independent failures of two retention mechanisms are not postulated.

- The energy of postulated missiles produced by rotating components is based on a 120 percent overspeed condition, unless such an overspeed condition is not possible (such as a synchronous motor).

- Equipment required for safe shutdown is located in plant areas separate from potential missile sources wherever practical.

- Spatial separation may be used to demonstrate protection from missile hazards when it is shown that the range and trajectory of the generated missile is less than the distance to or is directed away from the potential target.

The AP1000 passive design minimizes the number of safety-related structures, systems, and components required for safe shutdown. Systems required for safe shutdown are identified in Chapter 7. Safety class structures, systems and components, their location, seismic category, and quality group classifications are given in Section 3.2. General arrangement drawings showing locations of the structures, systems, and components are given in Section 1.2. The areas required for safe shutdown, and the major systems and components housed therein that are required to be protected from internally and externally generated missiles for safe shutdown, are summarized below:

- The containment vessel, including the reactor coolant loop, and passive core cooling system inside containment

- The shield building, including the passive containment cooling system
- Containment penetration areas, including containment isolation valves and Class IE cables
- The control complex including the main control room, reactor protection system, batteries, and dc switchgear
- The spent fuel pit

The AP1000 relies on safety-related systems and equipment to establish and maintain safe shutdown conditions. There are no nonsafety-related systems or components that require protection from missiles.

Evaluations are performed to demonstrate that the criteria are satisfied in the event a credible missile is produced coincident with a single active component failure. These evaluations include the following:

- For those potential missiles considered to be credible, a realistic assessment is made of the postulated missile size and energy, and its potential trajectories.
- Potentially impacted components associated with systems required to achieve and maintain safe shutdown are identified.
- Loss of these potentially impacted components coincident with an assumed single active component failure is evaluated to determine if sufficient redundancy remains to achieve and maintain a safe shutdown condition. If these criteria are satisfied, no further protection is required for the identified missile. If these conditions are not satisfied, additional protective features are incorporated (for example, plant layout is modified, or barriers are added).

3.5.1 Missile Selection and Description

3.5.1.1 Internally Generated Missiles (Outside Containment)

3.5.1.1.1 Criteria for Missile Prevention

Equipment for the AP1000 is selected to minimize the potential for missiles to be generated. Missiles are postulated as described in subsection 3.5.1.1.2. The following items are the major equipment selection considerations with regards to missile prevention:

- Safety-related rotating equipment is designed so that the surrounding housings would contain fragments in the event of failure of the rotating parts.
- Valves that have only a threaded connection between the body and the bonnet are not used in high-energy systems. ASME Code, Section III valves with removable bonnets should be of the pressure-seal type or have bolted bonnets.

- Valve stems of valves located in high-energy systems have at least two retention features. In addition to the stem threads, acceptable features include back seats on the stem or a power actuator, such as an air or motor operator.

- Thermowells and other instrument wells, vents, drains, test connections, and other fittings located in high-energy systems are attached to the piping or pressurized equipment by welding. The completed joint should have a greater design strength than the parent metal. Threaded connections in high-energy systems are avoided.

- High-pressure gas cylinders permanently installed in safety-related areas are constructed to the criteria of ASME Code, Section III or Section VIII. Portable and temporary cylinders and cylinders periodically replaced in safety-related areas are constructed and handled in accordance with applicable Department of Transportation requirements for seamless steel cylinders.

3.5.1.1.2 Missile Selection

3.5.1.1.2.1 Missiles not Considered Credible

This subsection describes internally generated missiles (outside of containment) not considered credible. Missiles not considered credible include the following:

- Catastrophic failure of safety-related rotating equipment (such as pumps, fans, and compressors) leading to the generation of missiles is not considered credible. These components are designed to preclude having sufficient energy to move the masses of their rotating parts through the housings in which they are contained. In addition, material characteristics, inspections, quality control during fabrication and erection, and prudent operation as applied to the particular component reduce the likelihood of missile generation.

- Catastrophic failure of nonsafety-related rotating equipment is not considered credible in situations where measures similar to those just described for safety-related rotating equipment are applied to them. Protection from nonsafety-related equipment will normally be provided by separation. In special situations, equipment features may be used to prevent missile formation.

- Provisions to preclude generation of missiles due to failure of the turbine generator are discussed in subsection 3.5.1.3.

- Missiles originating in non-high-energy fluid systems are not considered credible because these systems have insufficient stored energy.

- The valve bonnets of pressure-seal, bonnet-type valves, constructed in accordance with ASME Code, Section III, are not considered credible missiles. The valve bonnets are prevented from becoming missiles by the retaining ring, which would have to fail in shear, and by the yoke capturing the bonnet or reducing bonnet energy. Because of the conservative design of the retaining ring of these valves, bonnet ejection is unlikely.

- The valves of the bolted bonnet design, constructed in accordance with ASME Code, Section III, are not considered credible missiles. These bolted bonnets are prevented from becoming missiles by limiting stresses in the bonnet-to-body bolting material according to ASME Code, Section III requirements, and by designing flanges in accordance with applicable code requirements. Even if bolt failure would occur, the likelihood of all bolts experiencing simultaneous complete severance failure is not credible. The widespread use of valves with bolted bonnets, and the low historical incidence of complete severance failure of the bonnet, confirm that bolted valve bonnets are not credible missiles. Safety-relief valves in high energy systems use the bolted bonnet design.

- Valve stems are not considered as credible missiles if at least one feature (in addition to the stem threads) is included in their design to prevent ejection. Valve stems with back seats are prevented from becoming missiles by this feature. In addition, the valve stems of valves with power actuators, such as air- or motor-operated valves, are effectively restrained by the valve actuator. Valve stems of rotary motion valves, such as plug valves, ball valves (except single-seat ball valves) and butterfly valves, as well as diaphragm-type valves are not considered as credible missiles. Because these valves do not have a large reservoir of pressurized fluid acting on the valve stem, there is little stored energy available to produce a missile.

- Nuts, bolts, nut and bolt combinations, and nut and stud combinations have only a small amount of stored energy and thus are not considered as credible missiles.

- Thermowells and similar fittings attached to piping or pressurized equipment by welding are not considered as credible missiles where the completed joint has a greater design strength than the parent metal. Such a design makes missile formation not credible. Threaded connections are not used to connect instrumentation to high-energy systems or components.

- Instrumentation such as pressure, level, and flow transmitters and associated piping and tubing are not considered as credible missiles. The quantity of high energy fluid in these instruments is limited and will not result in the generation of missiles. The connecting piping and tubing is made up using welded joints or compression fittings for the tubing. Tubing is small diameter and has only a small amount of stored energy.

- ASME Code, Section III vessel ruptures and ruptures of gas storage vessels constructed without welding using ASME Code, Section VIII criteria are not considered credible due to the conservative design, material characteristics, inspections, quality control during fabrication and erection, and prudent operation.

- Rotating components that operate less than 2 percent of the time are not considered credible sources of missiles. Components that are excluded by this criterion include motors on valve operators and pumps in systems that operate infrequently, such as the chemical and volume control makeup pumps. This exclusion is similar to the exclusion mentioned in subsection 3.6.1.1, that is, of lines from the high-energy category of lines that have limited operating time in high energy conditions.

- Valves, rotating equipment, vessels, and small fittings not otherwise considered to be credible missiles due to design features or other considerations are not considered to be a potential source of missiles when struck by a falling object.

3.5.1.1.2.2 Explosions

Missiles can potentially be generated by a hydrogen explosion. Missiles that could prevent achieving or maintaining a safe shutdown or result in significant release of radioactivity are precluded by design of the plant systems that use or generate hydrogen.

- The battery compartments are ventilated by a system that is designed to preclude the possibility of hydrogen accumulation. Therefore, a hydrogen explosion in a battery compartment is not postulated.

- Hydrogen is supplied from the plant gas storage tank area to the nuclear island. The hydrogen supply is not located in a compartment that contains safety-related systems or components. The quantity that could be released in the event of a failure of the hydrogen supply line is limited to the contents of a single bottle. One hydrogen bottle at a time is connected to the hydrogen supply line. This quantity would not lead to an explosion even if the full contents of a single bottle are assumed to remain in the compartment in which it is released. Mixing within a compartment is achieved by normal convection caused by thermal forces from hot surfaces and air movement due to operation of HVAC systems. The hydrogen supply line is not routed through compartments that do not have air movement due to HVAC systems.

- The storage tank area for plant gases is located sufficiently far from the nuclear island that an explosion would not result in missiles more energetic than the tornado missiles for which the nuclear island is designed.

3.5.1.1.2.3 Missiles to be Considered

The following missiles are considered:

- Nonsafety-related rotating equipment, not excluded above,

- Pressurized components, not excluded above, located in high-energy systems

- High pressure gas storage cylinders that may experience a failure of the outlet pipe or valve if accidentally impacted.

3.5.1.1.2.4 Credible Sources of Internally Generated Missiles (Outside Containment)

The consideration of missile sources outside containment that can adversely affect safety-related structures, systems or components is limited to a few rotating components inside the auxiliary building and a few pressurized components in the chemical volume and control system. The safety-related systems and components needed as described in Section 7.4 to bring the plant to a safe shutdown are located inside the containment shield building and auxiliary building, both of which have thick structural concrete exterior walls that provide protection from missiles generated

in other portions of the plant. Safety-related systems and components located in the auxiliary building, including the main control room, are protected from missiles generated in other portions of the auxiliary building by the structural concrete interior walls and floors. Protection against potential missiles from the turbine-generator is discussed in subsection 3.5.1.3.

Rotating components located inside the auxiliary building that are either safety-related or are constructed as canned motor pumps would contain fragments from a postulated fracture of the rotating elements. These are excluded from evaluation as missile sources. Rotating components used less than 2 percent of the time are also excluded from evaluation as missile sources. This exclusion of equipment that is used for a limited time is similar to the approach used for the definition of high-energy systems. Nonsafety-related rotating equipment in compartments surrounded by structural concrete walls with no safety-related systems or components inside the compartment is not considered a missile source. Rotating equipment with a housing or an enclosure that contains the fragments of a postulated impeller failure is not considered a credible source of missiles. For one or more of these reasons the nonsafety-related rotating equipment inside the auxiliary building is not considered to be a credible missile source. Nonsafety-related rotating equipment in compartments with safety-related systems or components that do not provide other separation features have design requirements for a housing or an enclosure to retain fragments from postulated failures of rotating elements.

The high-energy system inside the auxiliary building that includes pressurized components in the high-energy portions that are constructed to standards other than the ASME Code criteria outlined in subsection 3.5.1.1.1 is the chemical and volume control system. The high-energy portion of this system inside the auxiliary building that is not constructed to ASME Code criteria outlined in subsection 3.5.1.1.1 is from the makeup pumps to the containment and system isolation valves. The nonsafety-related, high-energy portion of this system is not required to be protected from missiles. The nonsafety-related, high-energy portion of the chemical and volume control system is not to be considered a missile source. It includes the design features that are outlined above to exclude components from consideration as missile sources. These considerations include features such as a pump housing or enclosure that contains fragments of a postulated impeller fracture, valve design requirements, vessel design requirements, or enclosure requirements. See Table 3.6-1 for a list of the high-energy systems.

Falling objects (i.e. gravitational missiles) heavy enough to generate a secondary missile are postulated as a result of movement of a heavy load or from a nonseismically designed structure, system, or component during a seismic event. Movements of heavy loads are controlled to protect safety-related structures, systems, and components, see subsection 9.1.5. Safety-related structures, systems, or components are protected from nonseismically designed structures, systems, or components or the interaction is evaluated. See subsection 3.7.3.13 for additional discussion on the interaction of other systems with Seismic Category I systems. Valves, rotating equipment, vessels, and small fittings not otherwise considered to be credible missiles due to design features or other considerations are not considered to be a potential source of missiles when struck by a falling object. The outlet pipes and valves for the air storage bottles for the main control room are constructed to the ASME Code, Section III, requirements and are designed for seismic loads. The attached pipes and valves are not credible missile sources due to an accidental impact. The air storage bottles are located within a structural steel frame and are in an area with no activity

directly above. For the reasons noted above, secondary missiles are not considered credible missiles.

3.5.1.2 Internally Generated Missiles (Inside Containment)

Selection of equipment for the AP1000 considers provisions to minimize the potential for missiles to be generated. The considerations previously discussed in subsection 3.5.1.1 are also applicable to equipment inside the containment.

3.5.1.2.1 Missile Selection

3.5.1.2.1.1 Missiles not Considered Credible

Potential missiles are not considered credible when sufficient energy is not available to produce the missile, or by design the probability of creating a missile is negligible. The following are not considered credible sources of internally generated missiles:

- Reactor coolant pump design requirements are established so that any failure of the rotating parts would be retained within the casing at specified overspeed conditions. This is discussed in subsection 5.4.1.3.6.

- Catastrophic failure of rotating equipment such as pumps, fans, and compressors leading to the generation of missiles is not considered credible as described previously in subsection 3.5.1.1.2.

- Failure of the reactor vessel, steam generators, pressurizer, core makeup tanks, accumulators, reactor coolant pump castings, passive residual heat exchangers, and piping leading to the generation of missiles is not considered credible. This is due to the material characteristics, preservice and inservice inspections, quality control during fabrication, erection and operation, conservative design, and prudent operation as applied to the particular component.

- Gross failure of a control rod drive mechanism housing, sufficient to create a missile from a piece of the housing or to allow a control rod to be ejected rapidly from the core, is not considered credible. This is because of the same reasons listed above for the reactor vessel and other components and is based on the following:

  – The control rod drive mechanisms are shop hydrotested in excess of 150 percent of system design pressure.

  – The housings are individually hydrotested to 125 percent of system design pressure after they are installed on the reactor vessel to the head adapters. They are checked again during the hydrotest of the completed reactor coolant system.

  – The housings are made of Type 304 stainless steel, which exhibits excellent notch toughness.

  – Stress levels in the mechanism are not affected by system thermal transients at power or by thermal movement of the coolant loops.

  - The welds in the pressure boundary of the control rod drive mechanism meet the same design, procedure, examination, and inspection requirements as the welds on other ASME Code, Section III, Class 1 components.

  - A nonmechanistic control rod ejection is considered in the safety analyses in Chapter 15 and the design transients in subsection 3.9.1.1. The integrated head package and control rod drive mechanisms are not designed for the dynamic effects of a missile generated by a rupture of the control rod housing.

- Valves, valve stems, nuts and bolts, and thermowells in high-energy fluid systems and missiles originating in non-high-energy fluid systems are not considered credible missiles as discussed previously in subsection 3.5.1.1.1.

3.5.1.2.1.2 Explosions

Missiles can potentially be generated by a hydrogen explosion. Missiles that could prevent achieving or maintaining a safe shutdown or result in significant release of radioactivity are precluded by design of the plant systems that use or generate hydrogen.

- Hydrogen is supplied by the chemical and volume control system inside containment. The quantity that could be released inside containment in the event of a failure of the hydrogen supply line is limited to the contents of a single bottle. One bottle at a time is connected to the hydrogen supply line. This quantity would not lead to an explosion even if the full contents of a single bottle are assumed to remain in the compartment in which it is released. Mixing within a compartment is achieved by normal convection caused by thermal forces from hot surfaces and air movement due to operation of HVAC systems. The hydrogen supply line is not routed through compartments that do not have air movement due to HVAC systems.

3.5.1.2.1.3 Missiles to be Considered

The following missiles are considered:

- Nonsafety related rotating equipment, not excluded above,

- Pressurized components, not excluded above, located in high-energy systems

3.5.1.2.1.4 Evaluation of Internally Generated Missiles (Inside Containment)

The consideration of credible missile sources inside containment that can adversely affect safety-related structures, systems, or components is limited to a few rotating components. The safety-related systems and components needed to bring the plant to a safe shutdown are inside the containment shield building and auxiliary building both of which have thick structural concrete exterior walls that provide protection from missiles generated in other portions of the plant.

Rotating components inside containment that are either safety-related or are constructed as canned motor pumps would contain fragments from a postulated fracture of the rotating elements and are excluded from evaluation as missile sources. Rotating components in use less than 2 percent of

the time are also excluded from evaluation as missile sources. This exclusion of equipment that is used for a limited time is similar to the approach used for the definition of high-energy systems. This includes the reactor coolant drain pumps, the containment sump pumps and motors for valve operators, and mechanical handling equipment. Non-safety-related rotating equipment in compartments surrounded by structural concrete walls with no safety-related systems or components inside the compartment is not considered a missile source. Rotating equipment with a housing or an enclosure that contains the fragments of a postulated impeller failure is not considered a credible source of missiles. For one or more of these reasons the non-safety-related rotating equipment inside containment is considered not to be a credible missile source. Non-safety-related rotating equipment in compartments with safety-related systems or components that do not provide other separation features has design requirements for a housing or an enclosure to retain fragments from postulated failures of rotating elements.

The high-energy portions of high-energy systems inside the containment shield building except for a portion of the chemical and volume control system are constructed to the requirements of the ASME Code, Section III. The nonsafety-related, high-energy portion of the chemical and volume control system between the inside containment isolation valves and the outermost reactor coolant system isolation valves is not required to be protected from missiles and is not to be considered a missile source. It includes design features outlined above to exclude components from consideration as missile sources. In addition most of the nonsafety-related portion of the chemical and volume control system is contained in a compartment located away from safety-related equipment. See Table 3.6-1 for a list of the high-energy systems.

Falling objects heavy enough to generate a secondary missile are postulated as a result of movement of a heavy load or from a nonseismically designed structure, system, or component during a seismic event. Movements of heavy loads are controlled to protect safety-related structures, systems, and components (see subsection 9.1.5). Design and operational procedures of the polar crane inside containment precludes dropping a heavy load. Additionally, movements of heavy loads inside containment occur during shutdown periods when most of the high-energy systems are depressurized. Valves, rotating equipment, vessels, and small fittings not otherwise considered to be credible missiles due to design features or other considerations are not considered to be a potential source of missiles when struck by a falling object. Secondary missiles are not considered credible. Striking a component with a falling object will not generate a secondary missile if design of the component precludes generation of missiles due to pressurization of the component. Safety-related structures, systems, or components are protected from nonseismically designed structures, systems, or components or the interaction is evaluated. Nonsafety-related equipment that could fall and damage safety-related equipment during an earthquake is classified as seismic Category II and is designed and supported to preclude such failure. See subsection 3.7.3.13 for additional discussion on the interaction of other systems with Seismic Category I systems. There are no high-pressure gas storage cylinders inside the containment shield building. For the reasons noted above, secondary missiles are not considered credible missiles.

3.5.1.3 Turbine Missiles

The turbine generator is located north of the nuclear island with its shaft oriented north-south. In this orientation, the potential for damage from turbine missiles is negligible. Safety-related structures, systems and components are located outside the high-velocity, low-trajectory missile

strike zone, as defined by Regulatory Guide 1.115. Thus, postulated low-trajectory missiles cannot directly strike safety-related areas.

The turbine and rotor design is described in Section 10.2. Protection is provided by the orientation of the turbine-generator and by the use of robust turbine rotors as described in Section 10.2. The rotor design, manufacturing, and material specification and the inspections recommended for the AP1000 provide an acceptably very low probability (see subsection 10.2.2) of missile generation. Turbine rotor integrity is discussed in subsection 10.2.3. This discussion includes fatigue and fracture analysis, material selection, and the maintenance program requirements.

The potential for a high-trajectory missile to impact safety-related areas of the AP1000 is less than 10^{-7}. Based on this very low probability, the potential damage from a high-trajectory missile is not evaluated. The probability of an impact in the safety-related areas is the product of the probability of missile generation from the turbine; the probability, assuming a turbine failure, that a high-trajectory missile would land within a few hundred feet from the turbine (10^{-7} per square foot); and the area of the safety-related area. In the AP1000, the safety-related area is contained within the containment shield building and the auxiliary building.

3.5.1.4 Missiles Generated by Natural Phenomena

Tornado missiles are defined in accordance with Standard Review Plan, Section 3.5.1.4. The velocities are adjusted to the maximum wind velocity defined in Section 3.3 of the DCD. The following missiles are postulated:

- A massive high-kinetic-energy missile, which deforms on impact. It is assumed to be a 4000-pound automobile impacting the structure at normal incidence with a horizontal velocity of 105 mph or a vertical velocity of 74 mph. This missile is considered at all plant elevations up to 30 feet above grade.

- A rigid missile of a size sufficient to test penetration resistance. It is assumed to be a 275 pound, eight inch armor-piercing artillery shell impacting the structure at normal incidence with a horizontal velocity of 105 mph or a vertical velocity of 74 mph.

- A small rigid missile of a size sufficient to just pass through any openings in protective barriers. It is assumed to be a one inch diameter solid steel sphere assumed to impinge upon barrier openings in the most damaging direction at a velocity of 105 mph.

3.5.1.5 Missiles Generated by Events Near the Site

As described previously in Section 2.2, the site interface is established to address site specific missiles in the Combined License application. The AP1000 missile interface criteria are based on the tornado missiles described in subsection 3.5.1.4. Additional analyses are required to evaluate other site specific missiles.

3.5.1.6 Aircraft Hazards

As described previously in Section 2.2, the site interface is established to address aircraft hazards in the Combined License application. The AP1000 missile interface criteria are based on the tornado missiles described in subsection 3.5.1.4. Additional analyses are required to evaluate other site specific missiles.

3.5.2 Protection from Externally Generated Missiles

Systems required for safe shutdown are protected from the effects of missiles. These systems are identified in Section 7.4. Protection from external missiles, including those generated by natural phenomena, is provided by the external walls and roof of the Seismic Category I nuclear island structures. The external walls and roofs are reinforced concrete. The structural design requirements for the shield building and auxiliary building are outlined in subsection 3.8.4. Openings through these walls are evaluated on a case-by-case basis to provide confidence that a missile passing through the opening would not prevent safe shutdown and would not result in an offsite release exceeding the limits defined in 10 CFR 100. The Combined License applicant must evaluate site-specific hazards for external events that may produce missiles more energetic than tornado missiles.

Evaluation of turbine missiles is provided in subsection 3.5.1.3. Evaluation of tornado missiles is provided in subsection 3.5.1.4. Conformance with regulatory guide recommendations is provided in Appendix 1A.

3.5.3 Barrier Design Procedures

Missile barriers and protective structures are designed to withstand and absorb missile impact loads to prevent damage to safety-related components.

Formulae used for missile penetration calculations into steel or concrete barriers are the Modified National Defense Research Committee (NDRC) formula for concrete and either the Ballistic Research Laboratory (BRL) or Stanford formulae for steel.

Concrete (Modified NDRC Formula)

$$x = \left[4\,KNWd\left(\frac{V}{1000\,d}\right)^{1.8}\right]^{0.5} \qquad \text{for } \frac{x}{d} \le 2.0$$

$$x = KNW\left(\frac{V}{1000\,d}\right)^{1.8} + d \qquad \text{for } \frac{x}{d} > 2.0$$

where

x = penetration depth, inches
W = missile weight, lbs
d = missile diameter, inches

N = missile shape factor = 1.0
V = impact velocity, feet/sec
K = experimentally obtained material coefficient for penetration = $\frac{180}{\sqrt{f_c'}}$
f_c' = concrete compressive strength

Scabbing thickness, t_s, and perforation thickness, t_p is given by:

$$\frac{t_s}{d} = 2.12 + 1.36\frac{x}{d} \qquad \text{for } 0.65 \le \frac{x}{d} \le 11.75$$

$$\frac{t_s}{d} = 7.91\left(\frac{x}{d}\right) - 5.06\left(\frac{x}{d}\right)^2 \qquad \text{for } \frac{x}{d} \le 0.65$$

$$\frac{t_p}{d} = 1.32 + 1.24\frac{x}{d} \qquad \text{for } 1.35 \le \frac{x}{d} \le 13.5$$

$$\frac{t_p}{d} = 3.19\left(\frac{x}{d}\right) - 0.718\left(\frac{x}{d}\right)^2 \qquad \text{for } \frac{x}{d} \le 13.5$$

Steel (Stanford Formula)

$$\frac{E}{D} = \frac{S}{46{,}500}\left(16{,}000\,T^2 + 1{,}500\frac{W}{W_s}T\right)$$

Where:

E = critical kinetic energy required for perforation, foot pounds
D = effective missile diameter, inches
S = ultimate tensile strength of the target (steel plate), pounds per square inch
T = target plate thickness, inches
W = length of a square side between rigid supports, inches
W_S = length of a standard window, 4 inches

The ultimate tensile strength is directly reduced by the amount of bilateral tension stress already in the target. The equation is good within the following ranges:

$0.1 < T/D < 0.8$,
$0.002 < T/L < 0.05$,
$10 < L/D < 50$,
$5 < W/D < 8$,
$8 < W/T < 100$,
$70 < V < 400$

Where:

L = missile length, inches
V = impact velocity, feet/second

Steel (BRL Formula)

$$t_p = \frac{(E_k)^{2.3}}{672D}$$

Where:

t_p = steel plate thickness for threshold of perforation, inches
D = equivalent missile diameter, inches
E_k = missile kinetic energy, foot pounds
= $M V^2/2$
M = mass of the missile, lb-sec^2/ft.

In using the Modified NDRC, BRL and Stanford formulae for missile penetration, it is assumed that the missile impacts normal to the plane of the wall on a minimum impact area and, in the case of reinforced concrete, does not strike the reinforcing. Due to the conservative nature of these assumptions, the minimum thickness required for missile shields is taken as the thickness just perforated.

Structural members designed to resist missile impact are designed for flexural, shear, and buckling effects using the equivalent static load obtained from the evaluation of structural response. Stress and strain limits for the equivalent static load comply with applicable codes and Regulatory Guide 1.142, and the limits on ductility of steel structures as given in subsection 3.5.3.1. The consequences of scabbing are evaluated if the thickness is less than the minimum thickness to preclude scabbing.

The thicknesses of the exterior walls above grade and of the roof of the nuclear island are 24 inches and 15 inches, respectively. The roof is constructed using left-in-place metal deck. These thicknesses exceed the minimum thicknesses for Region II tornado missiles specified in Standard Review Plan 3.5.3.

3.5.3.1 Ductility Factors for Steel Structures

Ductility factors for the design of steel structures are as follows:

- For tension due to flexure, $\mu \leq 10.0$
- For columns with slenderness ratio (L/r) equal to or less than 20, $\mu \leq 1.3$
- For columns with slenderness ratio greater than 20, $\mu \leq 1.0$
  Where: L = effective length of the member
  r = the least radius of gyration

- For members subjected to tension, $\mu \leq .5*(e_u/e_y)$
  Where: e_u = ultimate strain
  e_y = yield strain

3.5.4 Combined License Information

The Combined License applicant will demonstrate that the site satisfies the interface requirements provided in Section 2.2. This requires an evaluation for those external events that produce missiles that are more energetic than the tornado missiles postulated for design of the AP1000, or additional analyses of the AP1000 capability to handle the specific hazard.

3.6 Protection Against the Dynamic Effects Associated with the Postulated Rupture of Piping

The effects of a postulated pipe rupture in the AP1000 are of several types. This section considers the effects that are localized to the area of the break and are a result of the dynamic effects of the pipe rupture including jet impingement, pipe whip, subcompartment pressurization, and fluid system decompression. This section describes the evaluation of the potential for and effects of these dynamic effects. It describes measures taken to protect systems and equipment from dynamic effects of pipe rupture when necessary. This section also considers the effects of spray wetting and flooding from pipe ruptures and cracks.

Chapters 6 and 15 discuss the response of the system to changes in flow and pressure and loss of coolant and the response of the containment to the pressure and temperature changes. Pressure due to a break in a high energy line in the auxiliary building is vented into an adjacent building or to the atmosphere. The design transients listed in subsection 3.9.1 are used in evaluating the components of the reactor coolant system for effects due to internal pressure and temperature changes from postulated accidents. Section 3.11 discusses the qualification of the equipment required to function in the adverse environmental conditions including temperature, humidity, pressure, and chemical consequences.

Pipe failure protection is provided according to the requirements of 10 CFR 50, Appendix A, General Design Criterion 4. In the event of a high- or moderate-energy pipe failure within the plant, adequate protection is provided so that essential structures, systems, or components are not impacted by the adverse effects of postulated piping failure. Essential systems and components are those required to shut down the reactor and mitigate the consequences of the postulated piping failure. Nonsafety-related systems are not required to be protected from the dynamic and environmental effects associated with the postulated rupture of piping.

The criteria used to evaluate pipe failure protection are generally consistent with NRC guidelines including those in the Standard Review Plan Sections 3.6.1 and 3.6.2, NUREG-1061, Volume 3 (Reference 11) and applicable Branch Technical Positions.

Subsection 3.6.1 provides the design bases and criteria for the analysis required to demonstrate that essential systems are protected. The high- and moderate-energy systems representing the potential source of dynamic effects are listed. Additionally, the criteria for separation and the effects of adverse consequences are defined.

Subsection 3.6.2 defines the criteria for postulated break location and configuration. High-energy pipes are evaluated for the effects of circumferential and longitudinal pipe breaks and through-wall cracks. Moderate-energy pipes are evaluated for the effects of through-wall cracks. Analysis methods and criteria for evaluating pipe whip and evaluating the consequences of jet impingement, motions of the pipe, and system depressurization on integrity and operability are provided. The evaluation of containment penetrations, pipe whip restraints, guard pipes, and other protective devices is also described. The criteria for excluding breaks in high-energy piping adjacent to containment penetrations are also provided.

Evaluation of the dynamic effects of postulated breaks in the reactor coolant loop, main steam lines inside containment, and other primary piping inside containment equal to or greater than the

6-inch nominal pipe size (NPS) is eliminated for AP1000 based on mechanistic pipe break (leak-before-break) considerations. Those sections of high-energy piping that qualify for mechanistic pipe break are evaluated for only the effects of leakage cracks.

Subsection 3.6.3 describes the application of leak-before-break criteria to permit the elimination of pipe rupture dynamic effects considerations. Design guidelines aid in the design of piping systems that satisfy the requirements for mechanistic pipe break. Dynamic effects of postulated breaks are evaluated for those analyzable sections of high-energy piping systems that do not use the mechanistic pipe break methods.

The safety analyses in Chapter 15 and the requirements for emergency core cooling discussed in Section 6.3 and the environmental qualification of equipment discussed in Section 3.11 of this report are not changed by the use of mechanistic pipe break considerations for pipe rupture dynamic effects evaluations. Chapter 6 describes the containment subcompartment pressurization analyses including mechanistic pipe break considerations.

3.6.1 Postulated Piping Failures in Fluid Systems Inside and Outside Containment

A number of systems and components are necessary to shut the plant down in the event of a pipe rupture. These systems, termed essential systems, are protected from the postulated pipe ruptures. The essential systems for various pipe ruptures are the reactor coolant system, the steam generator system, the passive core cooling system, and the passive containment cooling system. In addition to these fluid systems, the protection and safety monitoring system and the Class 1E dc and UPS system are essential. The main control room and main control room habitability system are also protected as essential systems. In addition, containment penetrations and isolation valves (including those for nonessential systems) are essential.

Most of the equipment required for plant safety or safety-related shutdown is located inside containment. The piping inside containment also represents the most significant piping relative to plant safety and, therefore, is subject to the most stringent design and analysis requirements.

Essential equipment in the vicinity of piping that does not satisfy leak-before-break criteria is protected as required by the use of protective structures, pipe restraints, and separation. The need for protection of essential structures, systems and components is determined by evaluation of the dynamic effects. The design bases and criteria for the evaluation follow.

Evaluations are made based upon circumferential or longitudinal pipe breaks, through-wall cracks, or leakage cracks as determined by the appropriate criteria. At locations determined to be subject to a circumferential or longitudinal pipe break, dynamic effects such as jet impingement and pipe whip are evaluated.

At locations subject to through-wall cracks or leakage cracks, only effects such as spray wetting and flooding are evaluated. Through-wall cracks, which are postulated in high-energy piping and in moderate-energy lines, are larger and have a larger flow rate of water or steam than the leakage cracks postulated for high-energy piping, which satisfies the leak-before-break requirements.

The pressurization loads on structures and components are evaluated for postulated circumferential breaks and longitudinal breaks in piping that does not meet leak-before-break

requirements and for postulated leakage cracks in piping that meets the leak-before-break requirements. See subsections 3.8.3.4 and 3.8.4.3.1.4 for a discussion of pressurization loads on structures.

The in-containment refueling water storage tank is evaluated for pressurization as described in subsection 3.6.1.2.1.

Pressurization loads for pipe failures in the main steam and feedwater break exclusion zones for high-energy lines in the vicinity of containment penetrations are evaluated for a 1.0 square foot break. Structures in the steam generator blowdown break exclusion zone are evaluated for subcompartment pressurization effects due to worst case circumferential pipe rupture in the 4-inch steam generator blowdown piping. Pipe whip and jet impingement are not evaluated for structures in the break exclusion zones per NRC Branch Technical Position MEB 3-1, section B.1.b, except that the east wall and the floor at elevation 117′-6″ of the east main steam subcompartment is designed for pipe whip and jet impingement loads for worst case breaks in either the main steam line or the main feedwater line. See subsection 3.6.2.1.1.4.

3.6.1.1 Design Basis

The following design bases relate to the evaluation of the effects of the pipe failures at locations determined in subsection 3.6.2.

A. The selection of the failure type is based on whether the system is high or moderate-energy during normal operating conditions of the system. High-energy piping includes those systems or portions of systems in which the maximum normal operating temperature exceeds 200°F or the maximum normal operating pressure exceeds 275 psig. Piping systems or portions of systems pressurized above atmospheric pressure during normal plant conditions and not identified as high-energy are considered moderate-energy. Piping systems that exceed 200°F or 275 psig for two percent or less of the time during which the system is in operation or that experience high-energy pressures or temperatures for less than one percent of the plant operation time are considered moderate-energy.

B. The following assumptions are used to determine the thermodynamic state in the piping system for the calculation of fluid reaction forces:

   1. For those portions of piping systems normally pressurized during operation at power, the thermodynamic state in the pipe and associated reservoirs is that of normal full-power operation.

   2. For those portions of piping systems pressurized only during other normal plant conditions (for example, startup, hot standby, reactor cooldown), the thermodynamic state and associated operating condition are determined as the mode giving the most severe fluid reaction forces. Moderate-energy systems that are occasionally at higher temperature or pressure (see design basis A.) are not evaluated for pipe failures at the high-energy conditions.

   3. High-stress pipe rupture locations are based on calculated stresses due to Level A and Level B loading. Seismic loads are not included.

C. Circumferential and longitudinal breaks in high-energy pipes, except in pipes satisfying leak-before-break requirements, are evaluated for effects including subcompartment pressurization, pipe whip, jet impingement, jet reaction thrust, internal fluid decompression loads, spray wetting, and flooding.

D. High-energy and moderate-energy pipe through-wall cracks are evaluated for spray wetting and flooding effects. Dynamic effects are not evaluated for these cracks.

E. Through-wall cracks are not postulated in the break exclusion zones. The effects of flooding, spray wetting, and subcompartment pressurization are evaluated for a postulated 1.0 square foot break for the main steam and feedwater lines.

F. Where postulated, each longitudinal or circumferential break in high-energy fluid system piping, leakage crack in high-energy piping with mechanistic pipe break, or through-wall crack in high-energy or moderate-energy fluid system piping is considered separately as a single initial event occurring during normal plant conditions.

   For systems not seismically analyzed for a safe shutdown earthquake, the safe shutdown earthquake is assumed to cause a pressure boundary failure.

G. Offsite power is not required for the actuation of the passive safety systems. The only electrical system required to function is the Class 1E dc and UPS system.

H. A single active component failure is assumed in systems used to mitigate the consequences of the postulated piping failure or to safely shut down the reactor. The single active component failure is assumed to occur in addition to the postulated piping failure and any direct consequences of the piping failure, such as unit trip and loss of offsite power.

I. The function of the containment to act as the ultimate heat sink is maintained for any postulated pipe rupture.

J. Safety-related systems and components are used to mitigate the effects of postulated pipe ruptures. In addition, the turbine stop, moisture separator reheater stop, and turbine bypass valves (which are not safety-related) are credited in single failure analyses to mitigate postulated steam line ruptures.

K. A whipping pipe is considered capable of rupturing impacted pipes of smaller nominal pipe diameter, irrespective of pipe-wall thickness. This is based on the assumption that only piping is determined to do the impacting. A whipping pipe is considered capable of developing a through-wall crack in a pipe of equal or larger nominal pipe size with equal or thinner wall thickness, assuming that only piping is determined to do the impacting. The preceding criterion is not used where the potential exists for valves or other components in the whipping pipe to impact the targets, since these are treated on a case-by-case basis.

L. Pipe whip is assumed to occur in the plane defined by the piping geometry and to cause movement in the direction of the jet reaction.

If unrestrained, a whipping pipe having a constant energy source sufficient to form a plastic hinge is considered to form a plastic hinge and rotate about the nearest rigid pipe whip restraint, anchor, or wall penetration capable of resisting the pipe whip loads or the calculated dynamic plastic hinge location.

If the direction of the initial pipe movement caused by the thrust force is such that the whipping pipe impacts a flat surface normal to its direction of travel, it is assumed that the pipe comes to rest against that surface, with no pipe whip in other directions.

Pipe whip restraints are provided wherever postulated pipe breaks could impair the capability of any essential system or component to perform its intended safety functions.

M. The calculation of thrust and jet impingement forces considers any line restrictions (that is, flow limiter) between the pressure source and break location and the absence of energy reservoirs, as applicable.

N. Breaks are not postulated to occur in pump and valve bodies since the wall thickness exceeds that of connecting pipe.

O. Components impacted by jets from breaks in piping containing high-pressure (870 to 2465 psia) steam or subcooled liquid that would flash at the break, such as piping connected to the steam generators or reactor coolant loops, are evaluated as follows:

   1. Impacted components within 10 piping diameters of the broken pipe are assumed to fail. Specific jet loads are calculated and evaluated only when failure of the component, when combined with a single active failure, could adversely affect safe shutdown or accident mitigation capability. These jet loads are calculated according to subsection 3.6.2.2.

   2. Components beyond 10 diameters of the broken pipe are considered to be undamaged by the jet and are not analyzed. The basis for these criteria is contained in NUREG/CR-2913 (Reference 1).

P. Pipe breaks are not postulated to occur in systems for which postulated leakage cracks have been shown to be stable for worst case loadings. (See subsection 3.6.3.) Leak detection systems are provided that are capable of detecting the leakage from a postulated leakage crack.

For these systems, leakage cracks are postulated and evaluated for subcompartment pressure loads on structures and components. When the mechanistic pipe break approach is used, subcompartment pressure loads on structures and essential components are based on the small leakage crack determined from the mechanistic pipe break approach. Where the subcompartment includes lines not qualified for mechanistic pipe break, subcompartment pressurization is evaluated for a break in the line with the largest effect.

The leakage crack effects of jet impingement, pipe whip, and internal fluid system loads are considered negligible and are not evaluated. The leakage crack effects of flooding and environmental effects are less limiting than the corresponding effects for postulated

high-energy through-wall cracks. These through-wall cracks are not eliminated by mechanistic pipe break.

Q. Nonessential systems, structures, and components are not required to meet the criteria outlined in this section. However, while none of the nonessential systems are needed during or following a pipe break event, pipe whip protection is evaluated in cases where a high-energy nonessential system failure could initiate a failure in an essential system or component or where a high-energy nonessential system failure could initiate a failure in another nonessential system whose failure could affect an essential system.

R. The escape of steam, water, combustible or corrosive fluids, gases, and heat in the event of a pipe rupture will not preclude:

- Subsequent access to any areas, as required, to recover from the postulated pipe rupture
- Habitability of the control room
- Capability of essential instrumentation, electric power supplies, components, and controls to perform safety functions to the extent necessary to meet the criteria outlined in this section

3.6.1.2 Description

Essential systems are evaluated to demonstrate conformance with the design bases and to determine their susceptibility to the failure effects. Table 3.6-1 identifies systems which contain high and moderate-energy lines. The systems listed include all high- and moderate-energy systems inside containment plus the high- and moderate-energy systems in the auxiliary building near containment penetrations (including access hatches), the main control room, the Class 1E dc and UPS system or the portions of the passive containment cooling system located in the auxiliary building. The table does not list systems that operate at or close to atmospheric pressure including air handling and gravity drains. High energy system piping in the turbine building adjacent to the auxiliary building is evaluated for potential effects on the main control room. These systems are included on Table 3.6-1.

The definition of high and moderate-energy systems is provided in paragraph A of subsection 3.6.1.1.

The postulated break, through-wall crack, and leakage crack locations are determined according to subsections 3.6.2 and 3.6.3.

Equipment is considered to be separated from the dynamic effects of pipe rupture when the equipment is located in a different subcompartment. For the case of pipe whip, equipment may be considered separated for dynamic effects based on the distance from the pipe and the length of pipe that is moving. For the case of jet impingement in a line with saturated or subcooled fluid, equipment more than ten pipe diameters from the break location is considered separated for dynamic effects.

Equipment located in the same subcompartment as a break, through-wall crack, or leakage crack is subject to potential environmental and flooding effects. Equipment may also be subject to environmental and flooding effects of steam and water vented into a subcompartment from an adjoining subcompartment.

3.6.1.2.1 Pressurization Response

Pressurization response analyses are performed for subcompartments containing high-energy piping for which break locations are defined by subsections 3.6.2.1.1.1, 3.6.2.1.1.2, and 3.6.2.1.1.3 or postulated leakage flaws are defined based on subsection 3.6.3.3. Table 3.6-2 identifies those terminal end pipe breaks considered for the evaluation of the effects of pressurization loads on subcompartments. The terminal end pipe breaks inside containment that are postulated in piping that is not evaluated to the leak-before-break requirements of subsection 3.6.3 are summarized in Table 3.6-2. The subcompartments are identified using the room numbers and room names given on Figures 1.2-4 through 1.2-10 as supplemented by Table 3.6-2. The subcompartments inside containment are designed to accommodate the pressurization loads from these breaks. In order to account for high stress break locations and the additional pressure boundary leakages from manways and flanges, pressurization loads on compartments inside containment enclosing high-energy piping are designed as described in subsection 3.8.3.4.

There is no high-energy piping that can pressurize the annulus between the containment vessel and the shield building. Guard pipes are provided for the main steam, feedwater, and steam generator blowdown containment penetrations passing through the annulus as shown on Figure 3.8.2-4. The chemical and volume control system makeup piping is classified as high energy due to its design pressure, but does not cause pressurization because it is at ambient temperature.

The pressurization loads for the in-containment refueling water storage tank are based on the pressure and hydrodynamic loads due to the maximum discharge through the first, second, and third stages of the automatic depressurization system valves.

The pressurization loads for the reactor vessel annulus for the evaluation of asymmetric compartment pressurization are based on a 5-gallon per minute leakage crack in the primary loop piping. The internal reactor pressure vessel asymmetric pressurization loads are based on a break in the largest pipe connected to the reactor coolant system that does not qualify for the application of mechanistic pipe break.

There are limited areas in the auxiliary building where the potential for pressurization loads from high-energy lines are considered. The pressurization loads for the steam tunnels are addressed in the discussion of loads due to a break in the break exclusion zone of the main steam and feedwater lines. The pressurization loads for the Elevation 100′ containment penetration room containing the steam generator blowdown break exclusion zone are based on a circumferential rupture of the 4-inch steam generator blowdown piping. The areas through which the chemical and volume control system make-up line run, including the annulus between the containment and the containment shield building, are not subject to pressurization since the temperature of these lines is less than 212°F.

For a discussion of the criteria and analysis methods for subcompartment pressurization analysis, see subsection 6.2.1.2. The analytical methods for transient mass distribution, used for pressure response analysis, are the same as described in WCAP-8077 (Reference 2).

3.6.1.2.2 Main Control Room Habitability

The high-energy lines in closest proximity to the main control room are the main steam line and main feedwater line. The portions of these lines near the main control room are in the main steam line isolation valve compartment and are part of the break exclusion areas.

The main control room is separated from the isolation valve compartment by two structural walls. The areas between the two walls is used for nonessential office and administrative space associated with the control room. The walls separating the main control room from the main steam isolation valve compartment are thick, reinforced-concrete walls.

Consistent with the criteria for evaluation of leaks in the break exclusion area, the subcompartment, including the walls, is evaluated for the effects of flooding, spray wetting and subcompartment pressurization from a 1-square-foot break from either main steam or feedwater line within the respective break exclusion areas. The wall between the main steam line isolation valve compartment and the main control room, and the floor slab between the main steam line isolation valve compartment and the safety related electrical equipment room are also evaluated for pipe whip and jet impingement loads for worse case breaks in either the main steam line or the main feedwater line.

The effects upon the habitability of the main control room resulting from postulated pipe breaks and cracks in the auxiliary building are evaluated. In addition to pipe ruptures and cracks in lines in the auxiliary building, the main control room is evaluated for the dynamic effects and environmental effects of a postulated circumferential or longitudinal break of either the main steam line or main feedwater line in the turbine building.

Further description of the control room habitability systems, including options for remote shutdown, is provided in Section 6.4. The remote shutdown workstation is not subject to adverse effects of high-energy pipe rupture.

3.6.1.3 Safety Evaluation

3.6.1.3.1 General

An analysis of postulated pipe failures is performed to determine the impact of such failures on those safety-related systems or components that provide protective actions and are required to mitigate the consequences of the failure. Through such protective measures, as separation, barriers, and pipe whip restraints, the effects of breaks, through-wall cracks, and leakage cracks are prevented from damaging essential items to an extent that would impair their essential function or necessary component operability.

Typical measures used for protecting the essential systems, components, and equipment are outlined in the next subsection and are discussed in subsection 3.6.2. The capability of specific safety-related systems to withstand a single active failure concurrent with the postulated event is

discussed, as applicable. When the results of the pipe failure effects analysis show that the effects of a postulated pipe failure are isolated, physically remote, or restrained by protective measures from essential systems or components, no further dynamic analysis is performed.

3.6.1.3.2 Protection Mechanisms

The plant arrangement is based on maximizing the physical separation of redundant or diverse safety-related components and systems from each other and from nonsafety-related items. Therefore, in the event a pipe failure occurs, there is a minimal effect on other essential systems or components required for safe shutdown of the plant or to mitigate the consequences of the failure.

The effects associated with a particular pipe failure are mechanistically consistent with the failure. Thus, pipe dimensions, piping layouts, material properties, and equipment arrangements are considered in defining the specific measures for protection against the consequences of postulated failures.

Protection against the dynamic effects of pipe failures is provided by physical separation of systems and components, barriers, equipment shields, and pipe whip restraints. The precise method chosen depends largely upon considerations such as accessibility and maintenance. The preferred method of providing protection is by separation. When separation is not practical pipe whip restraints are used. Barriers or shields are used when neither separation nor pipe whip restraints are practical. This protection is not required when piping satisfies leak-before-break criteria.

Separation

The plant arrangement provides separation, to the extent practicable, between redundant safety systems (including their appurtenances) to prevent loss of safety function as a result of events for which the system is required to be functional. Separation between redundant safety systems, with their related appurtenances, therefore, is the basic protective measure incorporated in the design to protect against the dynamic effects of postulated pipe failures.

In general, separation is achieved by:

- Safety-related systems located remotely from high-energy piping, where practicable
- Redundant safety systems located in separate compartments, where practicable
- Specific components enclosed to retain the redundancy required for those systems that must function to mitigate specific piping failures
- Drainage systems provided for flooding control

Where physical separation is not possible, the pipe rupture hazard analysis includes an evaluation to determine the systems and components that require a structure for separation from the effects of a break in a high energy line. For these structures specifically included to separate breaks from essential systems or components, the evaluation considers that the break may be at the closest point in the line to the separating structure; not only at the break locations identified in

subsection 3.6.2.1.1. High energy lines qualified as leak-before-break lines and the lines in containment penetration break exclusion areas are not included as possible break locations in this evaluation. For a discussion of the information included in the pipe rupture hazard analysis see subsection 3.6.2.5.

Barriers and Shields

Protection requirements are met through the protection afforded by walls, floors, columns, abutments, and foundations. Where adequate protection does not already exist as a result of separation, a separating structure such as additional barriers, deflectors, or shields is provided to meet the functional protection requirements.

Inside the containment, the secondary shield wall serves as a barrier between the reactor coolant loops and the containment. In addition, the refueling cavity walls, operating floor, and secondary shield walls minimize the possibility of an accident that may occur in any one reactor coolant loop affecting the other loop or the containment. Those portions of the steam and feedwater lines located within the containment are routed in such a manner that possible interaction between these lines and the reactor coolant piping is minimized. The direct vessel injection valves for train A and train B are separated by the secondary shield wall.

Barriers and shields that are identified as required by the pipe rupture hazard analysis are designed for loads from a break in the line at the closest location to the structure. This criterion is in conformance with the guidance of Branch Technical Position MEB 3-1. Rev. 2. Subsection 3.6.2.4 further discusses barriers and shields.

Piping Restraint Protection

Measures for protection against pipe whip are provided where the unrestrained pipe movement of either end of the ruptured pipe could cause damage at an unacceptable level to any structure, system, or components required to meet the criteria outlined in this subsection.

Subsection 3.6.2.3 gives the design criteria for and description of pipe whip restraints.

3.6.1.3.3 Specific Protection Considerations

The analysis of the consequences of pipe breaks, through-wall cracks, and leakage cracks uses the following criteria.

- High-energy containment penetrations are subject to special protection mechanisms. Restraints are provided to maintain the operability of the isolation valves and the integrity of the penetration due to a break in the safety-related and nonsafety piping beyond the restraint if required. These restraints are located as close as practicable to the containment isolation valves associated with these penetrations.

- Instrumentation required to function following a pipe rupture is protected. In the event of a high-energy line break outside containment, the only safety-related instrumentation that could be affected is the pressure and flow instrumentation in the main steam isolation valve (MSIV) compartment. This instrumentation is qualified for the environmental

conditions resulting from a 1-square-foot break from either main steam or feedwater line in the MSIV compartment as required in order to perform its safety functions.

- High-energy fluid system pipe whip restraints and protective measures are designed so that a postulated break in one pipe cannot lead to a rupture of other nearby essential pipes or components, if the secondary rupture results in consequences that are unacceptable for the initial postulated break.

For those cases in which the rupture of the main steam or feedwater piping inside containment is the postulated initiating event the turbine control, turbine stop, moisture separator reheater stop, and turbine bypass valves and to a limited extent, the control systems for the turbine stop and feedwater control valves (which are nonsafety-related equipment) are credited in single failure analysis to mitigate the event. This equipment is not protected from pipe ruptures in the turbine building because the postulated pipe rupture for which it provides protection is inside containment. The assumed single active failure for this analysis is the function of the safety-related valve that would normally isolate the piping. This isolation function is addressed in more detail in Chapter 10.

The hot water heating system is a high-energy system since the operating temperature is greater than 200°F. The hot water heating system lines in auxiliary building subcompartments that include safety-related systems or components are restricted to a nominal pipe diameter of 1 inch or less.

3.6.2 Determination of Break Locations and Dynamic Effects Associated with the Postulated Rupture of Piping

This subsection describes the design bases for locating postulated breaks and cracks in high- and moderate-energy piping systems inside and outside the containment; the procedures used to define the jet thrust reaction at the break location; the procedures used to define the jet impingement loading on adjacent essential structures, systems, or components; pipe whip restraint design; and the protective assembly design. Pipe breaks in several high-energy systems, including the reactor coolant loop and surge line, are replaced by small leakage cracks when the leak-before-break criteria are applied. (See subsection 3.6.3.) Jet impingement and pipe whip effects are not evaluated for these small leakage cracks.

3.6.2.1 Criteria Used to Define High- and Moderate-Energy Break and Crack Locations and Configurations

The NRC Branch Technical Position MEB 3-1 is used as the basis of the criteria for the postulation of high-energy pipe breaks and through-wall cracks, except for piping that satisfies the requirements for mechanistic pipe break, as described in subsection 3.6.3.

A postulated high-energy pipe break is defined as a sudden, gross failure of the pressure boundary of a pipe either in the form of a complete circumferential severance (that is, a guillotine break) or as a sudden longitudinal, uncontrolled crack. For high-energy and moderate-energy fluid systems, pipe failures are also defined by postulation of controlled through-wall cracks in piping. For those piping lines that satisfy leak-before-break requirements, the guillotine breaks and sudden longitudinal cracks are replaced by postulated controlled leakage cracks.

Subsection 3.6.1 describes the evaluation and criteria for the effects of these breaks and cracks on the safety-related equipment.

3.6.2.1.1 High-Energy Break Locations

The locations for postulated breaks in high-energy piping are dependent on the classification, quality group, and design standards used for the piping system. The break locations for high-energy piping are described in the following subsections. These locations are based on the design configuration and include changes due to the as-built piping configuration. As a result of piping reanalysis due to differences between the design configuration and the as-built configuration, the high stress and usage factor location may be shifted. The intermediate break (if any) locations need not be changed unless one of the following conditions exists:

A. The dynamic effects from new (as-built) intermediate break locations are not mitigated by the original pipe whip restraints and jet shields.

B. There is a significant change in pipe design parameters such as pipe size, wall thickness or pressure rating.

Breaks are not postulated in piping in the vicinity of containment penetrations. The portion of the piping that does not have postulated breaks is the break exclusion area. Subsection 3.6.2.1.1.4 identifies the requirements for the piping in the containment penetration break exclusion area.

Breaks are not postulated for those sections of pipe, including the reactor coolant loop and pressurizer surge line, that meet the requirements for leak-before-break as described in subsection 3.6.3.

The leak-before-break methodology is applied to the candidate high-energy lines in the nuclear island identified in Appendix 3E. This appendix also identifies other high-energy lines in the nuclear island with diameters larger than 1 inch and the break exclusion areas outside containment. The evaluation criteria for lines that do not satisfy the leak-before-break criteria are described in subsection 3.6.2.

3.6.2.1.1.1 ASME Code, Section III, Division 1 – Class 1 Piping

[*Pipe breaks are postulated to occur at the following locations in piping designed and constructed to the requirements for Class 1 piping in the ASME Code, Section III, Division 1.*

- *At terminal ends of the piping, including:*
  - *The extremity of piping connected to structures, components, or anchors that act as essentially rigid restraints to piping translation and rotational motion due to static or dynamic loading.*
  - *Branch intersection points are considered a terminal end for the branch line unless the following are met: The branch and the main piping systems are modeled in the same static, dynamic and thermal analyses, and the branch and main run are of comparable*

size and fixity (that is, the nominal size of the branch is at least one-half of that of the main run).

– *In piping runs that are maintained pressurized during normal plant conditions for only a portion of the run, the terminal end, for purposes of defining break locations, is the piping connection to the first normally closed valve.*

- *At intermediate locations where the following conditions are satisfied:*

  – *Intermediate locations where the maximum stress range as calculated by Equation (10) of Paragraph NB-3653 of the ASME Code, Section III exceeds 2.4 Sm (where Sm is the design stress intensity), and either Equation (12) or Equation (13) of Paragraph NB-3653.6, exceed 2.4 Sm.*

  – *Intermediate locations where the cumulative usage factor as determined by the ASME Code exceeds 0.1.*

  – *Efforts will be made to avoid intermediate break locations through appropriate piping layout and pipe support design.*

The loading conditions considered for the stress range and usage factors calculated to determine break locations are those defined for Level A and B Service conditions for the piping system with the exception that seismic loads do not need to be considered for the postulation of intermediate break locations.

For those sections of pipe that satisfy the requirements for leak-before-break, leakage cracks are postulated for evaluation of subcompartment pressurization.]*

3.6.2.1.1.2 ASME Code, Section III – Class 2 and Class 3 Piping Systems

[*For those piping system lines designed and analyzed to the requirements of the ASME Code, Section III, Class 2 and 3, except for those sections that satisfy the mechanistic pipe break criteria (subsection 3.6.3), the following criteria apply.*

- *Pipe breaks are postulated to occur at terminal ends, using the same definition for terminal ends as for Class 1 pipe.*

- *Pipe breaks are postulated at intermediate locations between terminal ends where the maximum stress value, as calculated by the sum of Equations (9) and (10) in Subarticle NC-3600 (Class 2) and ND-3600 (Class 3) of the ASME Code, Section III, considering Level A and B Service conditions. That is, breaks are postulated at locations for sustained loads, occasional loads, and thermal expansion exceeding 0.8 (1.8 Sh + SA) or 0.8 (1.5 Sy + SA), where Sh, SA, and Sy are the allowable stress at maximum hot temperature stress, allowable stress range for thermal expansion, and yield strength, respectively, for Class 2 and 3 piping, as defined in Subarticle NC-3600 and Subarticle ND-3600 of the ASME Code, Section III. Efforts will be made to avoid intermediate break locations through appropriate piping layout and pipe support design.*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

For those ASME Code, Section III, Class 2 and 3 systems that satisfy the leak-before-break criteria, postulated leakage crack locations are defined in the same way as for the Class 1 systems.]*

3.6.2.1.1.3 Piping Not Designed to ASME Code

[*Breaks in piping systems designed to requirements other than the ASME Code, such as ASME-B31.1 (Reference 3), are postulated at the following locations:*

- *If the piping is analyzed and supported to withstand safe shutdown earthquake loadings, pipe ruptures are postulated to occur at the following locations:*
  - *At terminal ends, using the same definition for terminal ends as for Class 1 pipe*
  - *At intermediate locations where the stresses, as calculated by the sum of Equations (9) and (10) in Subarticle NC3600 of the ASME Code, Section III, considering normal and upset plant conditions, exceeds 0.8 (1.8 Sh + SA) or 0.8 (1.5 Sy + SA)*
  - *Efforts will be made to avoid intermediate break locations through appropriate piping layout and pipe support design.*]*
- In the absence of stress analysis, breaks in non-nuclear piping are postulated at the following locations in each run or branch run:
  - Terminal ends
  - Intermediate fittings; (short- and long-radius elbows, crosses, flanges, nonstandard fittings, tees, reducers, welded attachments, and valves)

3.6.2.1.1.4 High-Energy Piping in Containment Penetration Areas

The AP1000 does not have any ASME Code, Section III Class 1 pipe in containment penetration areas. Breaks are not postulated in the portions of ASME Code, Section III, Class 2 or Class 3 piping between the containment penetration flued-head and auxiliary building anchor beyond the isolation valve (that is, the break exclusion zone adjacent to the containment penetrations) provided subject piping meets the following provisions:

- Stresses do not exceed those specified in subsection 3.6.2.1.1.2.
- The maximum stress in this piping as calculated by Equation (9), of paragraph NC-3652 of ASME Code Section III, when subjected to the combined loadings of internal pressure, deadweight, and postulated pipe rupture outside the break exclusion zone, does not exceed 2.25 Sh or 1.8 Sy.
- The number of circumferential piping welds is minimized by using pipe bends in place of welding elbows when practicable. There are no longitudinal piping welds in the break exclusion zone. Where guard pipes are used, there are no circumferential or longitudinal welds in the piping enclosed within the guard pipe. Details of the arrangement are shown in Figure 3.8.2-4.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- When required for isolation valve operability, structural integrity, or containment integrity, anchors or five-way restraints capable of resisting torsional and bending moments produced by a postulated pipe break, either upstream or downstream of the piping and valves which form the containment isolation boundary, are located reasonably close to the isolation valves or penetration.

  The anchors or five-way restraints do not prevent the access required to conduct in-service inspection examinations specified in Section XI of the ASME Code. In-service examinations completed during each inspection interval provide 100-percent volumetric examination (according to IWA-2400, ASME Code, Section XI) of circumferential pipe welds within the boundary of these portions of piping during each inspection interval. This volumetric inspection applies to piping that is equal to or greater than a 3-inch nominal diameter.

- Welded attachments to these portions of piping for pipe supports or other purposes are avoided. Where welded attachments are necessary, detailed stress analyses are performed to demonstrate compliance with the limits of subsection 3.6.2.1.1 and applicable requirements of Section XI of the ASME Code.

- The requirements of ASME Code, Section III, Subarticle NE-1120, are satisfied for the containment penetration.

- Class 3 pipe satisfies the fabrication and inspection requirements for Section III, Class 2 pipe.

- For evaluation of spray wetting, flooding, and subcompartment pressurization effects, longitudinal cracks (with crack flow areas of 1 square foot) are postulated in the main steam and main feedwater piping. The dynamic effects of pipe whip and jet impingement are not evaluated for these cracks. Locations having the greatest effect on essential equipment are chosen.

- Guard pipe assemblies for high-energy piping in the containment annulus region between the containment shell and shield building that are part of the containment boundary are designed according to the rules of Class MC, subsection NE, of the ASME Code. The following requirements also apply. The design pressure and temperature are equal to or greater than the maximum operating pressure and temperature of the enclosed process pipe under normal plant conditions. Level C service limits of the ASME Code, Section III, Paragraph NE-3221(c), are not exceeded by the loadings associated with containment design pressure and temperature in combination with a safe shutdown earthquake. The guard pipe assemblies are subjected to a pressure test performed at the maximum operating pressure of the enclosed process pipe.

Areas of system piping where no breaks, except as noted in subsections 3.6.1.3 and 3.6.1.2.2, are postulated are as follows:

- The main steam piping, from the containment penetration flued head outboard weld, to the upstream weld of the auxiliary building anchor downstream of the main steam isolation valves, including the main steam safety valves and the connecting branch piping

- The main feedwater piping, from the containment penetration flued head outboard weld, to the auxiliary building anchor upstream of the isolation valve

- The startup feedwater piping from the containment penetration to the auxiliary building anchor upstream of the isolation valve

- The steam generator blowdown piping from the containment to auxiliary building anchor downstream of the isolation valve

- The chemical and volume control system makeup piping from the containment to the outboard isolation valve

- The chemical and volume control system makeup piping from the containment to the inboard isolation valve

All other fluid system containment penetrations are for moderate-energy systems or for pipe of 1-inch nominal diameter or smaller. See subsection 6.2.3 for a discussion of containment penetrations.

3.6.2.1.2 Types of Breaks/Cracks Postulated

3.6.2.1.2.1 Break in Piping – High-Energy

The following types of breaks are postulated to occur in ASME Code Class 1, 2, and 3 and non-ASME Code, Section III high-energy piping at the locations determined according to subsection 3.6.2.1.1, except when the leak-before-break criteria are satisfied.

- In piping with a nominal diameter of greater than or equal to 4 inches, both circumferential and longitudinal breaks are postulated at each selected break location unless eliminated by comparison of longitudinal and axial stresses with the maximum stress as follows:

  – If the maximum stress range exceeds the limits specified in subsections 3.6.2.1.1.1, 3.6.2.1.1.2, and 3.6.2.1.1.3, but the circumferential stress range is at least 1.5 times the axial stress range, only a longitudinal break is postulated.

  – If the maximum stress range exceeds the limits specified in subsections 3.6.2.1.1.1, 3.6.2.1.1.2, and 3.6.2.1.1.3, but the axial stress is at least 1.5 times the circumferential stress range, only a circumferential break is postulated.

  – Longitudinal breaks, however, are not postulated at terminal ends.

- In piping with a nominal diameter of greater than 1 inch but less than 4 inches, only circumferential breaks are postulated at each selected break location.

- No breaks are postulated for piping with a nominal diameter of 1 inch or less.

3.6.2.1.2.2 Through-Wall Cracks in High- or Moderate-Energy Piping

Through-wall cracks are postulated in high-energy or moderate-energy piping, including branch runs larger than 1-inch nominal diameter as defined in the following paragraphs:

A. Through-wall cracks are not postulated in the break exclusion areas of high-energy pipe defined in subsection 3.6.2.1.1.4 and in those portions of moderate-energy piping between containment isolation valves, provided the containment penetration meets the requirements of ASME Code, Section III, Sub-article NE-1120, and the piping is designed so that the maximum stress range based on the sum of equations (9) and (10) in Subarticle NC3600 of the ASME Code, Section III, does not exceed 0.4 (1.2 Sh + SA).

B. Through-wall cracks are not postulated in high- or moderate-energy fluid system piping located in an area where a break in the high-energy fluid system is postulated, provided that such cracks do not result in environmental conditions more limiting than the high-energy pipe break.

C. Subject to Paragraphs A and D, through-wall cracks are postulated in:

- ASME Code, Section III, Division 1 – Class 1 piping where the maximum stress range as calculated by Equation (10) of Paragraph NB-3653 of the ASME Code, Section III exceeds 1.2 Sm. Cracks are also postulated at locations where the cumulative usage factor exceeds 0.1.

- ASME Code, Section III, Division 1 – Class 2 or 3 piping at locations where the maximum stress range, as calculated by the sum of Equations (9) and (10) in Subarticle NC-3600 (Class 2) and ND-3600 (Class 3) of the ASME Code, Section III, considering Level A and B Service conditions, in the piping is greater than 0.4 (1.8 Sh + SA) or 0.4 (1.5 Sy + SA).

- Seismically analyzed ASME-B31.1 piping at locations defined in the same way as ASME Code, Section III, Class 3 piping.

- Nonseismically analyzed ASME-B31.1 piping at the following locations:

  – Terminal ends

  – Intermediate fittings; (short- and long-radius elbows, crosses, flanges, nonstandard fittings, tees, reducers, welded attachments, and valves)

D. Individual through-wall cracks are not postulated at specific locations determined by stress analyses when a review of the piping layout and plant arrangement drawings shows that the effects of through-wall leakage cracks at any location in the piping designed to seismic or nonseismic standards are isolated or are physically remote from structures, systems, and components required for safe shutdown.

E. Through-wall cracks are postulated to be in those circumferential locations that result in the most severe environmental consequences.

3.6.2.1.2.3 Leakage Cracks in High-Energy Piping with Leak-before-Break

In those sections of piping that satisfy the requirements for leak-before-break, leakage cracks are postulated for evaluation of subcompartment pressurization. The size of the crack is such that the expected leakage is 10 times the minimum leak detection capability for that location. See subsection 3.6.3 for a discussion of crack size and leakage detection.

3.6.2.1.3 Break and Crack Configuration

3.6.2.1.3.1 High-Energy Break Configuration

Following a circumferential break, the two ends of the broken pipe are assumed to move clear of each other unless physically limited by piping restraints, structural members, or piping stiffness. The effective cross-sectional (inside diameter) flow area of the pipe is used in the jet discharge evaluation. Movement is assumed to be in the direction of the jet reaction initially with the total path controlled by the piping geometry.

The orientation of a longitudinal break, except when otherwise justified by a detailed stress analysis, is assumed to be at opposing points on a line perpendicular to the plane of a fitting for a non-axisymmetric fitting. The flow area of such a break is equal to the cross-sectional flow area of the pipe. The geometry of the longitudinal break may be assumed elliptical (2D along pipe axis and D/2 along pipe transverse) or circular. Both circumferential and longitudinal breaks are postulated to occur, but not concurrently, in high-energy piping systems at the locations specified in subsection 3.6.2.1.2.1, except as follows:

- Where the postulated break location is at a tee or elbow, the locations and types of breaks are determined as follows:
  - Without the benefit of a detailed stress analysis, such as a finite element analysis, circumferential breaks are postulated to occur individually at each pipe-to-fitting weld. Longitudinal breaks are postulated to occur individually (except in piping with a nominal diameter less than 4-inches) on each side of the fitting at its center and oriented perpendicular to the plane of the fitting, or
  - Alternatively, if a detailed stress analysis or test is performed, the results may be used to predict the most probable rupture location(s) and type of break.
- Where the postulated break location is at a branch/run connection, a circumferential break is postulated at the branch pipe-to-branch fitting weld unless otherwise justified by detailed analysis.
- Where the postulated break location is at a welded attachment (lugs, stanchions), a circumferentially oriented break is postulated at the centerline of the welded attachment unless otherwise justified by a detailed analysis. The break area is equal to the pipe surface area that is bounded by the welded attachment.

- Where the postulated break location is at a reducer, circumferential breaks are postulated at each pipe-to-fitting weld. Longitudinal breaks are oriented to produce out-of-plane bending of the piping configuration on both sides of the reducer at each pipe-to-fitting weld.

3.6.2.1.3.2 High-Energy and Moderate-Energy Through-Wall Crack Configuration

High-and moderate-energy through-wall crack openings are assumed to be a circular orifice with cross-sectional flow area equal to that of a rectangle one-half the pipe inside diameter in length and one-half pipe wall thickness in width. The flow from a through-wall crack is assumed to result in an environment that wets unprotected components within the compartment with consequent flooding in the compartment and communicating compartments, unless analysis shows otherwise. Flooding effects are determined on the basis of a conservatively estimated time period required to take corrective actions.

3.6.2.2 Analytical Methods to Define Jet Thrust Forcing Functions and Response Models

To determine the forcing function, the fluid conditions at the upstream source and at the break exit dictate the analytical approach and approximations that are used.

Analytical methods for calculation of jet thrust for the preceding situations are discussed in ANS-58.2-1988 (Reference 4) and Moody, F. J. (Reference 5). The discussion of the jet thrust forcing functions on the reactor coolant loop follows.

Since a rupture of the large-diameter reactor coolant loop piping does not have to be considered, based on satisfying mechanistic pipe break criteria, the jet thrust and reactive loads considered in the analysis are those associated with breaks in branch line sections that do not satisfy the mechanistic pipe break criteria.

To determine the thrust and reactive force loads to be applied to the reactor coolant loop during the postulated pipe rupture, it is necessary to have a detailed description of the hydraulic transient. Hydraulic forcing functions are calculated for the reactor coolant loops as a result of a postulated loss of coolant accident. These forces result from the transient flow and pressure histories in the reactor coolant system (RCS).

The calculation is performed in two steps. The first step is to calculate the transient pressure, mass flow rates, and thermodynamic properties as a function of time. The second step uses the results obtained from the hydraulic analysis, along with input of areas and direction coordinates, and calculates the time-history of forces at appropriate locations in the reactor coolant loops.

The hydraulic model represents the behavior of the coolant fluid within the entire reactor coolant system. Key parameters calculated by the hydraulic model are pressure, mass flow rate, and density. These are supplied to the thrust calculation, together with plant layout information, to determine the time-dependent loads exerted by the fluid on the loops. In evaluating the hydraulic forcing functions during a postulated loss of coolant accident, the pressure and momentum flux terms are dominant. The inertia and gravitational terms are taken into account in the evaluation of the local fluid conditions in the hydraulic model.

The blowdown hydraulic analysis provides the basic information concerning the dynamic behavior of the reactor core environment for the loop forces. This requires the ability to predict the flow, quality, and pressure of the fluid throughout the reactor system. [*MULTIFLEX (Reference 6) or an equivalent computer code is used to provide this information.*]*

MULTIFLEX calculates the hydraulic transients within the entire primary coolant system. This hydraulic program considers a coupled, fluid-structure interaction by accounting for the deflection of the core support barrel. The depressurization of the system is calculated using the method of characteristics applicable to transient flow of a homogenous fluid in thermal equilibrium.

The ability to treat multiple flow branches and a large number of mesh points gives MULTIFLEX the flexibility to represent the various flow passages within the primary reactor coolant system. The system geometry is represented by a network of one-dimensional flow passages.

[*The THRUST computer program or equivalent is used to compute the transient (blowdown) hydraulic loads resulting from a loss of coolant accident.*]*

The blowdown hydraulic loads on primary loop components are computed from the equation:

$$F = 144\,A\left[(P - 14.7) + \left(\frac{\dot{m}^2}{144\,\rho\,g\,(A_m)^2}\right)\right]$$

where:

F	=	Force (lbf)
A	=	Aperture area (ft^2)
P	=	System pressure (psia)
$\dot{m}$	=	Mass flow rate (lbm/s)
ρ	=	Density (lbm/ft^3)
g	=	Gravitational constant = 32.174 ft-lbm/lbf - s2
A_m	=	Mass flow area (ft^2)

In the model to compute forcing functions, the reactor coolant loop system is represented by a model similar to that employed in the blowdown analysis. The entire loop layout is represented in a global coordinate system. Each node is described by blowdown hydraulic information and the orientation of the streamline of the force nodes in the system, which includes flow areas and projection coefficients along the three axes of the global coordinate system.

Each node is modeled as a separate control volume with one or two flow apertures associated with it. Two apertures are used to simulate a change in flow direction and area.

Each force is divided into its x, y and z components using the projection coefficients. The force components are then summed over the total number of apertures in any one node to give a total x force, a total y force, and a total z force. These thrust forces serve as input to the piping/restraint dynamic analysis.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

[*The THRUST code calculates forces the same way as the STHRUST code described in WCAP-8252 (Reference 7).*]*

3.6.2.3 Dynamic Analysis Methods to Verify Integrity and Operability

This subsection describes the pipe rupture design criteria for auxiliary piping systems. Subsection 3.6.2.2 describes the analysis methods for thrust loadings. To mitigate each postulated pipe rupture, auxiliary piping systems required to maintain pressure boundary integrity or to provide for fluid flow are identified. The loadings on these systems may consist of jet impingement loads, transient motions at terminal end connections, or internal system depressurization loadings.

The application of leak-before-break analysis eliminates evaluation of postulated pipe ruptures in the primary coolant loop piping and selected piping systems of 6-inch nominal size or larger. The piping system mechanical components and supports are designed for the effects of the remaining postulated pipe ruptures and leaks.

To confirm the continued integrity of the essential components and the engineered safety systems, consideration is given to the consequential effects of the pipe break to the extent that:

- The minimum performance capabilities of the engineered safety systems are not reduced below that required to protect against the postulated break.

- The containment leaktightness is not decreased below the design value if the break leads to a loss of coolant accident.

- Propagation of damage is limited in type or degree or both to the extent that:

  – A pipe break that is not a loss of coolant accident, steam line break, or main feedwater break will not cause a loss of coolant accident or steam line or feedwater line break. Pipe breaks on the nonreactor side of a reactor coolant system pressure boundary may be assumed to cause a failure of the reactor side of the same pipe, provided the combined failures are evaluated for impact on system performance.

  – A reactor coolant system pipe break will not cause a steam or feedwater system pipe break, and vice versa.

3.6.2.3.1 Jet Impingement

Analytical methods for the calculation of jet impingement forces are based on Moody, F. J. (Reference 5), NUREG/CR-2913 (Reference 1), and Section 7.3 of ANS-58.2-1988 (Reference 4). For piping systems this loading is a suddenly applied load that can have significant energy content. These loads are generally treated as statically applied constant loads.

Two separate structural evaluations are performed. For the short-term response, snubber supports are considered to be active and a dynamic load factor of 2 is used. For the longer-term response, snubber supports are considered inactive, and no dynamic load factor is used.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

If simplified static analysis is performed instead of a dynamic analysis, the preceding jet load (FT) is multiplied by a dynamic load factor. For an equivalent static analysis of the target structure, the jet impingement force is multiplied by a dynamic load factor of 1.2 to 2.0, depending upon the time variance of the jet load and the elastic/plastic behavior of the target. This factor assumes that the target can be represented as essentially a one-degree-of-freedom system.

3.6.2.3.2 Transient Motions at Terminal Ends

This loading is displacement limited and has a short duration of about 0.5 seconds. An example is the motions of the primary loop piping at the terminal end connection of the Class 1 pressurizer surge line piping due to a postulated pipe rupture in a Class 2 pipe connected to the steam generator.

When there are active in-line components in the piping system that must function to mitigate the postulated pipe rupture, dynamic structural analyses are performed for the terminal end motions. The calculated accelerations are evaluated to confirm the operability of the active in-line components. For piping systems with no active in-line components, static structural analyses with no dynamic amplification are performed for the terminal end motions.

These analyses may consider nonlinear geometric and material characteristics of the piping system.

3.6.2.3.3 Internal System Depressurization

This loading has a short duration of approximately 0.5 seconds and arises from rapidly traveling pressure waves in piping systems connected to the broken piping system. Two types of configurations are possible: systems without check valves and systems with check valves. In systems with check valves, the valve closure can increase the duration and magnitude of these loads.

An example of the former is the pressure waves in the Class 1 letdown line of the chemical and volume control system piping due to a postulated pipe rupture in a Class 1 pipe connected to the primary loop piping. An example of the latter is the closure of the feedwater check valve due to a postulated pipe rupture upstream of the valve.

For piping systems without closing check valves, there is little energy in the high-frequency depressurization loadings. These loadings are therefore not considered in the piping and support analysis.

For piping system with closing check valves, the magnitude of the loadings depends on the valve closure time, with shorter closing times generally causing higher loadings. For this loading the potential system failure mechanisms evaluated are: 1) excessive pipe and valve hoop stress; 2) tensile loads on the valve pressure boundary bolting; and 3) excessive distortion of the valve disc or seat.

The maximum internal pressure and the kinetic energy of the valve disc at the time of closure are used to verify the pressure boundary integrity of the piping and valve based on the preceding failure mechanisms. MULIFLEXSG is used to calculate the pressure and kinetic energy. The

supports on these systems are designed in such a way that support failure will occur prior to local pipe pressure boundary failure at the support connection.

3.6.2.3.4 Pipe Whip Restraints

To satisfy varying requirements of available space, permissible pipe deflection, and equipment operability, the restraints are designed as a combination of an energy-absorbing element and a restraint structure suitable for the geometry required to pass the restraint load from the whipping pipe to the main building structure. The restraint structure is typically a structural steel frame or truss, and the energy-absorbing element is usually either stainless steel U-bars or energy-absorbing material.

3.6.2.3.4.1 Location of Pipe Whip Restraints

For purposes of determining pipe hinge length and thus locating the pipe whip restraints, the plastic moment of the pipe is determined in the following manner:

$$Mp = 1.1\ zpSy$$

where:

zp	=	Plastic section modulus of pipe
Sy	=	Yield stress at pipe operating temperature
1.1	=	10-percent factor to account for strain hardening.

Pipe whip restraints are located as close to the axis of the reaction thrust force as practicable. Pipe whip restraints are generally located so that a plastic hinge does not form in the pipe. If, because of physical limitations, pipe whip restraints are located so that a plastic hinge can form, the consequences of the whipping pipe and the jet impingement effect are further investigated. Lateral guides are provided where necessary to predict and control pipe motion.

Generally, pipe whip restraints are designed and located with sufficient clearances between the pipe and the restraint in such a way that they do not interact and cause additional piping stresses. A design hot position gap is provided that allows maximum predicted thermal, seismic, and seismic anchor movement displacements to occur without interaction.

Exception to this general criterion may occur when a pipe support and restraint are incorporated into the same structural steel frame, or when a zero design gap is required. In these cases the pipe whip restraint is included in the piping analysis and designed to the requirements of pipe support structures.

In general, the pipe whip restraints do not prevent the access required to conduct in-service inspection examination of piping welds. When the location of the restraint makes the piping welds inaccessible for in-service inspection, a portion of the restraint is designed to be removable to provide accessibility.

3.6.2.3.4.2 Analysis and Design of Pipe Whip Restraints

The criteria for analysis and design of pipe whip restraints for postulated pipe break effects are provided in the following. These criteria are consistent with the guidelines in ANS-58.2-1988 (Reference 4).

- Pipe whip restraints are designed based on energy absorption principles by considering the elastic-plastic, strain-hardening behavior of the materials used.
- A rebound factor of 1.1 is applied to the jet thrust force.
- Except in cases where calculations are performed to verify that a plastic hinge is formed, the energy absorbed by the ruptured pipe is conservatively assumed to be zero. That is, the thrust force developed goes directly into moving the broken pipe and is not reduced by the force required to bend the pipe.
- Other structural members of the pipe whip restraints are designed for elastic response. A dynamic increase factor is used for those members that are designed to remain elastic.
- The criteria for allowable strain in a pipe whip restraint are dependent on the type of restraint. The following discussions address the types of restraints used and the allowable strain for each. Note -ε = allowable strain used in design, and δ = allowable crushable length used in design.

Stainless Steel U-Bar – This type of restraint consists of one or more U-shaped, upset-threaded rods of stainless steel looped around the pipe but not in contact with the pipe. This allows unimpeded pipe motion during seismic and thermal movement of the pipe. At rupture, the pipe moves against the U-bars, which absorb the kinetic energy of pipe motion by yielding plastically. Figure 3.6-1 shows a typical example of a U-bar restraint.

$$\varepsilon = 0.5\varepsilon u$$

where:

εu = ultimate uniform strain of stainless steel (strain at ultimate stress)

Energy-Absorbing Material – This type of restraint consists of a crushable, stainless steel, internally honeycomb-shaped element designed to yield plastically under impact of the whipping pipe. A design hot position gap is provided between the pipe and the energy-absorbing material to allow unimpeded pipe motion during seismic and thermal pipe movements. Figure 3.6-2 shows a typical example of an energy-absorbing material restraint. The allowable capacity of crushable material shall be limited to 80 percent of its rated energy dissipating capacity as determined by dynamic testing, at loading rates within ± 50 percent of the specified design loading rate. The rated energy dissipating capacity shall be taken as not greater than the area under the load-deflection curve as illustrated in Figure 3.6.2-1 of NUREG-0800, Standard Review Plan, Section 3.6.2, Revision 2.

3.6.2.4 Protective Assembly Design Criteria

In addition to pipe whip restraints, other protective devices are designed to protect against the effects of postulated pipe ruptures. Barriers and shields are designed to protect against jet impingement. Guard pipes in the break exclusion zones provide additional confidence that pipes will not leak into the annulus between the containment vessel and the shield building.

3.6.2.4.1 Jet Impingement Barriers and Shields

Barriers and shields, constructed of either steel or concrete, are provided to protect essential equipment, including instrumentation, from the effects of jet impingement resulting from postulated pipe breaks. Barriers differ from shields in that they may also accept the impact of whipping pipes. Barriers and shields include walls, floors, and structures specifically designed to provide protection from postulated pipe breaks. Barrier and shield design is based on elastic methods and the elastic-plastic methods for dynamic analysis included in Biggs, J. M. (Reference 9). Design criteria and loading combinations are according to subsections 3.8.3 and 3.8.4.

3.6.2.4.2 Auxiliary Guardpipes

The use of guard pipes has been minimized by plant arrangement and routing of high-energy piping. Guard pipes in the containment annulus areas of the break exclusion zones are designed as described in subsection 3.6.2.1.1.4. Other guard pipes are designed and constructed to the same ASME rules as the enclosed process pipe.

3.6.2.5 Evaluation of Dynamic Effects of Pipe Ruptures

The preceding information provides the criteria and methods for the evaluation of the dynamic effects of pipe ruptures. The pipe rupture hazard analysis report (also referred to as the pipe break evaluation report) includes the following:

- Prepare a stress summary
- Identify pipe break locations in high energy piping
- Identify through-wall crack locations in high and moderate energy piping
- Identify and locate essential structures, systems, and components
- Evaluate consequences of pipe whip and jet impingement

    For rooms with both high energy breaks and essential items, confirm that there is no adverse interaction between the essential items and the whipping pipe or jet.

    The plant layout is modified as required to provide separation to protect essential systems.

- Evaluate consequences of flooding, environment, and compartment pressurization

- Design and locate protective hardware

  Prepare isometric piping sketches that identify the break locations, the basis for these locations and the protective hardware which mitigates the consequences of these breaks.

- Reconciliation of as-built condition

Pipe breaks that are larger than 1 inch nominal diameter are evaluated for pipe whip and jet impingement. Lines that are located in a break exclusion zone or are qualified to leak-before-break are not evaluated for pipe whip and jet impingement effects on systems and components, except for the portions of the lines in the MSIV compartment adjacent to the main control room as noted in subsection 3.6.1.2.2.

Where these systems are qualified for mechanistic pipe break and pipe rupture loads prior to fabrication, the qualification is based on design information, not on as-built information. As-built information and the final configuration of valves and other equipment is used to verify the design analysis.

High Energy Break Locations

High energy break locations evaluated are on the nuclear island and in the turbine building for evaluation of the wall loadings in the south end of the turbine building adjacent to the main control room.

For ASME Class 1 piping terminal end locations are determined from the piping isometric drawings. Intermediate break locations depend on the ASME Code stress report fatigue analysis results. These results are not available at design certification. For the design of the AP1000, breaks are postulated at locations typically associated with a high cumulative fatigue usage factor. These locations are at valves, tees, and branch connections which have significant structural discontinuities. The Combined License applicant will evaluate these locations as part of the as-built reconciliation, (see subsection 3.6.4.1). The following ASME Class 1 lines are evaluated to terminal end and intermediate high energy break locations if applicable.

Line	**Diameter (inches)**
Pressurizer Spray	4
Automatic Depressurization Stage 1	4
Chemical and Volume Control Letdown	3
Chemical and Volume Control Makeup	3
Pressurizer Auxiliary Spray	2

For ASME Class 2 and 3 piping, terminal end break locations are determined from the piping isometric drawings. The intermediate break locations depend on the stress level. The AP1000 ASME Class 2 and 3 lines do not have intermediate breaks based on the low stress. The following ASME Class 2 and 3 lines have terminal end high energy break locations.

Line	Diameter (inches)
Main Feedwater	20
Startup Feedwater	6
Steam Generator Blowdown	4

For B31.1 piping, terminal end break locations are determined from the piping isometric drawings. The intermediate break locations in seismically analyzed pipe depend on the stress level. The AP1000 ASME seismically analyzed B31.1 piping does not have intermediate breaks based on the low stress. For nonseismically analyzed high-energy ASME B31.1, intermediate breaks locations are postulated at each fitting.

Rooms subject to pressurization due to high energy pipe break are listed in Table 3.6-2 with the terminal end location.

Essential Systems and Components

In rooms that contain high energy pipe breaks, the systems and components that are needed to mitigate the postulated break and achieve a safe plant shutdown are identified. Rooms that contain both high energy pipe break locations and essential systems or components that must be protected are listed in Table 3.6-3. No high energy pipe break protection is required in other areas of the plant.

Essential Target Evaluation

To complete the essential target evaluation jet parameters, volumetric area of affected compartments, plant layout, and separating structures are considered. Parameters that determine the shape of the jet and the magnitude of the jet and thrust loads include pressure, temperature, and friction losses between the break and the reservoir. The volumetric area affected is determined by considering jet shape and loads at the postulated location of the breaks. Where an initial evaluation of essential targets indicated adverse effects, layout may be changed to relocate the target or postulated break. If necessary, the location of whip restraints and jet shields is established to protect essential systems and components. Essential equipment protected by pipe whip restraints or jet shields is listed in Table 3.6-3. The criteria for the break location postulated for evaluation of separating structures is outlined in subsection 3.6.1.3.2.

Verification of the Pipe Break Hazard Analysis

The ASME Code, Section III, requires that each plant have a Design Report for the piping system that includes as-built information. Included in the Design Reports are the loads and loading combinations used in the analysis. Where mechanistic pipe break requirements are used to eliminate the evaluation of dynamic effects of pipe rupture in ASME Code, Section III, Class 1, 2, and 3 piping system, the basis for the exclusion is documented in the Design Report.

To support design certification, the pipe rupture hazard analysis is complete except for the final piping stress analyses, pipe whip restraint design, and as-built reconciliation. The final piping stress analyses, pipe whip restraint design, and as-built reconciliation of the pipe break hazard analysis is addressed by the Combined License applicant. The as-built reconciliation includes

evaluation of the ASME Code fatigue analysis, pipe break dynamic loads, reconciliation to the certified design floor response spectra, confirmation of the reactor coolant loop time history seismic analyses, changes in support locations, preoperational testing, and construction deviations.

3.6.2.6 Evaluation of Flooding Effects from Pipe Failures

The effect of flooding due to high and moderate energy pipe failures on essential systems and components is described in Section 3.4.

3.6.2.7 Evaluation of Spray Effects from High- and Moderate-Energy Through-Wall Cracks

Essential systems and components are evaluated for the potential effects of spray from high- and moderate-energy through-wall cracks. Spray effects are assumed to be limited to the compartment where the pipe failure occurs. The spray is assumed to wet unprotected components in the compartment. It is further assumed the spray does not damage non-electrical passive components, including piping, ducts, valve bodies, or mechanical components of valve operators. Spray may cause failure of electrical components not designed to withstand wetting. Components protected by NEMA 4 or NEMA 12 enclosures are not affected by spray effects.

The safe shutdown components inside containment are subject to wetting from design basis events inside containment. These conditions bound the effects of spray from moderate energy cracks. Sensitive components are qualified for this environment as described in Section 3.11.

The doors to the auxiliary Class 1E battery rooms are normally closed, so spray cannot affect the batteries if fire fighting activities or a pipe crack were to occur in the corridor. If fire fighting activities were to occur in a particular room, all of the equipment is assumed inoperable due to the fire, therefore, no further spray effects need be considered. The containment isolation valves subject to spray and the safe shutdown components in the main steam tunnels are provided with spray protection. The sensitive components of the main control room emergency habitability system are protected from spray effects.

3.6.3 Leak-before-Break Evaluation Procedures

This subsection describes the design basis for mechanistic pipe break (leak-before-break) evaluation of high-energy piping systems.

Mechanistic pipe break evaluations demonstrate that for piping lines meeting the criteria, sudden catastrophic failure of the pipe is not credible. It is demonstrated that piping that satisfies the criteria leaks at a detectable rate from postulated flaws prior to growth of the flaw to a size that would fail because applied loads resulting from normal conditions, anticipated transients, and a postulated safe shutdown earthquake.

The use of mechanistic pipe break criteria represents a higher level of confidence of the integrity of piping systems based on additional criteria compared to the existing high level of integrity provided by the requirements of the ASME Code. Evaluations of the mechanistic pipe break criteria are commonly called leak-before-break evaluations.

The use of mechanistic pipe break criteria permits the elimination of the evaluation of dynamic effects of sudden circumferential and longitudinal pipe breaks in the design basis analysis of structures, systems, and components. General Design Criterion 4 of Appendix A, 10 CFR Part 50 allows the use of analyses to eliminate from the design basis the dynamic effects of pipe ruptures.

Without the application of mechanistic pipe break criteria, the dynamic effects are evaluated for pipe ruptures postulated at locations defined in subsection 3.6.2. Dynamic effects include jet impingement, pipe whip, jet reaction forces on other portions of the piping and components, subcompartment pressurization including reactor cavity asymmetric pressurization transients, pump overspeed and traveling pressure waves from the depressurization of the system.

Incorporating leak-before-break criteria and guidelines into the design process maximizes the benefits of applying mechanistic pipe break. Eliminating the dynamic effects permits minimizing the size and number of protective structures and eliminates the use of pipe whip restraints. This permits design optimization and avoids obstruction of pipe welds for in-service inspection by protective structures and restraints.

High-energy ASME Code Section III piping that is evaluated to the leak-before-break criteria is identified in Appendix 3E. This applies to the main steam piping as follows. The main steam piping from the steam generator outlet nozzle to the anchor downstream of the isolation valve is analyzed for applicable loadings including the safe shutdown earthquake. This anchor is at the exterior wall of the auxiliary building. The portion of this piping from the containment penetration flued head inboard weld to the above anchor satisfies the break exclusion zone requirements described in subsection 3.6.2. The portion of this piping from the steam generator outlet nozzle to flued head inboard weld is evaluated to the leak-before-break criteria. High-energy piping that does not satisfy the leak-before-break criteria is designed to the requirements discussed in subsections 3.6.1 and 3.6.2.

The piping to which mechanistic pipe break is applied is analyzed to demonstrate that the piping has leak-before-break characteristics. The leak-before-break analysis is either a fracture-mechanics based stability analysis or a plastic-instability limit load analysis as appropriate. The analysis combines normal and abnormal (including seismic) loads to determine a critical crack size for a postulated through-wall crack. The critical crack size is compared to the size of a leakage crack for which, with appropriate margin, detection is certain. When the critical crack size is sufficiently larger than the leakage crack size the leak-before-break requirements are satisfied.

Mechanistic pipe break is not used for purposes of specifying non-structural design criteria for emergency core cooling, containment systems, or other non-structural engineered safety features, or for the evaluation of environmental effects including spray wetting, humidity, and adverse reactions with chemicals in the coolant. This includes piping for which leak-before-break is demonstrated.

A bounding analysis is performed for each piping system. The bounding analysis is used by the Combined License applicant to verify that the as-built piping satisfies the requirements for leak-before-break.

3.6.3.1 Application of Mechanistic Pipe Break Criteria

Piping systems to which mechanistic pipe break are applied are high integrity systems with well understood loading combinations and conditions. The piping systems to which it is applied satisfy the requirements of the ASME Code, Section III. ASME Code requirements also apply to the pre-service and in-service inspection which confirm continued integrity.

The mechanistic pipe break approach is applicable to high-energy piping provided plant design, operating experience, tests, or analyses have indicated low probability of failure from effects of intergranular stress corrosion cracking, water hammer, steam hammer, fatigue (thermal or mechanical), or erosion.

The plant design and operating features permit the application of the mechanistic pipe break approach. The piping to which the leak-before-break criteria is applied is evaluated for fatigue due to cyclic loads as required by the appropriate requirements of the ASME Code.

The piping in the AP1000 does not operate at temperatures for which creep or creep fatigue must be considered.

The reactor coolant loop piping, branch lines, and other lines in contact with reactor coolant are fabricated of austenitic stainless steel, which is very resistant to erosion and corrosion in typical reactor coolant chemistries and flow rates. Intergranular stress corrosion cracking has not been associated with reactor coolant piping in pressurized water reactors.

The design of the reactor coolant loop is not conducive to the generation of water hammer loads. The reactor coolant loop does not have any valves that could result in a water hammer due to rapid valve closure. The steam bubble in the pressurizer is not subject to the introduction of a large volume of cold water sufficient to result in a bubble collapse water hammer.

The design and component selection of reactor coolant branch lines and other lines evaluated for mechanistic pipe break follow design guidelines intended to minimize the potential for water hammer. Comparison of the AP1000 piping to the screening criteria in Subsection 5.29 of NUREG/CR-6519 (Reference 13) demonstrates that there is not a significant potential for water hammer in the leak-before-break piping.

Thermal stratification of water in stagnant or slowly flowing lines can result in thermal fatigue in a pipe. The piping and system design requirements for AP1000 address the potential for thermal stratification. For additional information of thermal stratification, see subsections 3.9.3, 5.4.3, and 5.4.5.

The water chemistry and flow velocities in the main steam lines are controlled to minimize the potential for erosion and corrosion. At full power the flow rate in the main steam line is approximately equal to the nuclear industry criteria for steam velocity in advanced light water reactors of 150 ft./sec. The main steam lines are not subject to water hammer or thermal stratification by the nature of the fluid transported.

The steam line is protected from being filled with water due to steam generator overfill by implementation of operating instructions or isolation requirements included in the protection

system logic or both. See Section 7.3 for information on the protection system design to prevent overfill.

In addition to requirements on the design, fabrication, and inspection of the piping systems, the application of mechanistic pipe break requires a qualified leak detection capability. Leak detection systems inside containment meet the guidelines of Regulatory Guide 1.45. See subsection 5.2.5 for a discussion of the leak detection system for the reactor coolant system and connected piping.

3.6.3.2 Design Criteria for Leak-before-Break

The methods and criteria to evaluate leak-before-break in the AP1000 are consistent with the guidance in NUREG-1061 (Reference 11) and Draft Standard Review Plan 3.6.3 (Reference 12). The application of the mechanistic pipe break in AP1000 requires that the following design requirements are met.

- Pre-service inspection of welds is required.

- For ASME Code Class 1, Class 2, and Class 3 systems for which leak-before break is demonstrated, the ASME Code, Section III and Section XI preservice and inservice inspection requirements will provide for the integrity of each system. The weld and welder qualification, and weld inspection requirements for ASME Code, Section III, Class 3 leak-before-break lines are equivalent to the requirements for Class 2. The inservice inspection requirement for each Class 3 leak-before-break line includes a volumetric inspection equivalent to the requirements for Class 2 for the weld at or closest to the high stress location.

- Inservice inspection and testing of snubbers (if used) are performed to provide for a low snubber failure rate.

- For the maximum stress due to steady-state vibration refer to subsection 3.9.2.

- The leak-before-break bounding analysis curves are developed for each applicable piping system. The bounding analysis methods are described in Appendix 3B. These curves give the design guidance to satisfy the stress limits and leak-before-break acceptance criteria. The highest stressed point (critical location) determined from the piping stress analysis is compared to the bounding analysis curve and has to fall on or under the curve. The points on or under the bounding analysis curve satisfy the requirements for leak-before-break.

  The analyzed normal stress and maximum stress are not required to construct the bounding analysis curve. The analyzed stresses are calculated by the equation;

$$\sigma = \frac{F_x}{A} + \frac{M}{Z}$$

where:

σ is the stress
F_x is the axial force
M is the applied moment
A is the piping cross-sectional area
Z is the piping section modulus.

The normal stress is calculated by the algebraic summation of load combination method and the maximum stress is calculated by the absolute summation of load combination method.

- The corrosion-resistant piping materials, including base metal and welds, have an appropriate toughness. The piping materials containing primary coolant are wrought stainless steel. The welds in stainless steel pipe are made using the gas tungsten arc (GTAW) process. These materials are very resistant to crack extension. The tensile properties for the leak-before-break evaluation are those found in the Section II Appendices of the ASME Code. During the design stage, the material properties used are based on the ASME Code minimum values. During the as-built reconciliation stage, certified material test report values are reviewed to verify that ASME Code requirements are satisfied.

- For those lines fabricated using non-stainless ferritic materials, the materials used and the associated welds have adequate toughness to demonstrate that leak-before-break criteria are satisfied. The welds are made using the gas tungsten arc (GTAW) process. The tensile properties for the leak-before-break evaluation are obtained from actual material tests. During the design stage, the material properties are based on test results. During the as-built reconciliation stage, certified material test report values are reviewed to verify that the toughness and strength requirements of the ASME Code, Section III are satisfied.

- Potential degradation by erosion, erosion/corrosion and erosion cavitation is examined to provide low probability of pipe failure.

- Wall thicknesses in elbows and other fittings are evaluated to confirm that ASME Code, Section III piping requirements are met as a minimum.

- The as-built condition of the piping and support system is evaluated based on the guidelines in EPRI NP-5630 (Reference 10) and reconciled to the analysis of the leak-before-break criteria based on the design information. The locations and characteristics of the supports, including any gaps between the supports and piping, or other configurations that result in a nonlinear response are included in the as-built evaluation.

- Adjacent structures and components are designed for the safe shutdown earthquake event to provide low probability of indirect pipe failure.

- The piping supports are anchored to reinforced concrete structures, to concrete-filled steel plate structures, or to steel structures anchored to these types of structures. Piping is not supported by masonry block walls.

3.6.3.3 Analysis Methods and Criteria

The methods used to develop the bounding analysis curves are described in Appendix 3B. Development of the bounding analysis curves provides an evaluation method that is consistent with NRC requirements and guidance. The calculation method and computer codes used for AP1000 are benchmarked to test data and has been previously accepted by the NRC for leak-before-break evaluations in operating nuclear power plants.

Analyzable sections run from one terminal end or anchor to another terminal end or anchor. A terminal end is typically a connection to a larger pipe or a component. For the structural analysis, a normally closed valve between pressurized and unpressurized portions of a line is not considered a terminal end. Figure 3.6-3 is a schematic of a portion of a piping system that illustrates the meaning of analyzable segments. In the figure the analyzable portion of the pipe runs from point A to point D.

The leak-before-break evaluation is based on a fracture mechanics stability analysis comparing the selected leakage crack to the critical crack size. The following discussion outlines the analysis method.

The development of leak-before-break bounding analysis curves assume that circumferentially oriented postulated cracks are limiting. Stability is established by analyzing through-wall flaws.

Leakage Flaw

Through-wall flaws in candidate leak-before break piping systems are postulated. [*The size of the postulated flaws are large enough so that the leakage is detectable with adequate margin, using 10 times the minimum installed leak detection capability when the pipes are subjected to normal operational loads combining by algebraic sum method.*]* That is, the size of the leakage flaw postulated would be expected to have a leak rate 10 times the size of the rated leak rate detection capability.

As noted in subsection 5.2.5, the rated capability of the leak detection systems for the primary coolant inside containment is 0.5 gpm in one hour. The methods used to detect leakage are described in subsection 5.2.5.3. The methods used for primary coolant are the containment sump level, inventory balance, and containment atmosphere radiation. The method used to detect leakage from the main steam line inside containment is the containment sump level. Containment air cooler condensate flow, and containment atmosphere pressure, temperature, and humidity also provide an indication of possible leakage.

Stability and Critical Flaw Sizes

The local and global failure mechanisms are evaluated, as appropriate, to provide margin on flaw size and load. The local mode of failure addresses crack tip behavior: blunting, initiation, extension, and instability. The local failure mechanism is evaluated for ferritic steel piping systems using the J-integral method. The global mode of failure addresses the behavior of the net section: initial yielding, strain hardening, and plastic hinge formation. The global failure mechanism (limit load method) is evaluated for stainless steel piping with no cast material and

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

GTAW welding. From these evaluations a critical crack size is determined. That is, a crack larger than the critical crack size would have unstable growth characteristics.

Acceptance Standards

[*The results of the preceding evaluations are compared to show that the critical flaw size, which is shown to be stable when the maximum loads are combined based on individual absolute values, is at least twice the size (to satisfy margin of 2 on flaw size) of the leakage flaw size. To satisfy a margin on load of 1.0, the maximum loads are combined using absolute summation of individual values.*]* The maximum loads are described in Appendix 3B subsection 3B.3.3.

Bounding Analyses

Evaluations are provided for each different combination of material type, pipe size, pressure, and temperature. These evaluations are used to develop a set of curves of maximum faulted stress versus the corresponding normal stress that satisfy the criteria for leak-before-break. These curves are used in the design of the piping systems and will be used by the Combined License applicant to verify that the as-built piping satisfies the requirements for leak-before-break.

3.6.3.4 Documentation of Leak-before-Break Evaluations

The leak-before-break evaluation is used to support the elimination of dynamic effects of pipe breaks from the loading conditions for the piping analysis. An evaluation of leak-before-break using the as-built configuration of the piping system and supports is required as part of the Design Report (also referred to as LBB evaluation report where applicable) of the as-built configuration required to meet ASME Code requirements and LBB criteria. Appendix 3B contains a discussion of the bounding analysis methods for the leak-before-break evaluation.

The analysis methods, criteria, and loads used for evaluation of stress in piping systems are outlined in subsections 3.7.3 and 3.9.3.

3.6.4 Combined License Information

3.6.4.1 Pipe Break Hazard Analysis

Combined License applicants referencing the AP1000 certified design will complete the final pipe whip restraint design and address as built reconciliation of the pipe break hazards analysis in accordance with the criteria outlined in subsections 3.6.1.3.2 and 3.6.2.5. The as-built pipe rupture hazard analysis will be documented in an as-built Pipe Rupture Hazards Analysis Report.

3.6.4.2 Leak-before-Break Evaluation of as-Designed Piping

Combined License applicants referencing the AP1000 certified design will complete the leak-before-break evaluation by comparing the results of the as-designed piping stress analysis with the bounding analysis curves documented in Appendix 3B. The Combined License applicant may perform leak-before-break evaluation for a specific location and loading for cases not covered by the bounding analysis curves. Successfully satisfying the bounding analysis curve limits in Appendix 3B may necessitate lowering the detection limit for unidentified leakage in containment

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

from 0.5 gpm to 0.25 gpm. If so, the Combined License applicant shall provide a leak detection system capable of detecting a 0.25 gpm leak within 1 hour and shall modify appropriate portions of the DCD including subsections 5.2.5, 3.6.3.3, 11.2.4.1, Technical Specification 3.4.7 (and Bases), Technical Specification Bases B3.4.9, and Technical Specification 3.7.8 (and Bases). The leak-before-break evaluation will be documented in a leak-before-break evaluation report.

3.6.4.3 Leak-before-Break Evaluation of as-Built Piping

Combined License applicants referencing the AP1000 certified design will address: 1) verification that the as-built stresses, diameter, wall thickness, material, welding process, pressure, and temperature in the piping excluded from consideration of the dynamic effects of pipe break are bounded by the leak-before-break bounding analysis; 2) a review of the Certified Material Test Reports or Certifications from the Material Manufacturer to verify that the ASME Code, Section III strength and Charpy toughness requirements are satisfied; and 3) complete the leak-before-break evaluation by comparing the results of the final piping stress analysis with the bounding analysis curves documented in Appendix 3B. The leak-before-break evaluation will be documented in a leak-before-break evaluation report.

3.6.4.4 Primary System Inspection Program for Leak-before-Break Piping

Combined License applicants referencing the AP1000 certified design will develop an inspection program for piping systems qualified for leak-before-break. The inspection program will consider the operating experience of the materials used in the AP1000 piping systems qualified for leak-before-break, and will include augmented inspection plans and evaluation criteria consistent with those measures imposed on or adopted by operating PWRs as part of the ongoing resolution of concerns regarding the potential for PWSCC in operating plants. The AP1000 inspection program will be consistent with the inspection program adopted for operating PWRs that use Alloy 690, 52, and 152 in approved leak-before-break applications.

3.6.5 References

1. NUREG/CR-2913, “Two-Phase Jet Loads,” January 1983.

2. WCAP-8077 (Proprietary) and WCAP-8078 (Nonproprietary), “Ice Condenser Containment Pressure Transient Analysis Methods,” March 1973.

3. ASME/ANSI-B31.1, Code for Power Piping, 1989 Addenda to 1989 Edition.

4. ANSI/ANS-58.2-1988, “Design Bases for Protection of Light Water Nuclear Power Plants Against Effects of Postulated Pipe Rupture.”

5. Moody, F. J., Fluid Reaction and Impingement Loads, paper presented at the ASCE Specialty Conference, Chicago, December 1973.

6. “MULTIFLEX, A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics,” WCAP-8708 (Proprietary) and WCAP-8709 (Nonproprietary), February 1976.

7. WCAP-8252, "Documentation of Selected Westinghouse Structural Analysis Computer Codes," Revision 1, May 1977.

8. Deleted

9. Biggs, J. M., Introduction to Structural Dynamics, McGraw-Hill Book Company, New York, 1964.

10. EPRI NP-5630, "Guidelines for Piping System Reconciliation" (NCIG-05, Revision 1), May 1988.

11. NUREG-1061, Volume 3, Report of the U. S. Nuclear Regulatory Commission Piping Review Committee, Evaluation of Potential for Pipe Breaks, November 1984.

12. Standard Review Plan 3.6.3, "Leak Before Break Evaluation Procedures," Federal Register, Volume 52, Number 167, Friday, August 28, 1987; Notice (Public Comment Solicited), pp. 32626-32633.

13. NUREG/CR-6519, Screening Reactor Steam/Water Systems for Water Hammer, November 1996.

Table 3.6-1

HIGH-ENERGY AND MODERATE-ENERGY FLUID SYSTEMS CONSIDERED FOR PROTECTION OF ESSENTIAL SYSTEMS[a]

System	High-Energy	Moderate-Energy
Reactor coolant (RCS)	•	
Steam generator (SGS)[b]	•	
Passive core cooling (PXS)	•	
Passive containment cooling (PCS)[c]		•
Main control room habitability (VES)	•	
Chemical and volume control (CVS)	•	
Primary sampling (PSS)	•	
Compressed and instrument air (CAS)		•
Normal residual heat removal (RNS)[a]		•
Component cooling water (CCS)		•
Spent fuel pit cooling (SFS)		•
Demineralized water (DWS)		•
Liquid radwaste (WLS)		•
Radioactive drain (WRS)		•
Central chilled water (VWS)[a]		•
Fire protection (FPS)		•
Steam generator blowdown (BDS)[d]	•	
Main and startup feedwater (FWS)[d]	•	
Main steam (MSS)[d]	•	
Hot water heating (VYS)	•	

Notes:

a. Systems included on this list are high-energy or moderate-energy fluid systems located in the containment or the auxiliary building. Systems that operate at or close to atmospheric pressure such as ventilation and gravity drains are not included. The normal residual heat removal system lines are classified as moderate-energy based on the 1 percent rule. These lines experience high-energy conditions for less than 1 percent of the plant operating time. The portions of the normal residual heat removal system from the connections to the reactor coolant system and passive core cooling system to the first closed valve in each line are high energy. The spent fuel pit cooling system and central chilled water system inside containment and through the containment penetration to the connection with the hot water heating system are classified as moderate energy based on the 2 percent rule. These systems experience high-energy conditions for less than 2 percent of the system operating time. See subsection 3.6.1.1 Item A and subsection 3.6.1.2 for additional information.

b. Main and startup feedwater, main steam, and steam generator blowdown lines located in the containment and auxiliary building are part of the steam generator system.

c. The essential portion of the system is at atmospheric pressure.

d. The portion of these systems in the turbine building adjacent to the auxiliary building are evaluated for the effect of a circumferential or longitudinal break on the main control room.

Table 3.6-2 (Page 1 of 7)

SUBCOMPARTMENTS AND POSTULATED PIPE RUPTURES

Compartment		Lines Evaluated to LBB		Lines Not Evaluated to LBB	
Name	**Room Number**	**Description**	**Terminal End Break Location Excluded by LBB**	**Description**	**Terminal End Break Location**
Steam Generator Compart-ment 1	11201	22 in. Cold Leg (RCS)	RC Pump Nozzles (2)	4 in. Pressurizer Spray (RCS)	Cold Leg Nozzles (2)
		18 in. Fourth Stage ADS (RCS)	Hot Leg Nozzle		
	11301	31 in. Hot Leg (RCS)	SG Nozzle	3 in. Purification (CVS)	3 in. SG Channel Head Nozzle
		18 in. Surge Line (RCS)	Hot Leg Nozzle		
		18 in. & 14 in. Fourth Stage ADS (RCS)	Valves: V004A/C		
		14 in. PRHR Return (RCS)	SG Channel Head Nozzle		
	11401	None		4 in. SG Blowdown (SGS)	4 in. SG Nozzle
	11501	None		None	
	11601			20 in. Feedwater (SGS) 6 in. Startup Feedwater (SGS)	SG Nozzle SG Nozzle
	11701	38 in. Main Steam (SGS)	SG Nozzle	None	

Table 3.6-2 (Page 2 of 7)

SUBCOMPARTMENTS AND POSTULATED PIPE RUPTURES

Compartment		Lines Evaluated to LBB		Lines Not Evaluated to LBB	
Name	**Room Number**	**Description**	**Terminal End Break Location Excluded by LBB**	**Description**	**Terminal End Break Location**
Steam Generator Compart-ment 2	11202	22 in. Cold Leg (RCS)	RC Pump Nozzles (2)	None	
		18 in. Fourth Stage ADS (RCS)	Hot Leg Nozzle		
		20 in. Normal RHR (RCS)	Hot Leg Nozzle		
		12 in. Normal RHR (RCS)	20 in. x 12 in. Reducer (This is not a terminal end)		
	11302	31 in. Hot Leg (RCS)	SG Nozzle	None	
		18 in. & 14 in. Fourth Stage ADS (RCS)	Valves: V004B/D		
		8 in. Cold Leg to CMT (RCS)	Cold Leg Nozzles (2)		
	11402	None		4 in. SG Blowdown (SGS)	4 in. SG Nozzle
	11502	None		None	
	11602			20 in. Feedwater (SGS) 6 in. Startup Feedwater (SGS)	SG Nozzle SG Nozzle
	11702	38 in. Main Steam (SGS)	SG Nozzle	None	
Reactor Vessel Nozzle Area	11205	31 in. Hot Leg (RCS)	Reactor Vessel Nozzles (2)	None	
		22 in. Cold Leg (RCS)	Reactor Vessel Nozzles (4)		
		8 in. Direct Vessel Injection (RCS)	Reactor Vessel Nozzles (2)		

Table 3.6-2 (Page 3 of 7)

SUBCOMPARTMENTS AND POSTULATED PIPE RUPTURES

Compartment		Lines Evaluated to LBB		Lines Not Evaluated to LBB	
Name	**Room Number**	**Description**	**Terminal End Break Location Excluded by LBB**	**Description**	**Terminal End Break Location**
PXS Valve and Accumulator Room A	11206	8 in. Accumulator Injection (PXS)	Accumulator Nozzle	None	
		8 in. CMT Injection (PXS)	CMT Nozzle		
		6 in. Line from Normal RHR (RNS)	Valve: V017A		
		8 in. Line from IRWST (PXS)	Valves: V125A & V123A		
PXS Valve Room B	11207 PXS	6 in. Line from Normal RHR (RNS)	Valve: V017B	None	
		8 in. Line from IRWST (PXS)	Valves: V125B & V123B		
Accumulator Room B	11207 ACCUM	8 in. Accumulator Injection (PXS)	Accumulator Nozzle	None	
		8 in. CMT Injection (PXS)	CMT Nozzle		
Vertical Access	11204	None		3 in. Line from Regen HX to SG 01 (CVS)	Anchor to Wall
				3 in. Purification from Cold Leg to Regen HX (CVS)	Anchor to Wall
RNS Valve Room	11208	10 in. Normal RHR (RNS)	Valves: V001A/B	None	

Table 3.6-2 (Page 4 of 7)

SUBCOMPARTMENTS AND POSTULATED PIPE RUPTURES

Compartment		Lines Evaluated to LBB		Lines Not Evaluated to LBB	
Name	**Room Number**	**Description**	**Terminal End Break Location Excluded by LBB**	**Description**	**Terminal End Break Location**
Lower Pressurizer Compartment	11303	18 in. Surge Line (RCS)	Pressurizer Nozzle	None	
Upper Pressurizer Compartment	11503	14 in. ADS (RCS)	Pressurizer Nozzle (2)	4 in. Pressurizer Spray (RCS)	Pressurizer Nozzle
Lower ADS Valve Area	11603	14 in. & 8 in. ADS (RCS) 6 in. Pressurizer Safety (RCS)	Valves: V012B & V013B 14 in. x 6 in. Tee, Valve-V005B	4 in. ADS (RCS)	Valve V0011B & 14 in. x 4 in. Branch
Upper ADS Valve Area	11703	14 in. & 8 in., ADS (RCS) 6 in. Pressurizer Safety (RCS)	Valves: V012A & V013A 14 in. x 6 in. Tee, Valve-V005A	4 in. ADS (RCS)	Valve V0011A & 14 in. x 4 in. Branch
Maintenance Floor/ Mezzanine	11400	38 in. Main Steam (SGS)	Non-terminal End Location (2) at Boundary of Break Exclusion Zone	6 in. Startup Feedwater (SGS)	Anchors (2) at Containment Penetration
		14 in. Passive RHR (PXS)	PRHR HX Inlet Nozzle		
		8 in. CMT Balance Line Piping	CMT Nozzles (2)		

Table 3.6-2 (Page 5 of 7)

SUBCOMPARTMENTS AND POSTULATED PIPE RUPTURES

Compartment		Lines Evaluated to LBB		Lines Not Evaluated to LBB	
Name	**Room Number**	**Description**	**Terminal End Break Location Excluded by LBB**	**Description**	**Terminal End Break Location**
SG01 Access Room	11304	None		None	
Pressurizer Spray Valve Room	11403	None		4 in. Pressurizer Spray (RCS)	Anchor (both sides)
Maintenance Floor	11300	14 in. Passive RHR (PXS)	PRHR HX Outlet Nozzle	None	
Operating Deck	11500	None		None	
CVS Room	11209	None		3 in. Purification from Pressurizer Spray to Regen HX (CVS)	Regen HX Nozzle
				3 in. Return, Auxiliary Spray (CVS)	Regen HX Nozzle
				3 in. Return to RNS from Regen HX (CVS)	Valve: V079
				3 in. Supply from RNS to Letdown HX (CVS)	Valve: V072
				3 in. Supply from Regen HX to Letdown HX (CVS)	Nozzles: Regen HX, Letdown HX
CVS Room	11209 Pipe Chase	None		3 in. Purification from Anchor to Regen HX	Anchor
				3 in. Return from Regen HX to Anchor (CVS)	Anchor
				4 in. SG Blowdown (SGS)	Anchors (2) at Containment Penetration

Table 3.6-2 (Page 6 of 7)

SUBCOMPARTMENTS AND POSTULATED PIPE RUPTURES

Compartment		Lines Evaluated to LBB		Lines Not Evaluated to LBB	
Name	**Room Number**	**Description**	**Terminal End Break Location Excluded by LBB**	**Description**	**Terminal End Break Location**
Reactor Coolant Drain Tank Room	11104	None		None	
Reactor Vessel Cavity	11105	None		None	
MSIV Compartment B	12504/ 12404	None		Main Steam Main Feedwater Startup Feedwater Lines[(a)]	Longitudinal Cracks with Crack Flow Areas of 1 Square Foot are Postulated
MSIV Compartment A	12506/ 12406	None		Main Steam Main Feedwater Startup Feedwater Lines[(a)]	Longitudinal Cracks with Crack Flow Areas of 1 Square Foot are Postulated
Valve/Piping Penetration Room	12306	None		4 in. Steam Generator Blowdown[(a)]	Anchors (2) at Containment Penetrations Anchors (2) at Wall to Turbine Building

Note:

a. The piping in these areas is included in break exclusion zones. For additional information on the evaluation of these lines, see subsection 3.6.1.2.1 for the steam generator blowdown line; subsection 3.6.1.2.2 for information on the evaluation of lines in MSIV compartment B because of the proximity to the main control room; and subsection 3.6.2.1.1.4 for general break exclusion zone requirements.

Table 3.6-2 (Page 7 of 7)

SUBCOMPARTMENTS AND POSTULATED PIPE RUPTURES

Room #	Description	Bottom Elevation	Top Elevation
11104	RCDT Room	66′-6″	81′-0″
11105	Reactor Vessel Cavity	66′-6″	98′
11205	Reactor Vessel Nozzle Area	98′	107′-2″
11201	SG Compartment 1	83′	104′-7″
11202	SG Compartment 2	83′	104′-7″
11204	Vertical Access	83′	107′-2″
11206	PXS Valve Room A	87′-6″	105′-2″
11300	Maintenance Floor	107′-2″	118′-6″
11301	SG Compartment 1	104′-7″	116′-6″
11302	SG Compartment 2	104′-7″	116′-6″
11400	Maintenance Floor/Mezzanine	118′-6″	135′-3″
11401	SG Compartment 1	116′-6″	135′-3″
11402	SG Compartment 2	116′-6″	135′-3″
11501	SG Compartment 1	135′-3″	153′-0″
11502	SG Compartment 2	135′-3″	153′-0″
11601	SG Compartment 1	153′-0″	166′-4″
11602	SG Compartment 2	153′-0″	166′-6″
11701	SG Compartment 1	166′-4″	----
11702	SG Compartment 2	166′-4″	----
11500	Operating Deck	135′-3″	281′-8 3/8″
11303	Pressurizer Lower Compartment	107′-2″	135′-3″
11304	SG01 Access Room	107′-2″	118′-6″
11403	Pressurizer Spray Valve Room	118′-6″	135′-3″
11503	Pressurizer Upper Compartment	135′-3″	174′-4″
11603	Lower ADS Valve Area	174′-4″	185′-1″
11703	Upper ADS Valve Area	185′-1″	----
11207 ACCUM	Accumulator Room B	87′-6″	105′-2″
11207 PXS	PXS Valve Room B	87′-6″	105′-2″
11208	RNS Valve Room	94′	105′-2″
11209	CVS Room	80′-6″	105′-2″
11209 PIPE	CVS Room Pipe Tunnel	100′-0″	105′-2″
12306	Valve/Piping Penetration Room	100′-0″	117′-6″
12504/12404	MSIV Compartment B (Upper/Lower)	117′-6″	153′-0″
12506/12406	MSIV Compartment A (Upper/Lower)	117′-6″	153′-0″

Table 3.6-3 (Sheet 1 of 2)

NI ROOMS WITH POSTULATED HIGH ENERGY LINE BREAKS/ESSENTIAL TARGETS/PIPE WHIP RESTRAINTS AND RELATED HAZARD SOURCE

Room Number	Room Description	Essential Target Description	Hazard Source
11201	Steam Generator Compartment-01	Automatic depressurization system (ADS) Stage 4 valves (RCS-V004A, RCS-V004C, RCS-V014A, and RCS-V014C	1) Reactor Coolant System (RCS)-Pressurizer Spray Line, 4" L110A: Terminal End Break at RCS Cold Leg L002A 2) RCS-Pressurizer Spray Line, 4" L106: Terminal End Break at RCS Cold Leg L002B
11209	Pipe Chase to CVS Equipment Room	CVS makeup, CVS letdown, CVS hydrogen supply, and SGS steam generator blowdown piping	1) Steam Generator System (SGS)-Blowdown Line, 4" L009A: Terminal End Break at Containment Penetration P27 2) SGS-Blowdown Line, 4" L009B: Terminal End Break at Containment Penetration P28 3) CVS-Makeup Line, 3" L056: Terminal End Break at In-Line Anchor
11303	Lower Pressurizer Compartment	SGS steam generator blowdown and steam generator drain piping. RCS pressurizer pressure and level instrumentation; pressurizer support steel	1) RCS-CVS Purification Line, 3" L112: Intermediate Break at Outlet to Valve CVS-V082
11400	Maintenance Floor Mezzanine	Steam generator supports	1) SGS-Startup Feedwater Line, 6" L005B: Terminal End Break at Containment Penetration P45
11401	Steam Generator 01 Compartment	ADS Stage 4 valves (RCS-V004A, RCS-V004C, RCS-V014A, and RCS-V014C)	1) RCS Pressurizer Spray Line, 4" L106: Terminal End Break at In-Line Anchor
11403	Pressurizer Spray Valve Room	ADS Stage 4 valves (RCS-V004A, RCS-V004C, RCS-V014A, and RCS-V014C)	1) RCS Pressurizer Spray Line, 4" L213: Intermediate Break at 4x2 Tee Connection to Auxiliary Spray Line 2) RCS CVS Letdown Line, 3" L111: Intermediate Break at Inlet to Valve CVS-V001

Table 3.6-3 (Sheet 2 of 2)

NI ROOMS WITH POSTULATED HIGH ENERGY LINE BREAKS/ESSENTIAL TARGETS/PIPE WHIP RESTRAINTS AND RELATED HAZARD SOURCE

Room Number	Room Description	Essential Target Description	Hazard Source
11503	Upper Pressurizer Compartment	ADS Stage 1, 2, and 3 valves, lower tier platform support steel	1) RCS-Pressurizer Spray Line, 4" L215: Terminal End Break at Pressurizer Nozzle
11601	Steam Generator-01 Feed Water Nozzle Area	RCS head vent piping/valves SGS level instrumentation piping	1) SGS-Startup Feedwater Line, 6" L005A: Terminal End Break at Steam Generator MB01 Nozzle 2) SGS-Main Feedwater Line, 20" L003A: Terminal End Break at Steam Generator MB01 20" x 16" Reducing Nozzle
11602	Steam Generator-02 Feedwater Nozzle Area	SGS level instrumentation piping	1) SGS-Main Feedwater line, 20" L003B: Terminal End Break at Steam Generator MB02 20" x 16" Reducing Nozzle
11603	Lower ADS Valve Area	ADS Stage 2 and 3 valves (RCS-V002B, RCS-V003B, RCS-V012B, and RCS-V013B) Raceways and cable for Divisions A/C and B/D	1) RCS-Automatic Depressurization System Stage 1 Line, 4" L010B: Terminal End Break at Inlet to Valve RCS V011B
11703	Upper ADS Valve Area	ADS Stage 2 and 3 valves (RCS-V002A, RCS-V003A, RCS-V012A, and RCS-V013A) Raceways and cables for Division A/C	1) RCS-Automatic Depressurization System Stage 1 Line, 4" L010A: Terminal End Break at Inlet to Valve RCS V011A
12244	Lower Annulus Valve Area	CVS Makeup valve CVS-V090	1) CVS-Makeup Line, 3" L131: Terminal End at In-Line Anchor

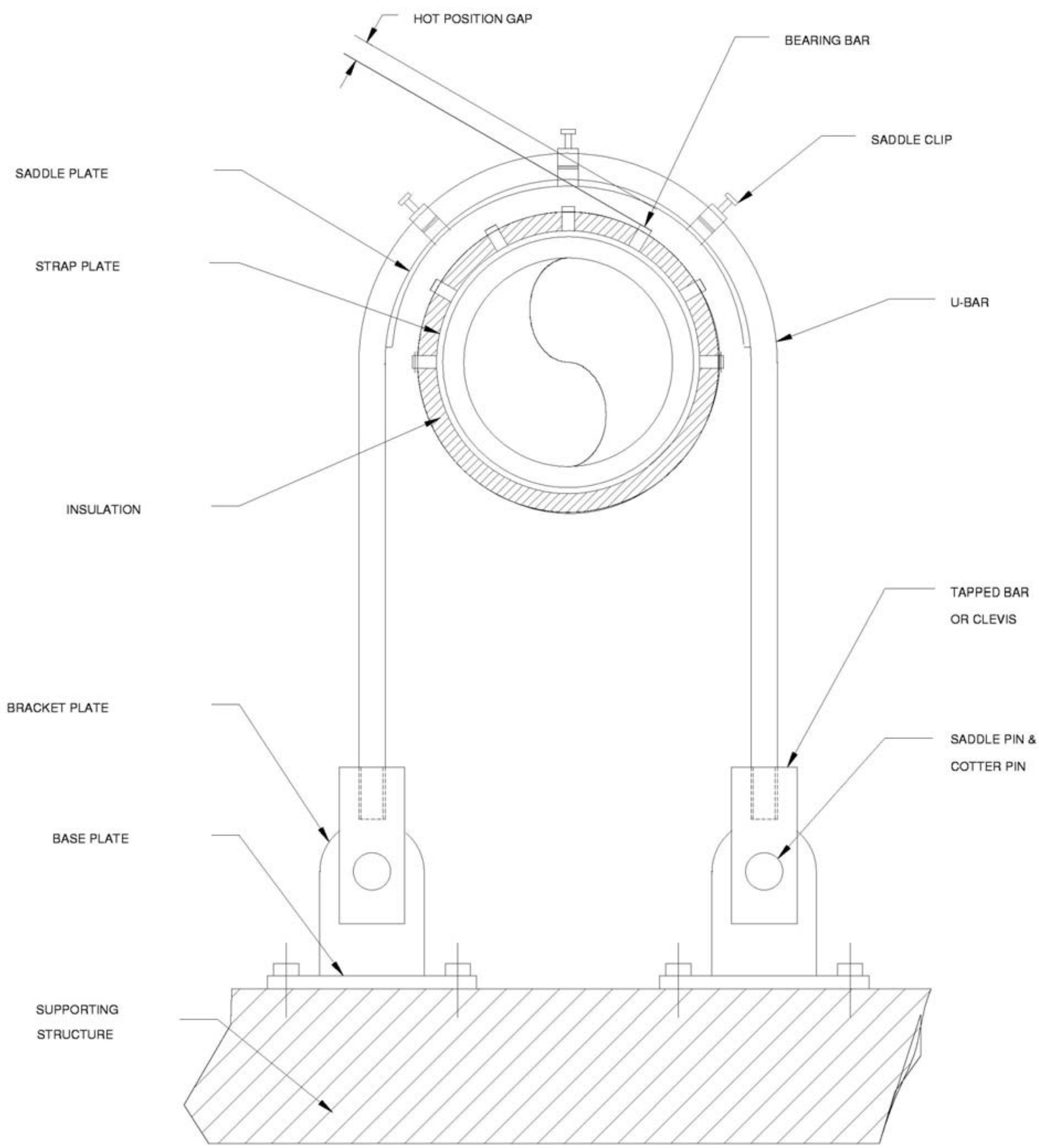


Figure 3.6-1

Typical U-Bar Restraint

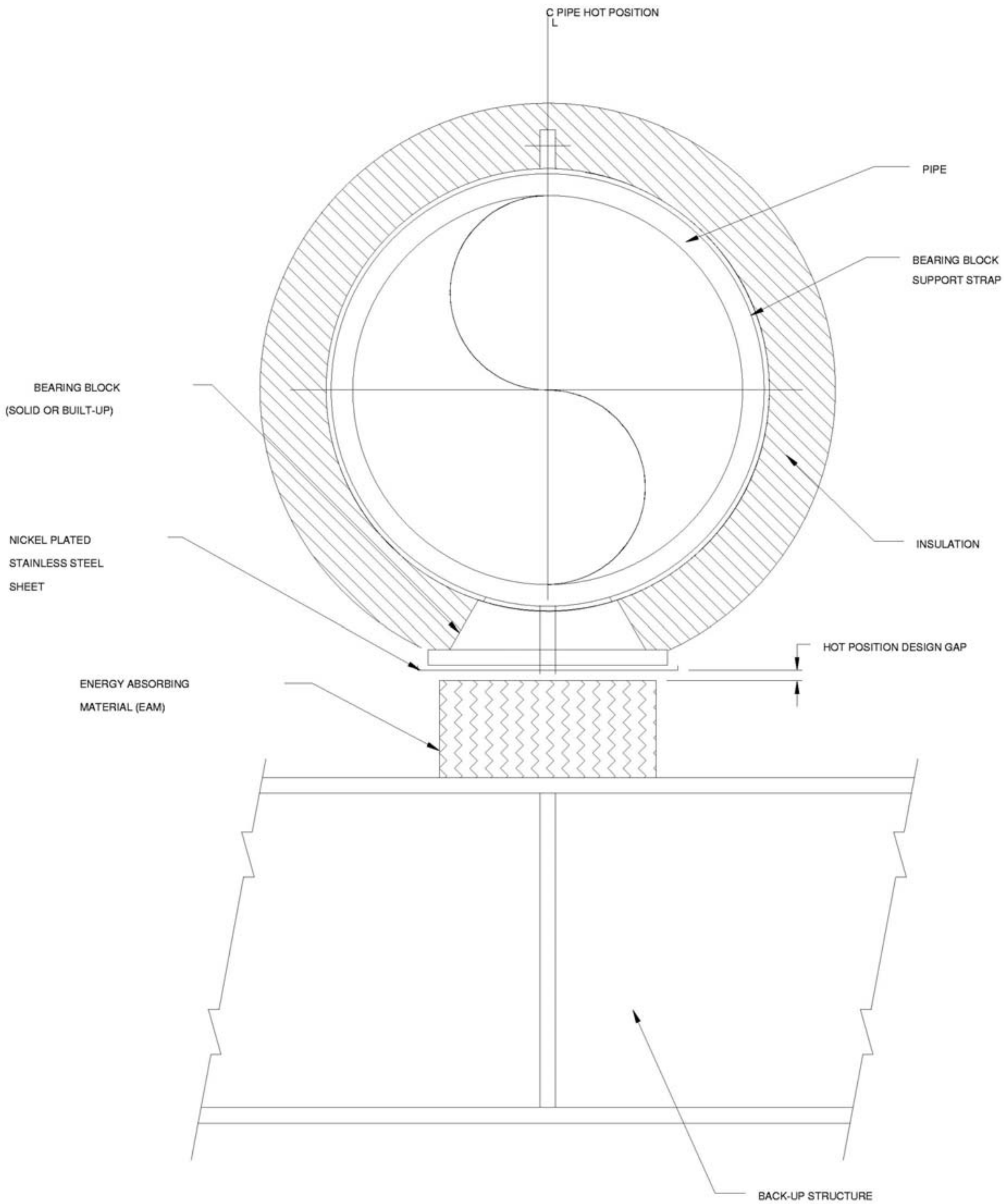


Figure 3.6-2

Typical Energy Absorbing Material Restraint

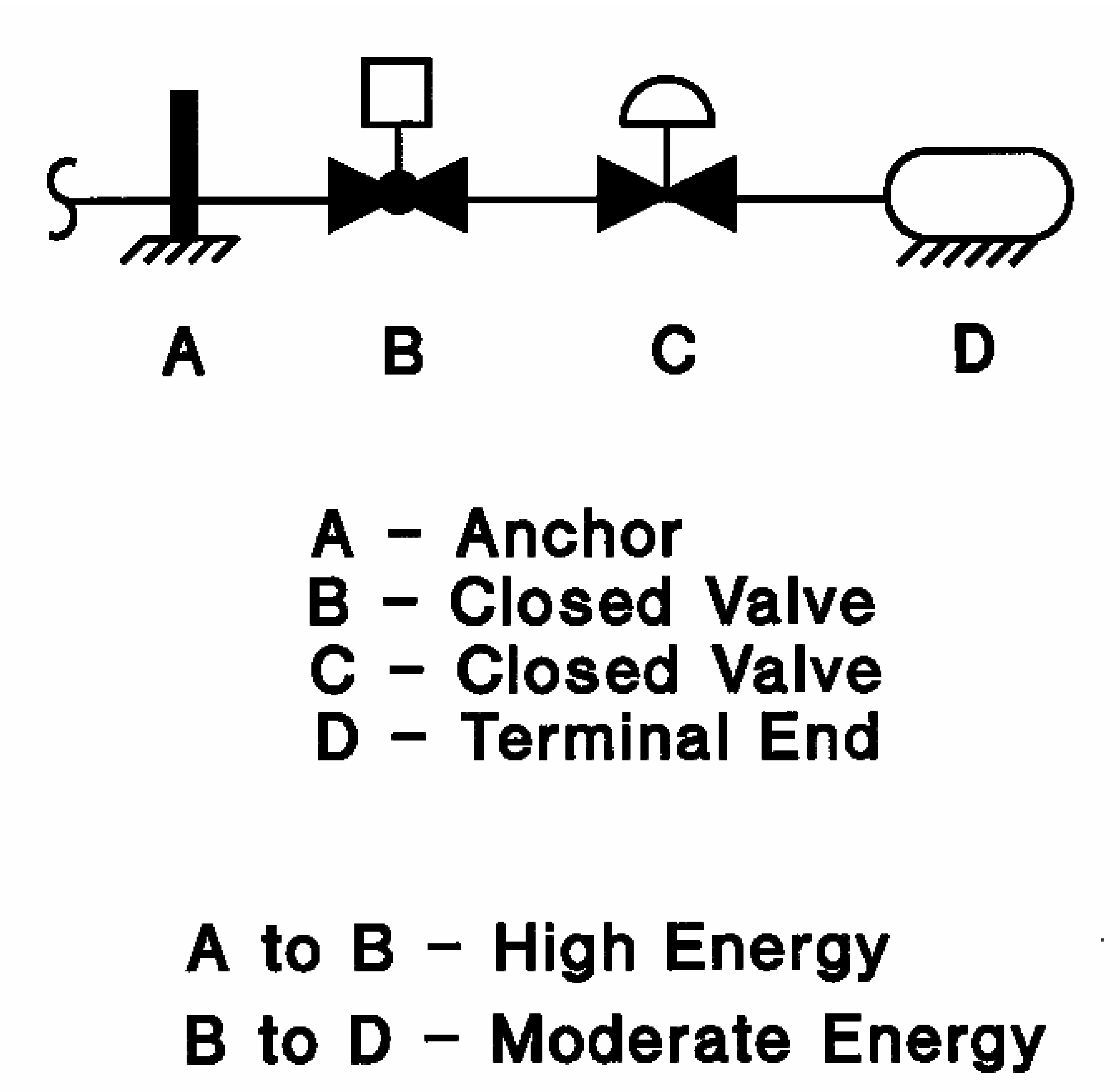


Figure 3.6-3

Terminal Ends Definitions

3.7 Seismic Design

Plant structures, systems, and components important to safety are required by General Design Criterion (GDC) 2 of Appendix A of 10 CFR 50 to be designed to withstand the effects of earthquakes without loss of capability to perform their safety functions.

Each plant structure, system, equipment, and component is classified in an applicable seismic category depending on its function. A three-level seismic classification system is used for the AP1000: seismic Category I, seismic Category II, and nonseismic. The definitions of the seismic classifications and a seismic classifications listing of structures, systems, equipment, and components are presented in Section 3.2.

Seismic design of the AP1000 seismic Categories I and II structures, systems, equipment, and components is based on the safe shutdown earthquake (SSE). The safe shutdown earthquake is defined as the maximum potential vibratory ground motion at the generic plant site as identified in Section 2.5.

The operating basis earthquake (OBE) has been eliminated as a design requirement for the AP1000. Low-level seismic effects are included in the design of certain equipment potentially sensitive to a number of such events based on a percentage of the responses calculated for the safe shutdown earthquake. Criteria for evaluating the need to shut down the plant following an earthquake are established using the cumulative absolute velocity approach according to EPRI Report NP-5930 (Reference 1) and EPRI Report TR-100082 (Reference 17). For the purposes of the shutdown criteria in Reference 1 the operating basis earthquake for shutdown is considered to be one-third of the safe shutdown earthquake.

Seismic Category I structures, systems, and components are designed to withstand the effects of the safe shutdown earthquake event and to maintain the specified design functions. Seismic Category II and nonseismic structures are designed or physically arranged (or both) so that the safe shutdown earthquake could not cause unacceptable structural interaction with or failure of seismic Category I structures, systems, and components.

3.7.1 Seismic Input

The geologic and seismologic considerations of the plant site are discussed in Section 2.5.

The peak ground acceleration of the safe shutdown earthquake has been established as 0.30g for the AP1000 design. The vertical peak ground acceleration is conservatively assumed to equal the horizontal value of 0.30g as discussed in Section 2.5.

3.7.1.1 Design Response Spectra

The AP1000 design response spectra of the safe shutdown earthquake are provided in Figures 3.7.1-1 and 3.7.1-2 for the horizontal and the vertical components, respectively.

The horizontal design response spectra for the AP1000 plant are developed, using the Regulatory Guide 1.60 spectra as the base and several evaluations to investigate the high frequency amplification effects. These evaluations included:

- Comparison of Regulatory Guide 1.60 spectra with the spectra predicted by recent eastern U.S. spectral velocity attenuation relations (References 23, 24, 25, and 26) using a suite of magnitudes and distances giving a 0.3 g peak acceleration

- Comparison of Regulatory Guide 1.60 spectra with the 10^{-4} annual probability uniform hazard spectra developed for eastern U.S. nuclear power plants by both Lawrence Livermore National Laboratory (Reference 27) and Electric Power Research Institute (Reference 28)

- Comparison of Regulatory Guide 1.60 spectra with the spectra of 79 additional old and newer components of strong earthquake time histories not considered in the original derivation of Regulatory Guide 1.60

Based on the above described evaluations, it is concluded that the eastern U.S. seismic data exceed Regulatory Guide 1.60 spectra by a modest amount in the 15 to 33 hertz frequency range when derived either from published attenuation relations or from the 10^{-4} annual probability of exceedance uniform hazard spectra at eastern U.S. sites. This conclusion is consistent with findings of other investigators that eastern North American earthquakes have more energy at high frequencies than western earthquakes. Exceedance of Regulatory Guide 1.60 spectra at the high frequency range, therefore, would be expected since Regulatory Guide 1.60 spectra are based primarily on western U.S. earthquakes. The evaluation shows that, at 25 hertz (approximately in the middle of the range of high frequencies being considered, and a frequency for which spectral amplitudes are explicitly evaluated) the mean-plus-one-standard-deviation spectral amplitudes for 5 percent damping range from about 2.1 to 4 cm/sec and average 2.7 cm/sec. Whereas, the Regulatory Guide 1.60 spectral amplitude at the same frequency and damping value equal just over 2 cm/sec.

It is concluded, therefore, that an appropriate augmented 5 percent damping horizontal design velocity response spectrum for the AP1000 project is one with spectral amplitudes equal to the Regulatory Guide 1.60 spectrum at control frequencies 0.25, 2.5, 9 and 33 hertz augmented by an additional control frequency at 25 hertz with an amplitude equal to 3 cm/sec. This spectral amplitude equals 1.3 times the Regulatory Guide 1.60 amplitude at the same frequency. The additional control point's spectral amplitude of other damping values were determined by increasing the Regulatory Guide 1.60 spectral amplitude by 30 percent.

The AP1000 design vertical response spectrum is, similarly, based on the Regulatory Guide 1.60 vertical spectra at lower frequencies but is augmented at the higher frequencies equal to the horizontal response spectrum.

The AP1000 design response spectra's relative values of spectrum amplification factors for control points are presented in Table 3.7.1-3.

The design response spectra are applied at the foundation level in the free field.

3.7.1.2 Design Time History

A "single" set of three mutually orthogonal, statistically independent, synthetic acceleration time histories is used as the input in the dynamic analysis of seismic Category I structures. The synthetic time histories were generated by modifying a set of actual recorded "TAFT" earthquake time histories. The design time histories include a total time duration equal to 20 seconds and a corresponding stationary phase, strong motion duration greater than 6 seconds. The acceleration, velocity, and displacement time-history plots for the three orthogonal earthquake components, "H1," "H2," and "V," are presented in Figures 3.7.1-3, 3.7.1-4, and 3.7.1-5. Design horizontal time history, H1, is applied in the north-south (Global X or 1) direction; design horizontal time history, H2, is applied in the east-west (global Y or 2) direction; and design vertical time history is applied in the vertical (global Z or 3) direction. The cross-correlation coefficients between the three components of the design time histories are as follows:

$$\rho_{12} = 0.05,\ \rho_{23} = 0.043, \text{ and } \rho_{31} = 0.140$$

where 1, 2, 3 are the three global directions.

Since the three coefficients are less than 0.16 as recommended in Reference 30, which was referenced by NRC Regulatory Guide 1.92, Revision 1, it is concluded that these three components are statistically independent. The design time histories are applied at the foundation level in the free field.

The ground motion time histories (H1, H2, and V) are generated with time step size of 0.010 second for applications in soil structure interaction analyses. For applications in the fixed-base mode superposition time-history analyses, the time step size is reduced to 0.005 second by linear interpolation. The maximum frequency of interest in the horizontal and vertical seismic analysis of the nuclear island for the hard rock site is 33 hertz. Modes with higher frequencies are included in the analysis so that the mass in these higher modes is included in the member forces. The maximum "cut-off" frequency for the fixed-base analyses is well within the Nyquist frequency limit.

The comparison plots of the acceleration response spectra of the time histories versus the design response spectra for 2, 3, 4, 5, and 7 percent critical damping are shown in Figures 3.7.1-6, 3.7.1-7, and 3.7.1-8. The SRP 3.7.1, Table 3.7.1-1, provision of frequency intervals is used in the computation of these response spectra.

In SRP 3.7.1 the NRC introduced the requirement of minimum power spectral density to prevent the design ground acceleration time histories from having a deficiency of power over any frequency range. SRP 3.7.1, Revision 2, specifies that the use of a single time history is justified by satisfying a target power spectral density (PSD) requirement in addition to the design response spectra enveloping requirements. Furthermore, it specifies that when spectra other than Regulatory Guide 1.60 spectra are used, a compatible power spectral density shall be developed using procedures outlined in NUREG/CR-5347 (Reference 29).

The NUREG/CR-5347 procedures involve ad hoc hybridization of two earlier power spectral density envelopes. Since the modification to the RG 1.60 design spectra adopted for AP1000 (see subsection 3.7.1.1) is relatively small (compared to the uncertainty in the fit to RG 1.60 of power

spectral density-compatible time histories referenced in NUREG/CR-5347) and occurs only in the frequency range between 9 to 33 hertz, a project-specific power spectral density is developed using a slightly different hybridization for the higher frequencies.

Since the original RG 1.60 spectrum and the project-specific modified RG 1.60 spectrum are identical for frequencies less than 9 hertz, no modification to the power spectral density is done in this frequency range. At frequencies above 9 hertz, the third and the fourth legs of the power spectral density are slightly modified as follows:

- The frequency at which the design response spectrum inflected towards a 1.0 amplification factor at 33 hertz takes place at 25 hertz in the AP1000 spectrum rather than at 9 hertz as in the RG 1.60 spectrum. The third leg of the power spectral density, therefore, is extended to about 25 hertz rather than 16 hertz.

- The lead coefficient to the fourth leg of the power spectral density is changed to connect with the extended third leg.

The AP1000 augmented power spectral density, anchored to 0.3 g, is as follows:

$S_0(f) = 58.5\ (f/2.5)^{0.2}\ in^2/sec^3,\ f \leq 2.5$ hertz
$S_0(f) = 58.5\ (2.5/f)^{1.8}\ in^2/sec^3,\ 2.5$ hertz $\leq f \leq 9$ hertz
$S_0(f) = 5.832\ (9/f)^3\ in^2/sec^3,\ 9$ hertz $\leq f \leq 25$ hertz
$S_0(f) = 0.27\ (25/f)^8\ in^2/sec^3,\ 25$ hertz $\leq f$

The AP1000 Minimum Power Spectral Density is presented in Figure 3.7.1-9. This AP1000 target power spectral density is compatible with the AP1000 horizontal design response spectra and envelops a target power spectral density compatible with the AP1000 vertical design response spectra. This AP1000 target power spectral density, therefore, is conservatively applied to the vertical response spectra.

The comparison plots of the power spectral density curve of the AP1000 acceleration time histories versus the target power spectral density curve are presented in Figures 3.7.1-10, 3.7.1-11, and 3.7.1-12. The power spectral density functions of the design time histories are calculated at uniform frequency steps of 0.0489 hertz. The power spectral densities presented in Figures 3.7.1-10 through 3.7.1-12 are the averaged power spectral density obtained over a moving frequency band of ±20 percent centered at each frequency. The power spectral density amplitude at frequency (f) has the averaged power spectral density amplitude between the frequency range of 0.8 f and 1.2 f as stated in appendix A of Revision 2 of SRP 3.7.1.

3.7.1.3 Critical Damping Values

Energy dissipation within a structural system is represented by equivalent viscous dampers in the mathematical model. The damping coefficients used are based on the material, load conditions, and type of construction used in the structural system. The safe shutdown earthquake damping values used in the dynamic analysis are presented in Table 3.7.1-1. The damping values are based on Regulatory Guide 1.61, ASCE Standard 4-98 (Reference 3), except for the

damping value of the primary coolant loop piping, which is based on Reference 22, and conduits, cable trays and their related supports.

The damping values for conduits, cable trays and their related supports are shown in Table 3.7.1-1 and Figure 3.7.1-13. The damping value of conduit, empty cable trays, and their related supports is similar to that of a bolted structure, namely 7 percent of critical. The damping value of filled cable trays and supports increases with increased cable fill and level of seismic excitation. For cable trays and supports demonstrated to be similar to those tested, damping values of Figure 3.7.1-13 may be used. These are based on test results (Reference 19).

For structures or components composed of different material types, the composite modal damping is calculated using the stiffness-weighted method based on Reference 3. The modal damping values equal:

$$\beta_n = \sum_{i=1}^{nc} \frac{\{\phi_n\}^T \beta_i \left[K_t\right]_i \{\phi_n\}}{\{\phi_n\}^T \left[K_t\right] \{\phi_n\}}$$

where:

β_n	=	ratio of critical damping for mode n
nc	=	number of elements
$\{\phi_n\}$	=	mode n (eigenvector)
$\left[K_t\right]_i$	=	stiffness matrix of element i
β_i	=	ratio of critical damping associated with element i
$\left[K_t\right]$	=	total system stiffness matrix

3.7.1.4 Supporting Media for Seismic Category I Structures

The supporting media will be described by the Combined License applicant consistent with the information items in subsection 2.5.4. Seismic analyses for a rock site are described in subsection 3.7.2.

The AP1000 nuclear island consists of three seismic Category I structures founded on a common basemat. The three structures that make up the nuclear island are the coupled auxiliary and shield buildings, the steel containment vessel, and the containment internal structures. [*The nuclear island is shown in Figure 3.7.1-14.*]* The foundation embedment depth, foundation size, and total height of the seismic Category I structures are presented in Table 3.7.1-2.

3.7.2 Seismic System Analysis

Seismic Category I structures, systems, and components are classified according to Regulatory Guide 1.29. Seismic Category I building structures of AP1000 consist of the containment building (the steel containment vessel and the containment internal structures), the shield building, and the auxiliary building. These structures are founded on a common basemat and are collectively known as the nuclear island or nuclear island structures. [*Key dimensions, such as thickness of the*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

basemat, floor slabs, roofs and walls, of the seismic Category I building structures are shown in Figure 3.7.2-12.]*

Seismic systems are defined, according to SRP 3.7.2, Section II.3.a, as the seismic Category I structures that are considered in conjunction with their foundation and supporting media to form a soil-structure interaction model. The following subsections describe the seismic analyses performed for the nuclear island. Other seismic Category I structures, systems, equipment, and components not designated as seismic systems (that is, heating, ventilation, and air-conditioning systems; electrical cable trays; piping systems) are designated as seismic subsystems. The analysis of seismic subsystems is presented in subsection 3.7.3.

Seismic Category I building structures are on the nuclear island. Other building structures are classified nonseismic or seismic Category II. Nonseismic structures are analyzed and designed for seismic loads according to the Uniform Building Code (Reference 2) requirements for Zone 2A. Seismic Category II building structures are designed for the safe shutdown earthquake using the same methods and design allowables as are used for seismic Category I structures. The acceptance criteria are based on ACI 349 for concrete structures and on AISC N690 for steel structures including the supplemental requirements described in subsections 3.8.4.4.1 and 3.8.4.5. The seismic Category II building structures are constructed to the same requirements as the nonseismic building structures, ACI 318 for concrete structures and AISC-S355 for steel structures.

Fixed base seismic analyses are performed for the nuclear island at a rock site. The analyses generate a set of in-structure responses (design member forces, nodal accelerations, nodal displacements, and floor response spectra) which are used in the design and analysis of seismic Category I structures, components, and seismic subsystems.

Table 3.7.2-14 and Figure 3.7.2-13 summarize the types of models and analysis methods that are used in the seismic analyses of the nuclear island, as well as the type of results that are obtained and where they are used in the design. The dynamic analyses of the nuclear island building structures are performed using the following ANSYS models:

1. The finite element shell dynamic model of the coupled auxiliary and shield building is a finite element model using primarily shell elements. The portion of the model up to the elevation of the auxiliary building roof is developed using the solid model features of ANSYS, which allow definition of the geometry and structural properties. The nominal element size in the auxiliary building model is about 9 feet so that each wall has two elements for the wall height of about 18 feet between floors. This mesh size, which is the same as that of the solid model, has sufficient refinement for global seismic behavior. It is combined with a finite element model of the shield building roof and cylinder above the elevation of the auxiliary building roof. This model is used to develop modal properties (frequencies and mode shapes). Static analyses are also performed on portions of this model to define properties for the stick model. This model is shown in Figure 3.7.2-1.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

2. The finite element shell model of the containment internal structures is a finite element model using primarily shell elements. It is developed using the solid model features of ANSYS, which allow definition of the geometry and structural properties. This model is used in both static and dynamic analyses. It models the concrete structures inside the shield building including the basemat. This model is used to develop modal properties (frequencies and mode shapes). Analyses are performed on portions of this model to define properties for the stick model. Static analyses are also performed on the model to obtain member forces in the walls. The walls and basemat inside containment for this model is shown in Figure 3.7.2-2. This model is also used as a superelement in both the finite element shell dynamic model of the nuclear island and in the 3D finite element basemat model (see subsection 3.8.5.4-1).

3. The finite element model of the containment vessel is an axisymmetric model fixed at elevation 100′. This model is used in both static and dynamic analyses. The model is used to develop modal properties (frequencies and mode shapes). Analyses are performed on portions of this model to define properties for the stick model. Static analyses are also performed on the model to obtain shell stresses. This model is shown in Figure 3.8.2-6.

4. The nuclear island lumped mass stick model consists of the stick models of the individual buildings interconnected by rigid links. Each individual stick model is developed to match the modal properties of the finite element models described in 1, 2, and 3 above. Modal analyses and seismic time history analyses are performed using this model. Plant design response spectra are developed from these analyses along with equivalent static seismic accelerations for analysis of the building structures. The individual stick models are shown in Figures 3.7.2-4, 3.7.2-5, and 3.7.2-6. The reactor coolant loop model is shown in Figure 3.7.2-7. The polar crane model is shown in Figure 3.7.2-8. The interconnection between the sticks is shown in Figure 3.7.2-18.

5. The finite element shell dynamic model of the nuclear island is also used in seismic time history analyses. This model uses the coupled auxiliary and shield building described in 1 above. It also includes the finite element model of the basemat inside the shield building and a superelement of the containment internal structures generated from the finite element model described in 2 above. Results from time history analyses from this model are compared to the results from the nuclear island lumped mass stick model. The results are used for development of vertical response spectra and for the equivalent static seismic acceleration of flexible floors and walls and the shield building roof.

The models of the containment internal structures and containment vessel described in 2 and 3 above are also used in equivalent static analyses to provide design member forces in each structure. A separate GTSTRUDL model as shown in Figure 3.8.4-3 is used for static analyses of the shield building roof. Member forces in the auxiliary and shield building are obtained from static analyses of the following model:

6. The equivalent static ANSYS finite element model of the auxiliary and shield building is more refined than the finite element model described in 1 above. This model is developed by meshing one area of the solid model with four finite elements. The nominal element size in this auxiliary building model is about 4.5 feet so that each wall has four elements for the wall

height of about 18 feet between floors. This refinement is used to calculate the design member forces and moments for the equivalent static accelerations obtained from the time history analyses of the nuclear island stick model. The stick model of the containment internal structures, which includes the basemat within the shield building, is also included.

The seismic analyses of the nuclear island are summarized in a seismic analysis summary report. This report describes the development of the finite element models, the fixed base analyses, and the results thereof. A separate report provides the floor response spectra for the nuclear island.

3.7.2.1 Seismic Analysis Methods

Seismic analyses of the nuclear island are performed in conformance with the criteria within SRP 3.7.2.

Seismic analyses, using the equivalent static acceleration method, and the mode superposition time-history method, are performed for the safe shutdown earthquake to determine the seismic force distribution for use in the design of the nuclear island structures, and to develop in-structure seismic responses (accelerations, displacements, and floor response spectra) for use in the analysis and design of seismic subsystems.

3.7.2.1.1 Equivalent Static Acceleration Analysis

Equivalent static analyses, using computer program ANSYS (Reference 36), are performed to obtain the seismic forces and moments required for the structural design of the auxiliary building, the shield building, the steel containment vessel (see subsection 3.8.2.4.1.1), and the containment internal structures on the nuclear island. Equivalent static loads are applied to the finite element models using the maximum acceleration results from the time history analyses of the stick models described in subsection 3.7.2.1.2. Accidental torsional moments are applied as described in subsection 3.7.2-11.

Coupled Shield and Auxiliary Buildings on Fixed Base

The analyses are performed using the three-dimensional, finite element model of the coupled shield and auxiliary buildings including the shield building roof. The effect of the containment internal structures are considered by inclusion of the stick models developed and discussed in subsection 3.7.2.3, or by use of substructures. Figure 3.7.2-1 shows the finite element model of the coupled shield and auxiliary buildings. In addition, a section of the coupled shield and auxiliary buildings is presented in Figure 3.7.2-3.

Equivalent static analyses are performed for the hard rock site where the soil-structure interaction effect is negligible. The analyses are performed using the fixed-base, three-dimensional, finite element models fixed at elevation 63′-6″. The support provided by the embedment below grade is not considered in these analyses.

Containment Internal Structures

Equivalent static analyses of the containment internal structures on a fixed base are performed using the three-dimensional, finite element model of the containment internal structures developed

and discussed in subsection 3.7.2.3. Figure 3.7.2-2 shows the finite element model of the containment internal structures.

3.7.2.1.2 Time-History Analysis

Mode superposition time-history analyses using computer program ANSYS are performed to obtain the in-structure seismic response needed in the analysis and design of seismic subsystems.

The three-dimensional, lumped-mass stick models of the nuclear island structures developed as described in subsection 3.7.2.3 are used to obtain the in-structure responses. The lumped-mass stick models of the nuclear island structures are presented in Figure 3.7.2-4 for the coupled shield and auxiliary buildings, in Figure 3.7.2-5 for the steel containment vessel, in Figure 3.7.2-6 for the containment internal structures, and in Figure 3.7.2-7 for the reactor coolant loop model. The individual building lumped-mass stick models are interconnected with rigid links to form the overall dynamic model of the nuclear island.

The three-dimensional finite element model of the auxiliary and shield building, or a portion thereof, developed as described in subsections 3.7.2.3 and 3.7.2.3.1 is used to obtain the in-structure vertical response spectra of the auxiliary building including flexible floors. This model is used for the vertical analysis of the auxiliary building since the stick model is developed to match the fundamental vertical frequency of the shield building and does not represent the fundamental vertical frequencies of the auxiliary building, which is significantly lower than the shield building.

For the hard rock site, the soil-structure interaction effect is negligible. Therefore, for the hard rock site, the nuclear island is analyzed as a fixed-base structure, using computer program ANSYS without the foundation media. The three components of earthquake (two horizontal and one vertical time histories) are applied simultaneously in the analysis. The base of the stick model is fixed at the bottom of the basemat at elevation 60′-6″. The basemat is 6 feet thick. Since the finite element model of the auxiliary and shield building uses shell elements to represent the 6-foot-thick basemat, the nodes of the basemat element are at the center of the basemat (elevation 63′-6″). The finite element model of the containment internal structures uses solid elements, which extend down to elevation 60′-6″. When the finite element models are combined and used in the time history analyses, the auxiliary building finite element model is fixed at the shell element basemat nodes (elevation 63′-6″) and the base of the containment internal structures is fixed at the bottom of the solid element base nodes (elevation 60′-6″). This difference in elevation of the base fixity is not significant since the concrete between elevations 60′-6″ and 63′-6″, below the auxiliary building, is nearly rigid. There is no lateral support due to soil or hard rock below grade. This case results in higher response than a case analyzed with full lateral support below grade.

3.7.2.1.3 Response Spectrum Analysis

Equivalent static acceleration and mode superposition time-history methods are primarily used for the evaluation of the nuclear island structures. Response spectrum analyses may be used to perform an analysis of a particular structure or portion of structure using the procedures described in subsections 3.7.2.6, 3.7.2.7, and 3.7.3.

3.7.2.2 Natural Frequencies and Response Loads

Modal analyses are performed for the lumped-mass stick models of the seismic Category I structures on the nuclear island developed in subsection 3.7.2.3. Table 3.7.2-1 and Figure 3.7.2-9 summarize the modal properties of the stick model representing the coupled shield and auxiliary buildings. Table 3.7.2-2 and Figure 3.7.2-10 show the modal properties of the steel containment vessel. Table 3.7.2-3 (sheet 1) and Figure 3.7.2-11 show the modal properties for the containment internal structures without the reactor coolant loop stick model. Table 3.7.2-3 (sheet 2) shows the modal properties for the reactor coolant loop stick model. Table 3.7.2-4 shows the modal properties of the overall stick model of the nuclear island.

The time history seismic analysis of the nuclear island considers 200 vibration modes, extending up to a frequency of 83.8 hertz as shown in Table 3.7.2-4. The total cumulative mass participating in the seismic response constitute more than 80 percent of the total mass of the nuclear island.

Maximum absolute acceleration (ZPA) responses at selected locations on the coupled shield and auxiliary buildings, the steel containment vessel, and the containment internal structures are summarized in Tables 3.7.2-5, 3.7.2-6, and 3.7.2-7, respectively. Similarly, maximum displacement responses relative to the base of the lumped-mass nuclear island stick model at the underside of basemat are summarized in Tables 3.7.2-8 through 3.7.2-10, respectively, for the coupled shield and auxiliary buildings, the steel containment vessel, and the containment internal structures.

Maximum seismic response forces and moments determined in the lumped-mass stick model are summarized in Tables 3.7.2-11 through 3.7.2-13, respectively, for the coupled shield and auxiliary buildings, the steel containment vessel, and the containment internal structures.

3.7.2.3 Procedure Used for Modeling

Based on the general plant arrangement, three-dimensional, finite element models are developed for the nuclear island structures: a finite element model of the coupled shield and auxiliary buildings, a finite element model of the containment internal structures, a finite element model of the shield building roof, and an axisymmetric shell model of the steel containment vessel. These three-dimensional, finite element models provide the basis for the development of the lumped-mass stick model of the nuclear island structures.

The finite element models of the coupled shield and auxiliary buildings, and the containment internal structures are based on the gross concrete section with the modulus based on the specified compressive strength of concrete. When the finite element or stick models of these buildings are used in time history or response spectrum dynamic analyses, the stiffness properties are reduced by a factor of 0.8 to consider the effect of cracking as recommended in Table 6-5 of FEMA 356 (Reference 5).

Three-dimensional, lumped-mass stick models are developed to represent the steel containment vessel, the containment internal structures, and the coupled shield and auxiliary buildings. Discrete mass points are provided at major floor elevations and at locations of structural discontinuities. The structural eccentricities between centers of rigidity and the centers of mass of the structures are considered. These seismic models consist of lumped masses connected to

vertical elastic structural elements by horizontal stiff beam elements to simulate eccentricity. The individual building lumped-mass stick models are interconnected with other stiff beam elements to form the overall dynamic model of the nuclear island.

Seismic subsystems coupled to the overall dynamic model of the nuclear island include the coupling of the reactor coolant loop model to the model of the containment internal structures, and the coupling of the polar crane model to the model of the steel containment vessel. The criteria used for decoupling seismic subsystems from the nuclear island model is according to Section II.3.b of SRP 3.7.2, Revision 2. The total mass of other major subsystems and equipment is less than one percent of the respective supporting nuclear island structures; therefore, the mass of other major subsystems and equipment is included as concentrated lumped-mass only.

3.7.2.3.1 Coupled Shield and Auxiliary Buildings and Containment Internal Structures

The finite element models of the coupled shield and auxiliary buildings and the reinforced concrete portions of the containment internal structures are based on the gross concrete section with the modulus based on the specified compressive strength of concrete of contributing structural walls and slabs. The properties of the concrete-filled structural modules are computed using the combined gross concrete section and the transformed steel face plates of the structural modules. Furthermore, the weight density of concrete plus the uniformly distributed miscellaneous dead weights are considered by adding surface mass or by adjusting the material mass density of the structural elements. An equivalent tributary slab area load of 50 pounds per square foot is considered to represent miscellaneous deadweight such as minor equipment, piping and raceways. 25 percent of the floor live load or 75 percent of the roof snow load, whichever is applicable, is considered as mass in the global seismic models. Major equipment weights are distributed over the floor area or are included as concentrated lumped masses at the equipment locations. Figures 3.7.2-1 and 3.7.2-2 show, respectively, the finite element models of the coupled shield and auxiliary buildings and the containment internal structures. The auxiliary and shield building is modeled with shell elements and the base of the finite element model is at the middle of the basemat at elevation 63′-6″. The bottom of the containment and internal structures are modeled with solid elements and the base of the finite element model is at the underside of the basemat at elevation 60′-6″. The interface between the models is at a radius of 69′-6″ at the inside face of the shield building.

Because of the irregular structural configuration, the properties of the three-dimensional, lumped-mass stick models are determined using building sections extracted from the three-dimensional building finite element models. Figure 3.7.2-3 shows a typical building section from the coupled shield and auxiliary buildings finite element model. The properties of the stick model beam elements, including the location of centroid, center of rigidity and center of mass, and equivalent sectional areas and moment of inertia, are computed using specific finite element sections representing the walls and columns between floor elevations of the structures. The equivalent translation and rotational stiffness (sectional areas and moment of inertia) of the three-dimensional beams are computed by applying unit forces and moments at the top of the specific finite element sections.

The eccentricities between the centroids (the neutral axis for axial and bending deformation), the centers of rigidity (the neutral axis for shear and torsional deformation), and the centers of mass of the structures are represented by a combination of two sticks in the seismic model. One stick

represents only the axial areas of the structural member and is located at the centroid. This stick model is developed to resist the vertical seismic input motion. The other stick represents other beam element properties except the axial area of the structural member and is located at the center of rigidity. This stick model is developed to resist the horizontal seismic input motions. At a typical model elevation, there are four horizontal stiff beam elements connecting the center of mass node to the sticks located at the shear centers and the centroids of the wall sections above and below.

The shield building roof including the passive containment cooling system water storage tank is represented by a lumped-mass stick model simulating the dynamic behavior of this portion of the roof structure. The member properties of the stick model are selected to match the frequencies and mode shapes from the finite element model. The portion of the roof from the bottom of the air inlets to the bottom of the passive containment cooling system tank is modelled by an equivalent beam. This lumped-mass stick model is combined with the lumped-mass stick model representing the lower portion of the shield building.

The in-containment refueling water storage tank (IRWST) is included in the three-dimensional finite element models used in the development of the lumped-mass stick model representing the containment internal structures (CIS). Therefore, the lumped-mass stick model of the containment internal structures includes the stiffness and mass effect of the in-containment refueling water storage tank.

Figures 3.7.2-4 and 3.7.2-6 show, respectively, the lumped-mass stick models of the coupled shield and auxiliary buildings and the containment internal structures.

A simplified reactor coolant loop model is developed and coupled with the containment internal structures model for the seismic analysis. The reactor coolant loop stick model is presented in Figure 3.7.2-7.

3.7.2.3.2 Steel Containment Vessel

The steel containment vessel is a freestanding, cylindrical, steel shell structure with ellipsoidal upper and lower steel domes. The three-dimensional, lumped-mass stick model of the steel containment vessel is developed based on the axisymmetric shell model. Figure 3.7.2-5 presents the steel containment vessel stick model. In the stick model, the properties are calculated as follows:

- Members representing the cylindrical portion are based on the properties of the actual circular cross section of the containment vessel.

- Members representing the bottom head are based on equivalent stiffnesses calculated from the shell of revolution analyses for static 1.0g in vertical and horizontal directions.

- Shear, bending and torsional properties for members representing the top head are based on the average of the properties at the successive nodes, using the actual circular cross section. These are the properties that affect the horizontal modes. Axial properties, which affect the vertical modes, are based on equivalent stiffnesses calculated from the shell of revolution analyses for static 1.0g in the vertical direction.

This method used to construct a stick model from the axisymmetric shell model of the containment vessel is verified by comparison of the natural frequencies determined from the stick model and the shell of revolution model as shown in Table 3.7.2-15. The shell of revolution vertical model (n = 0 harmonic) has a series of local shell modes of the top head above elevation 265′ between 23 and 30 hertz. These modes are predominantly in a direction normal to the shell surface and cannot be represented by a stick model. These local modes have small contribution to the total response to a vertical earthquake as they are at a high frequency where seismic excitation is small. The only seismic Category I components attached to this portion of the top head are the water distribution weirs of the passive containment cooling system. These weirs are designed such that their fundamental frequencies are outside the 23 to 30 hertz range of the local shell modes.

The containment air baffle, presented in subsection 3.8.4.1.3, is supported from the steel containment vessel at regular intervals so that a gap is maintained for airflow. It is constructed with individual panels which do not contribute to the stiffness of the containment vessel. The fundamental frequency of the baffle panels and supports is about twice the fundamental frequency of the containment vessel. The mass of the air baffle is small, equal to approximately 10 percent of the vessel plates to which it is attached. The air baffle, therefore, is assumed to have negligible interaction with the steel containment vessel. Only the mass of the air baffle is considered and added at the appropriate elevations of the steel containment vessel stick model.

The polar crane is supported on a ring girder which is an integral part of the steel containment vessel at elevation 228′-0″ as shown in Figure 3.8.2-1. It is modeled as a multi-degree of freedom system attached to the steel containment shell at elevation 224′ (midpoint of ring girder) as shown in Figure 3.7.2-5. The polar crane is modeled as shown in Figure 3.7.2-8 with five masses at the mid-height of the bridge at elevation 233′-6″ and one mass for the trolley. The polar crane model includes the flexibility of the crane bridge girders and truck assembly, and the containment shell's local flexibility. When fixed at the center of containment, the model shows fundamental frequencies of 3.7 hertz transverse to the bridge, 6.4 hertz vertically, and 8.5 hertz along the bridge.

[*During plant operating conditions, the polar crane is parked in the plant north-south direction with the trolley located at one end near the containment shell.*]* In the seismic model, the crane bridge spans in the north-south direction and the mass eccentricity of the trolley is considered by locating the mass of the trolley at the northern limit of travel of the main hook. Furthermore, the mass eccentricity of the two equipment hatches and the two personnel airlocks are considered by placing their mass at their respective center of mass as shown in Figure 3.7.2-5.

3.7.2.3.3 Nuclear Island Seismic Model

The various building lumped-mass stick models are interconnected with rigid links to form the overall dynamic model of the nuclear island as shown in Figure 3.7.2-18. For the fixed-base analysis, the nuclear island seismic model consists of 93 mass points and 403 dynamic degrees of freedom. The mass properties of the lumped-mass stick models include all tributary mass expected to be present during plant operating conditions. This includes the dead weight of walls and slabs, weight of major equipment, and equivalent tributary slab area loads representing miscellaneous equipment, piping and raceways.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

The hydrodynamic mass effect of the water within the passive containment cooling system water tank on the shield building roof, the in-containment refueling water storage tank within the containment internal structures, and the spent fuel pool in the auxiliary building is evaluated. The convective (sloshing) effect of the water mass within the passive containment cooling system water tank on the shield building roof is included in the nuclear island seismic model. The total mass of the water in the in-containment refueling water storage tank within the containment internal structures, and the spent fuel pool in the auxiliary building is included in the nuclear island seismic model.

3.7.2.4 Soil-Structure Interaction

Soil-structure interaction is not significant for the nuclear island founded on rock with a shear wave velocity greater than 8000 feet per second.

3.7.2.5 Development of Floor Response Spectra

The design floor response spectra are generated according to Regulatory Guide 1.122.

Seismic floor response spectra are computed using time-history responses determined from the nuclear island seismic analyses. The time-history responses for the hard rock condition are determined from a mode superposition time history analysis using computer program ANSYS. Floor response spectra for damping values equal to 2, 3, 4, 5, 7, 10, and 20 percent of critical damping are computed at the required locations.

The floor response spectra for the design of subsystems and components are generated by broadening the nodal response spectra determined for the hard rock site.

The spectral peaks associated with the structural frequencies are broadened by ±15 percent to account for the variation in the structural frequencies, due to the uncertainties in parameters such as material and mass properties of the structure and soil, damping values, seismic analysis technique, and the seismic modeling technique. Figure 3.7.2-14 shows the broadening procedure used to generate the design floor response spectra.

Floor response spectra for the auxiliary building are obtained from the three-dimensional model as described in subsection 3.7.2.1.2. These spectra are developed for the specific location in the auxiliary building. Where spectra at a number of nodes have similar characteristics, a single set of spectra may be developed by enveloping the broadened spectra at each of the nodes.

The safe shutdown earthquake floor response spectra for 5 percent damping, at representative locations of the coupled auxiliary and shield buildings, the steel containment vessel, and the containment internal structures are presented in Figures 3.7.2-15 through 3.7.2-17.

3.7.2.6 Three Components of Earthquake Motion

Seismic system analyses are performed considering the simultaneous occurrences of the two horizontal and the vertical components of earthquake.

In mode superposition time-history analyses using computer program ANSYS, the three components of earthquake are applied either simultaneously or separately. In the ANSYS analyses with the three earthquake components applied simultaneously, the effect of the three components of earthquake motion is included within the analytical procedure so that further combination is not necessary.

In analyses with the earthquake components applied separately and in the response spectrum and equivalent static analyses, the effect of the three components of earthquake motion are combined using one of the following methods:

- For seismic analyses with the statistically independent earthquake components applied separately, the time-history responses from the three earthquake components are combined algebraically at each time step to obtain the combined response time-history.

- The peak responses due to the three earthquake components from the response spectrum and equivalent static analyses are combined using the square root of the sum of squares (SRSS) method.

- The peak responses due to the three earthquake components are combined directly, using the assumption that when the peak response from one component occurs, the responses from the other two components are 40 percent of the peak (100 percent-40 percent-40 percent method). Combinations of seismic responses from the three earthquake components, together with variations in sign (plus or minus), are considered. This method is used in the nuclear island basemat analyses, the containment vessel analyses and the shield building roof analyses.

The containment vessel is analyzed using axisymmetric finite element models. These axisymmetric building structures are analyzed for one horizontal seismic input from any horizontal direction and one vertical earthquake component. Responses are combined by either the square root of the sum of squares method or by a modified 100 percent-40 percent-40 percent method in which one component is taken at 100 percent of its maximum value and the other is taken at 40 percent of its maximum value.

For the seismic responses presented in subsection 3.7.2.2, the effect of three components of earthquake are considered as follows:

- Mode Superposition Time History Analysis (program ANSYS) – the time history responses from the three components of earthquake motion are combined algebraically at each time step.

A summary of the dynamic analyses performed and the combination techniques used are presented in Table 3.7.2-16.

3.7.2.7 Combination of Modal Responses

The modal responses of the response spectrum system structural analysis are combined using the grouping method shown in Section C of Regulatory Guide 1.92, Revision 1. When high frequency

effects are significant, they are included using the procedure given in Appendix A to SRP 3.7.2. In the fixed base mode superposition time history analysis of the hard rock site, the total seismic response is obtained by superposing the modal responses within the analytical procedure so that further combination is not necessary.

A summary of the dynamic analyses performed and the combination techniques used are presented in Table 3.7.2-16.

3.7.2.8 Interaction of Seismic Category II and Nonseismic Structures with Seismic Category I Structures, Systems or Components

Nonseismic structures are evaluated to determine that their seismic response does not preclude the safety functions of seismic Category I structures, systems or components. This is accomplished by satisfying one of the following:

- The collapse of the nonseismic structure will not cause the nonseismic structure to strike a seismic Category I structure, system or component.
- The collapse of the nonseismic structure will not impair the integrity of seismic Category I structures, systems or components.
- The structure is classified as seismic Category II and is analyzed and designed to prevent its collapse under the safe shutdown earthquake.

The structures adjacent to the nuclear island are the annex building, the radwaste building, and the turbine building.

3.7.2.8.1 Annex Building

The annex building is classified as seismic Category II. The structural configuration is shown in Figure 3.7.2-19. The annex building is analyzed for the safe shutdown earthquake assuming a range of soil properties for the layer above rock at the level of the nuclear island foundation. Seismic input is defined by response spectra applied at the base of a dynamic model of the annex building. The horizontal spectra are obtained from the 2D SASSI analyses and account for soil-structure and structure-soil-structure interaction. Input in the east-west direction uses the response spectra obtained from the two dimensional analyses for the annex building mat. Input in the north-south direction uses the response spectra obtained from the two dimensional analyses for the turbine building mat. Vertical input is obtained from 2D FLUSH finite element soil-structure interaction analyses. The seismic response spectra input at the base of the annex building are the envelopes of the range of soil sites and also envelope the AP1000 design free field ground spectra shown in Figures 3.7.1-1 and 3.7-1-2. The envelope of the maximum building response acceleration values is applied as equivalent static loads to a more detailed static model.

The minimum space required between the annex building and the nuclear island to avoid contact is obtained by absolute summation of the deflections of each structure obtained from either a time history or a response spectrum analysis for each structure. The maximum displacement of the roof of the annex building is 1.6 inches in the east-west direction. The minimum clearance between the structural elements of the annex building above grade and the nuclear island is 4 inches.

3.7.2.8.2 Radwaste Building

The radwaste building is classified as nonseismic and is designed to the seismic requirements of the Uniform Building Code, Zone 2A with an Importance Factor of 1.25. As shown in the radwaste building general arrangement in Figure 1.2-22, it is a small steel framed building. If it were to impact the nuclear island or collapse in the safe shutdown earthquake, it would not impair the integrity of the reinforced concrete nuclear island. The minimum clearance between the structural elements of the radwaste building above grade and the nuclear island is 4 inches.

Three methods are used to demonstrate that a potential radwaste building impact on the nuclear island during a seismic event will not impair its structural integrity:

- The maximum kinetic energy of the impact during a seismic event considers the maximum radwaste building and nuclear island velocities. The total kinetic energy is considered to be absorbed by the nuclear island and converted to strain energy. The deflection of the nuclear island is less than 0.2″. The shear forces in the nuclear island walls are less than the ultimate shear strength based on a minus one standard deviation of test data.

- Stress wave evaluation shows that the stress wave resulting from the impact of the radwaste building on the nuclear island has a maximum compressive stress less than the concrete compressive strength.

- An energy comparison shows that the kinetic energy of the radwaste building is less than the kinetic energy of tornado missiles for which the exterior walls of the nuclear island are designed.

3.7.2.8.3 Turbine Building

The turbine building is classified as nonseismic. As shown on the turbine building general arrangement in Figures 1.2-23 through 1.2-30, the major structure of the turbine building is separated from the nuclear island by approximately 18 feet. Floors between the turbine building main structure and the nuclear island provide access to the nuclear island. The floor beams are supported on the outside face of the nuclear island with a nominal horizontal clearance of 12 inches between the structural elements of the turbine building and the nuclear island. These beams are of light construction such that they will collapse if the differential deflection of the two buildings exceeds the clearance and will not jeopardize the two foot thick walls of the nuclear island. The roof in this area rests on the roof of the nuclear island and could slide relative to the roof of the nuclear island in a large earthquake. The seismic design is upgraded from Zone 2A, Importance Factor of 1.25, to Zone 3 with an Importance Factor of 1.0 in order to provide margin against collapse during the safe shutdown earthquake. The turbine building is an eccentrically braced steel frame structure designed to meet the following criteria:

- The turbine building is designed in accordance with ACI-318 for concrete structures and with AISC for steel structures. Seismic loads are defined in accordance with the 1997 Uniform Building Code provisions for Zone 3 with an Importance Factor of 1.0. For an eccentrically braced structure the resistance modification factor is 7 (UBC-97, reference 1) using strength design. When using allowable stress design, the allowable stresses are not

increased by one third for seismic loads and the resistance modification factor is increased to 10 (UBC-91).

- The nominal horizontal clearance between the structural elements of the turbine building above grade and the nuclear island and annex building is 12 inches.

- The design of the lateral bracing system complies with the seismic requirements for eccentrically braced frames given in section 9.3 of the AISC Seismic Provisions for Structural Steel Buildings (reference 34). Quality assurance is in accordance with ASCE 7-98 (reference 35) for the lateral bracing system.

3.7.2.9 Effects of Parameter Variations on Floor Response Spectra

Seismic model uncertainties due to, among other things, uncertainties in material properties, mass properties, damping values, the effect of concrete cracking, and the modeling techniques are accounted for in the widening of floor response spectra, as described in subsection 3.7.2.5. The effect of cracking of the concrete-filled structural modules inside containment due to thermal loads is discussed in subsection 3.8.3.4.2.

3.7.2.10 Use of Constant Vertical Static Factors

The vertical component of the safe shutdown earthquake is considered to occur simultaneously with the two horizontal components in the seismic analyses. Therefore, constant vertical static factors are not used for the design of seismic Category I structures.

3.7.2.11 Method Used to Account for Torsional Effects

The seismic analysis models of the nuclear island incorporate the mass and stiffness eccentricities of the seismic Category I structures and the torsional degrees of freedom. An accidental torsional moment is included in the design of the nuclear island structures. The accidental torsional moment due to the eccentricity of each mass is determined using the following:

- Horizontal mass properties of the building stick models shown in Figures 3.7.2-4, 3.7.2-5, and 3.7.2-6.

- The maximum absolute value of the north-south and east-west nodal accelerations shown in Tables 3.7.2-5, 3.7.2-6, and 3.7.2-7.

- An assumed accidental eccentricity equal to ±5 percent of the maximum building dimensions at the elevation of the mass. This was increased to ±10 percent to apply an additional torsional load to the model so that the member forces in the stick model would match those from the time history analyses.

- The torsional moments due to eccentricities of the masses at each elevation are assumed to act in the same direction on each structure.

- The torsional moments are applied in two load cases:
  - TOR-NS Case, T_{NS} – accidental torsional moment caused by a Y-eccentricity of the mass during a shock in the X direction
  - TOR-EW Case, T_{EW} – accidental torsional moment caused by a X-eccentricity of the mass during a shock in the Y direction
- The results of each of these torsional load cases are combined absolutely with the results of the corresponding translation acceleration case. The three directions are then combined as described in subsection 3.7.2.6, i.e.

$$R = \sqrt{\left(\left|A_{NS}\right| + \left|T_{NS}\right|\right)^2 + \left(\left|A_{EW}\right| + \left|T_{EW}\right|\right)^2 + A_{VT}^{\ 2}}$$

or

$$R = \text{Fact}(1)\left[\text{SIGN}\left(A_{NS}\right)\left(\left|A_{NS}\right| + \left|T_{NS}\right|\right)\right]$$

$$+ \text{Fact}(2)\left[\text{SIGN}\left(A_{EW}\right)\left(\left|A_{EW}\right| + \left|T_{EW}\right|\right)\right] + \text{Fact}(3)A_{VT}$$

where:

R	=	Seismic response (member force, stress or deflection)
A_{NS}	=	NS-Shock Case, response due to x-translation acceleration
A_{EW}	=	EW-Shock Case, response due to y-translation acceleration
A_{VT}	=	VT-Shock Case, response due to z-translation acceleration
Fact(i)	=	[±1.0, ±0.4, ±0.4]
SIGN()	=	Sign of variable in parentheses

3.7.2.12 Methods for Seismic Analysis of Dams

Seismic analysis of dams is site specific design.

3.7.2.13 Determination of Seismic Category I Structure Overturning Moments

Subsection 3.8.5.5.4 describes the effects of seismic overturning moments.

3.7.2.14 Analysis Procedure for Damping

Subsection 3.7.1.3 presents the damping values used in the seismic analyses. [*For structures comprised of different material types, the composite modal damping approach utilizing the strain energy method is used to determine the composite modal damping values.*]* Subsection 3.7.2.4 presents the damping values used in the soil-structure interaction analysis.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

3.7.3 Seismic Subsystem Analysis

This subsection describes the seismic analysis methodology for subsystems, which are those structures and components that do not have an interface with the soil-structure interaction analyses. Structures and components considered as subsystems include the following:

- Structures, such as floor slabs, walls, miscellaneous steel platforms and framing
- Equipment modules consisting of components, piping, supports, and structural frames
- Equipment including vessels, tanks, heat exchangers, valves, and instrumentation
- Distributive systems including piping and supports, electrical cable trays and supports, HVAC ductwork and supports, instrumentation tubing and supports, and conduits and supports

Subsection 3.9.2 describes dynamic analysis methods for the reactor internals. Subsection 3.9.3 describes dynamic analysis methods for the primary coolant loop support system. Subsection 3.7.2 describes the analysis methods for seismic systems, which are those structures and components that are considered with the foundation and supporting media. Section 3.2 includes the seismic classification of building structures, systems, and components.

3.7.3.1 Seismic Analysis Methods

The methods used for seismic analysis of subsystems include, modal response spectrum analysis, time-history analysis, and equivalent static analysis. The methods described in this subsection are acceptable for any subsystem. The particular method used is selected by the designer based on its appropriateness for the specific item. Items analyzed by each method are identified in the descriptions of each method in the following paragraphs.

3.7.3.2 Determination of Number of Earthquake Cycles

Seismic Category I structures, systems, and components are evaluated for one occurrence of the safe shutdown earthquake (SSE). In addition, subsystems sensitive to fatigue are evaluated for cyclic motion due to earthquakes smaller than the safe shutdown earthquake. Using analysis methods, these effects are considered by inclusion of seismic events with an amplitude not less than one-third of the safe shutdown earthquake amplitude. The number of cycles is calculated based on IEEE-344-1987 (Reference 16) to provide the equivalent fatigue damage of two full safe shutdown earthquake events with 10 high-stress cycles per event. Typically, there are five seismic events with an amplitude equal to one-third of the safe shutdown earthquake response. Each of the one-third safe shutdown earthquake events has 63 high-stress cycles. [*For ASME Class 1 piping, the fatigue evaluation is performed based on five seismic events with an amplitude equal to one-third of the safe shutdown earthquake response. Each event has 63 high-stress cycles.*]*

When seismic qualification is based on dynamic testing for structures, systems, or components containing mechanisms that must change position in order to function, operability testing is performed for the safe shutdown earthquake preceded by one or more earthquakes. The number of preceding earthquakes is calculated based on IEEE-344-1987 (Reference 16) to provide the

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

equivalent fatigue damage of one safe shutdown earthquake event. Typically, the preceding earthquake is one safe shutdown earthquake event or five one-half safe shutdown earthquake events.

3.7.3.3 Procedure Used for Modeling

The dynamic analysis of any complex system requires the discretization of its mass and elastic properties. This is accomplished by concentrating the mass of the system at distinct characteristic points or nodes, and interconnecting them by a network of elastic springs representing the stiffness properties of the systems. The stiffness properties are computed either by hand calculations for simple systems or by finite element methods for more complex systems.

Nodes are located at mass concentrations and at additional points within the system. They are selected in such a way as to provide an adequate representation of the mass distribution and high-stress concentration points of the system.

At each node, degrees of freedom corresponding to translations along three orthogonal axes, and rotations about these axes are assigned. The number of degrees of freedom is reduced by the number of constraints, where applicable. For equipment qualification, reduced degrees of freedom are acceptable provided that the analysis adequately and conservatively predicts the response of the equipment.

The size of the model is reviewed so that a sufficient number of masses or degrees of freedom are used to compute the response of the system. A model is considered adequate provided that additional degrees of freedom do not result in more than a 10 percent increase in response, or the number of degrees of freedom equals or exceeds twice the number of modes with frequencies less than 33 hertz.

Dynamic models of floor and roof slabs and miscellaneous steel platforms and framing include masses equal to 25 percent of the floor live load or 75 percent on the roof snow load, whichever is applicable.

Dynamic models are prepared for the following seismic Category I steel structures. Response spectrum or time history analyses are performed for structural design.

- Passive containment cooling valve room (room number 12701)
- Steel framing around steam generators
- Containment air baffle

Seismic input for the subsystem and component design are the enveloped floor response spectra described in subsection 3.7.2.5 or the response time histories as described in subsection 3.7.2.1. Where amplified response spectra are required on the subsystem for design of components, such as for use in the decoupled analyses of piping or components described in subsection 3.7.3.8.3, the amplified response spectra are generated and enveloped as described in subsection 3.7.2.5.

3.7.3.4 Basis for Selection of Frequencies

The effect of the building amplification on equipment and components is addressed by the floor response spectra method or by a coupled analysis of the building and equipment. Certain components are designed for a natural frequency greater than 33 hertz. In those cases where it is practical to avoid resonance, the fundamental frequencies of components and equipment are selected to be less than one-half or more than twice the dominant frequencies of the support structure.

3.7.3.5 Equivalent Static Load Method of Analysis

[*The equivalent static load method involves equivalent horizontal and vertical static forces applied at the center of gravity of various masses. The equivalent force at a mass location is computed as the product of the mass and the seismic acceleration value applicable to that mass location. Loads, stresses, or deflections, obtained using the equivalent static load method, are adjusted to account for the relative motion between points of support when significant.*]*

3.7.3.5.1 Single Mode Dominant or Rigid Structures or Components

For rigid structures and components, or for cases where the response can be classified as single mode dominant, the following procedures are used. Examples of these systems, structures, and components are equipment, and piping lines, instrumentation tubing, cable trays, HVAC, and floor beams modeled on a span by span basis.

- For rigid systems, structures, and components (fundamental frequency $\geq$ 33 hertz), an equivalent seismic load is defined for the direction of excitation as the product of the component mass and the zero period acceleration value obtained from the applicable floor response spectra.

- A rigid component (fundamental frequency $\geq$ 33 hertz), whose support can be represented by a flexible spring, can be modelled as a single degree of freedom model in the direction of excitation (horizontal or vertical directions). The equivalent static seismic load for the direction of excitation is defined as the product of the component mass and the seismic acceleration value at the natural frequency from the applicable floor response spectra. If the frequency is not determined, the peak acceleration from the applicable floor response spectrum is used.

[• *If the component has a distributed mass whose dynamic response will be single mode dominant, the equivalent static seismic load for the direction of excitation is defined as the product of the component mass and the seismic acceleration value at the component natural frequency from the applicable floor response spectra times a factor of 1.5. A factor of less than 1.5 may be used if justified. Static factors smaller than 1.5 are not used for piping systems.*]* A factor of 1.0 is used for structures or equipment that can be represented as uniformly loaded cantilever, simply supported, fixed-simply supported, or fixed-fixed beams (References 10 and 11) when the fundamental frequency is higher than the peak acceleration frequency associated with the applicable floor response spectrum. If the frequency is not determined, the peak acceleration from the applicable floor response spectrum is used.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

3.7.3.5.2 Multiple Mode Dominant Response

This procedure applies to piping, instrumentation tubing, cable trays, and HVAC that are multiple span models. The equivalent static load method of analysis can be used for design of piping systems, instrumentation and supports that have significant responses at several vibrational frequencies. In this case, [*a static load factor of 1.5 is applied to the peak accelerations of the applicable floor response spectra. For runs with axial supports which are rigid in the axial direction (fundamental frequency greater than or equal to 33 hertz), the acceleration value of the mass of piping in its axial direction may be limited to 1.0 times its calculated spectral acceleration value. The spectral acceleration value is based on the frequency of the piping system along the axial direction. The relative motion between support points is also considered.*]*

3.7.3.6 Three Components of Earthquake Motion

[*Two horizontal components and one vertical component of seismic response spectra are employed as input to a modal response spectrum analysis.*]* The spectra are associated with the safe shutdown earthquake. In the response spectrum and equivalent static analyses, the effects of the three components of earthquake motion are combined using one of the following methods:

[• *The peak responses due to the three earthquake components from the response spectrum analyses are combined using the square root of the sum of squares (SRSS) method.*

- *The peak responses due to the three earthquake components are combined directly, using the assumption that when the peak response from one component occurs, the responses from the other two components are 40 percent of the peak (100 percent-40 percent-40 percent method). Combinations of seismic responses from the three earthquake components, together with variations in sign (plus or minus), are considered. This method is not used for piping systems.*

One set of three mutually orthogonal artificial time histories is used when time-history analyses are performed. The components of earthquake motion specified in the three directions are statistically independent and applied simultaneously. When this method is used, the responses from each of the three components of motion are combined algebraically at each time step.]*

In addition, an optional method for combining the response of the three components of earthquake motion is presented in the following paragraphs.

[*The time-history safe shutdown earthquake analysis of a subsystem can be performed by simultaneously applying the displacements and rotations at the interface point(s) between the subsystem and the system. These displacements and rotations are the results obtained from a model of a larger subsystem or a system that includes a simplified representation of the subsystem. The time-history safe shutdown earthquake analysis of the system is performed by applying three mutually orthogonal and statistically independent, artificial time histories.*]* Possible examples of the use of this method of seismic analysis include the following:

- The subsystem analysis is a flexible floor or miscellaneous structural steel frame. The corresponding system analysis is the soil-structure interaction analysis of the nuclear island structures.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- The subsystem analysis is the primary loop piping system and interior concrete building structure. The interface point is the top of the basemat. The corresponding system analysis is the soil-structure interaction analysis of the nuclear island structures.

- The subsystem analysis is the reactor coolant pump and internal components. The interface points are the welds on the pump suction and discharge nozzles. The corresponding system analysis is the primary loop piping system and interior concrete building structure.

3.7.3.7 Combination of Modal Responses

[*For the seismic response spectra analyses, the zero period acceleration cut-off frequency is 33 hertz. High frequency or rigid modes are considered using the left-out-force method or the missing mass method*]* described in subsection 3.7.3.7.1. The method to combine the low frequency modes is described in subsection 3.7.3.7.2. [*The rigid mode results in the three perpendicular directions of the seismic input are combined by the SRSS method. The resultant response of the rigid modes is combined by SRSS with the flexible mode results.*]* The combination of modal responses in time history analyses of piping systems is described in subsection 3.7.3.17. Modal responses in time history analyses of other subsystems are combined as described in subsection 3.7.2.6.

3.7.3.7.1 Combination of High-Frequency Modes

This subsection describes alternative methods of accounting for high-frequency modes (generally greater than 33 hertz) in seismic response spectrum analysis. Higher-frequency modes can be excluded from the response calculation if the change in response is less than or equal to 10 percent.

3.7.3.7.1.1 Left-Out-Force Method or Missing Mass Correction for High Frequency Modes

The left-out-force method is based on the Left-Out-Force Theorem. This theorem states that for every time history load there is a frequency, f_r, called the "rigid mode cutoff frequency" above which the response in modes with natural frequencies above f_r will very closely resemble the applied load at each instant of time. These modes are called "rigid modes." [*The left-out-force method is used in program PIPESTRESS.*]*

The left-out-force vector, $\{Fr\}$, is calculated based on lower modes:

$$\{Fr\} = \left[1 - \Sigma M e_j e_j^T\right] f(t)$$

where:

$f(t)$ = the applied load vector
M = the mass matrix
e_j = the eigenvector

Note that Σ is only for all the flexible modes, not including the rigid modes.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

In the response spectra analysis, the total inertia force contribution of higher modes can be interpreted as:

$$\{Fr\} = Am[M]\left[\{r\} - \Sigma P_j e_j\right]$$

where:

Am = the maximum spectral acceleration beyond the flexible modes
[M] = the mass matrix
{r} = the influence vector or displacement vector due to unit displacement
P_j = participation factor

Since,

$$P_j = e_j{}^T [M]\{r\}, \{Fr\} = Am[M]\{r\}\left[1 - \Sigma M e_j e_j{}^T\right]$$

[*In PIPESTRESS, the low frequency modes are combined by one of the Regulatory Guide 1.92 methods in the response spectrum analysis.*]* For each support level, there is a pseudo-load vector or left-out-force vector in the X, Y and Z directions. These left-out-force vectors are used to generate left-out-force solutions which are multiplied by a scalar amplitude equal to a magnification factor specified by the user. This factor is usually the ZPA (zero period acceleration) of the response spectrum for the corresponding direction. The resultant low frequency responses are combined by square root of the sum of the squares with the high frequency responses (rigid modes results).

[*In GAPPIPE, the results from the high frequency responses are also combined by the square root of the sum of the squares with those from the resultant loads contributed by lower modes.*]* The missing mass correction for an independent support motion or multiple response spectra analysis is exactly the same as that for the single enveloped response spectrum analysis except that Am used is the envelope of all the zero period accelerations of all the independent support inputs.

3.7.3.7.1.2 SRP 3.7.2 Method

[*The method described in SRP Section 3.7.2 may also be used for combination of high-frequency modes.*]*

The following is the procedure for incorporating responses associated with high-frequency modes.

Step 1 Determine the modal responses only for those modes having natural frequencies less than that at which the spectral acceleration approximately returns to the zero period acceleration (33 hertz for the Regulatory Guide 1.60 response spectra). Combine such modes according to the methods discussed in subsection 3.7.3.7.2.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Step 2 For each degree of freedom included in the dynamic analysis, determine the fraction of degree of freedom mass included in the summation of all modes included in Step 1. This fraction d_i for each degree of freedom is given by:

$$d_i = \sum_{n=1}^{N} C_n \text{ x } \phi_{n,i}$$

where:

n = order of mode under consideration
N = number of modes included in Step 1
$\phi_{n,i}$ = nth natural mode of the system

C_n is the participation factor given by:

$$C_n = \frac{(\phi_n)^T [m] (1)}{(\phi_n)^T [m] (\phi_n)}$$

Next, determine the fraction of degree of freedom mass not included in the summation of these modes:

$$e_i = d_i - \delta_{ij}$$

where δ_{ij} is the Kronecker delta, which is 1 if degree of freedom i is in the direction of the earthquake motion and 0 if degree of freedom i is a rotation or not in the direction of the earthquake input motion.

If, for any degree of freedom i, the absolute value of this fraction e_i exceeds 0.1, the response from higher modes is included with those included in Step 1.

Step 3 Higher modes can be assumed to respond in phase with the zero period acceleration and, thus, with each other. Hence, these modes are combined algebraically, which is equivalent to pseudostatic response to the inertial forces from these higher modes excited at the zero period acceleration. The pseudostatic inertial forces associated with the summation of all higher modes for each degree of freedom i are given by:

$$P_i = ZPA \text{ x } M_i \text{ x } e_i$$

where:

P_i = force or moment to be applied by degree of freedom i
M_i = mass or mass moment of inertia associated with degree of freedom i.

The subsystem is then statically analyzed for this set of pseudo static inertial forces applied to all degrees of freedom to determine the maximum responses associated with high-frequency modes not included in Step 1.

Step 4 The total combined response to high-frequency modes (Step 3) is combined by the square root of sum of the squares method with the total combined response from lower-frequency modes (Step 1) to determine the overall structural peak responses.

3.7.3.7.2 Combination of Low-Frequency Modes

This subsection describes the method for combining modal responses in the seismic response spectra analysis. [*The total unidirectional seismic response for subsystems is obtained by combining the individual modal responses using the square root sum of the squares method. For subsystems having modes with closely spaced frequencies, this method is modified to include the possible effect of these modes. For piping systems, the methods in Regulatory Guide 1.92 are used for modal combinations.*]* For other subsystems, the methods in Regulatory Guide 1.92 or the following alternative methods may be used. [*The groups of closely spaced modes are chosen so that the differences between the frequencies of the first mode and the last mode in the group do not exceed 10 percent of the lower frequency.*

Combined total response for systems having such closely spaced modal frequencies is obtained by adding to the square root sum of squares of all modes the product of the responses of the modes in each group of closely spaced modes and coupling factor.]* This can be represented mathematically as:

$$R_T^2 = \sum_{i=1}^{N} R_i^2 + 2\sum_{j=1}^{S} \sum_{k=Mj}^{Nj-1} \sum_{\ell=k+1}^{Nj} R_k\, R_\ell\, \varepsilon_{k\ell}$$

where:

R_T = total unidirectional response
R_i = absolute value of response of mode i
N = total number of modes considered
S = number of groups of closely spaced modes
M_j = lowest modal number associated with group j of closely spaced modes
N_j = highest modal number associated with group j of closely spaced modes
$\varepsilon_{k\ell}$ = coupling factor, defined as follows:

$$\varepsilon_{k\ell} = \left(1 + \frac{\left(w'_k - w'_\ell\right)^2}{\left(\beta'_k\, w_k + \beta'_\ell\, w_\ell\right)^2}\right)^{-1}$$

and,

$$w'_k = w_k \left[1 - \left(\beta_k\right)^2\right]^{1/2}$$

$$\beta'_k = \beta_k + \frac{2}{w_k\, t_d}$$

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

where:

w_k = frequency of closely spaced mode k
β_k = fraction of critical damping in closely spaced mode k
t_d = duration of the earthquake (= 30 seconds)

[*Alternatively, a more conservative grouping method can be used in the seismic response spectra analyses. The groups of closely spaced modes are chosen so that the difference between two frequencies is no greater than 10 percent.*]* Therefore,

$$R_T^{\,2} = \sum_{i=1}^{N} R_i^{\,2} + 2\Sigma\, \varepsilon_{k\ell}\, R_k\, R_\ell$$

where:

$$\frac{|\, w_k - w_\ell \,|}{w_\ell} \leq 0.1$$

All other terms for the modal combination remain the same. The 10 percent grouping method is more conservative than the grouping method because the same mode can appear in more than one group.

In addition to the above methods, any of the other methods in Regulatory Guide 1.92 may be used for modal combination.

[*3.7.3.8 Analytical Procedure for Piping*

This subsection describes the modeling methods and analytical procedures for piping systems.

The piping system is modeled as beam elements with lump masses connected by a network of elastic springs representing the stiffness properties of the piping system. Concentrated weights such as valves or flanges are also modeled as lump masses. The effects of torsion (including eccentric masses), bending, shear, and axial deformations, and effects due to the changes in stiffness values of curved members are accounted for in the piping dynamic model.

The lump masses are selected so that the maximum spacing is not greater than the length that would produce a natural frequency equal to the zero period acceleration (ZPA) frequency of the seismic input when calculated based on a simply supported beam. As a minimum, the number of degrees of freedom is equal to twice the number of modes with frequencies less than the zero period acceleration frequency.

The piping system analysis model includes the effect of piping support mass when the contributory mass of the support is greater than 10 percent of the total mass of the effected piping spans. The contributory mass of the support is the portion of the support mass that is attached to the piping; such as clamps, bolts, trunnions, struts, and snubbers. Supports that are not directly attached to the piping, such as box frames, need not be considered for mass effects. The mass of

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

the applicable support will not affect the response of the system in the supported direction, therefore only the unsupported direction needs to be considered. Based on this reasoning, the mass of full anchors can be neglected. The total mass of each effected piping span includes the mass of the piping, fluid contents, insulation, and any concentrated masses (for example, valves or flanges) between the adjacent supports in each unrestrained direction on both sides of the applicable support. For example; the contributory mass of an X direction support must be compared to the mass of the piping spans in the unrestrained Y and Z directions. A contributory support mass that is less than 10 percent of the masses of the effected spans will have insignificant effect on the response of the piping system and can be neglected.

The stiffness matrix of the piping system is calculated based on the stiffness values of the pipe elements and support elements. Minimum rigid or calculated support stiffness values are used (see subsections 3.9.3.1.5 and 3.9.3.4). When the support deflections are limited to 1/8 inches in the combined faulted condition, minimum rigid support stiffness values are used. If the combined faulted condition deflection for any support exceeds 1/8 inches, calculated support stiffness values are used for the piping system.

Valves, equipment and piping modules are considered as rigid if the natural frequencies are greater than 33 hertz. Valves with lower frequencies are included in the piping system model. See subsection 3.7.3.8.2.1 for flexible equipment and subsection 3.7.3.8.3 for flexible modules.

See subsection 3.9.3.1.4 for the primary loop piping and support system.]*

3.7.3.8.1 Supporting Systems

This subsection deals with the analysis of piping systems that provide support to other piping systems. [*The supported piping system may be excluded from the analysis of the supporting piping system when the ratio of the supported pipe to supporting pipe moment of inertia is less than or equal to 0.04.*

If the ratio of the run piping outside diameter to the branch piping outside diameter (nominal pipe size) exceeds or equals 3.0, the branch piping can be excluded from the analysis of the run piping. The mass and stiffness effects of the branch piping are considered as described below.

Stiffness Effect

The stiffness effect of the decoupled branch pipe is considered significant when the distance from the run pipe outside diameter to the first rigid or seismic support on the decoupled branch pipe is less than or equal to one half the deadweight span of the branch pipe (given in ASME III Code Subsection NF).

Mass Effect

Considering one direction at a time, the mass effect is significant when the weight of half the span (from the decoupling point) of the branch pipe in one direction is more than 20 percent the weight of the main run pipe span in the same direction. Concentrated weights in the branch pipe are considered. A branch pipe span in x direction is the span between the decoupled branch point and the first seismic or rigid support in the x direction. A main run pipe span in the x direction is

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

the piping bounded by the first seismic or rigid support in the x direction on both sides of the decoupled branch point. Similarly, the same definition applies to the spans in other directions (y and z).

If the calculated branch pipe weight is less than 20 percent but more than 10 percent of the main run pipe weight, this weight is lumped at the decoupling point of the run pipe for the run pipe analysis. This weight can be neglected if it is less than 10 percent of the main run pipe weight.

Required Coupled Branch Piping

If the stiffness and/or mass effects are considered significant, the branch piping is included in the piping analysis for the run pipe analysis. The portion of branch piping considered in the analysis adequately represents the behavior of the run pipe and branch pipe. The branch line model ends in one of the following ways:

- *First six-way anchor*
- *Four rigid/seismic supports in each of the three perpendicular directions*
- *Rigidly supported zone as described in subsection 3.7.3.13.4.2*]*

3.7.3.8.2 Supported Systems

This subsection deals with the analysis of piping systems that are supported by other piping systems or by equipment.

3.7.3.8.2.1 Large Diameter Auxiliary Piping

[*This subsection deals with ASME Class 1 piping larger than 1-inch nominal pipe size and ASME Class 2 and 3 piping with nominal pipe size larger than 2 inches. The response spectra methodology is used.*

When the supporting system is a piping system, the supported pipe (branch) can be decoupled from the supporting pipe (run) when the ratio of the run piping nominal pipe size to branch pipe nominal pipe size is greater than or equal to three to one. Decoupling can also be done when the moment of inertia of the branch pipe is less than or equal to 4 percent of the moment of inertia of the run pipe.

During the analysis of the branch piping, resulting values of tee anchor reactions are checked against the capabilities of the tee.

The seismic inertia effects of equipment and piping that provide support to supported (branch) piping systems are considered when significant. When the frequency of the supporting equipment is less than 33 hertz. then either a coupled dynamic model of the piping and equipment is used, or the amplified response spectra at the equipment connection point is used with a decoupled model

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

of the supported piping. When supported piping is supported by larger piping, one of the following methods is used:

- *A coupled dynamic model of the supported piping and the supporting piping*
- *Amplified response spectra at the connection point to the supporting piping with a decoupled model of the supported piping*]*

3.7.3.8.2.2 Small-Diameter Auxiliary Piping

[*This subsection deals with ASME Code Class 1 piping equal to or less than 1-inch nominal pipe size and ASME Class 2 and 3 piping with nominal pipe sizes less than or equal to 2 inches. This includes instrumentation tubing. These piping systems may be supported by equipment or primary loop piping or other auxiliary piping or both. The response spectra or equivalent static load methodology is used. One of the following methods may be used for these systems:*

- *Same method as described in subsection 3.7.3.8.2.1*
- *Equivalent static analysis based on appropriate load factors applied to the response spectra acceleration values*]*

The Combined License applicants will complete the final design of the small-bore piping and address the as-built reconciliation in accordance with the criteria outlined in subsections 3.9.3 and 3.9.8.2.

3.7.3.8.3 Piping Systems on Modules

Many portions of the systems for the AP1000 are assembled as modules offsite and shipped to the plant as completed units. This method of construction does not result in any unique requirements for the analysis of these structures, systems, or components. Existing industry standards and regulatory requirements and guidelines are appropriate for the evaluation of structures, systems, and components included in modules.

The modules are constructed using a structural steel framework to support the equipment, pipe, and pipe supports in the module. The structural steel framework is designed as part of the building structure according to the criteria given in subsection 3.8.4.

One exception is the pressurizer and safety relief valve module, which is attached to the top of the pressurizer. For this module the structures and piping arrangements support valves off the pressurizer and not the building structure. The structural steel frame is designed as a component support according to ASME Code, Section III, Subsection NF. [*Piping in modules is routed and analyzed in the same manner as in a plant not employing modules. Piping is analyzed from anchor point to anchor point, which are not necessarily at the boundaries of the module.*]* This is consistent with the manner in which room walls are treated in a nonmodule plant.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

[*The supported piping or component may be decoupled from the seismic analysis of the structural frame based on the following criteria. The mass ratio, Rm, and the frequency ratio, Rf, are defined as follows:*

- *Rm = mass of supported component or piping/mass of supporting structural frame*
- *Rf = frequency of the component or piping/frequency of the structural frame*

Decoupling may be done when:

- *Rm < 0.01, for any Rf, or*
- *Rm ≥ 0.01 and ≤ 0.10, if Rf ≤ 0.8 or if Rf is ≥ 1.25.*

In addition, supported piping may be decoupled if analysis shows that the effect on the structural frame is small, that is, when the change in response is less than 10 percent. When piping or components are decoupled from the analysis of the frame, the contributory mass of the piping and components is included as a rigid mass in the model of the structural frame.]*

When piping or components are decoupled from the analysis of the frame using the preceding criteria, the effect of the frame is accounted for in the analysis of the decoupled components or piping. Either an amplified response spectra or a coupled model is used. The amplified response spectra are obtained from the time history safe shutdown earthquake analysis of the frame. The coupled model consists of a simplified mass and stiffness model of the frame connected to the seismic model of the components or piping.

Alternative criteria may be applied to simple frames that behave as pipe support miscellaneous steel. Decoupling may be done when the deflection of the frame due to combined faulted condition loading is less than or equal to 1/8 inch. These deflections are defined with respect to the structure to which the structural frame is attached. The stiffness of the intervening elements between the frame and the supported piping or component is considered as follows: Rigid stiffness values are used for fabricated supports, and vendor stiffness values are used for standard supports such as snubbers and rigid gapped supports. The mass of the structural frame is evaluated as a self-weight excitation loading on the frame and the structures supporting the frame. The same approach is used for pipe support miscellaneous steel, as described in subsection 3.9.3.4.

When the supported components or piping cannot be decoupled, they are included in the analysis model of the structural frame. The interaction between the piping and the frame is incorporated by including the appropriate stiffness and mass properties of the components, piping, and frame in the coupled model.

[*3.7.3.8.4 Piping Systems with Gapped Supports*

This subsection describes the analysis methods for piping systems with rigid gapped supports. These supports may be used to minimize the number of pipe support snubbers and the corresponding inservice testing and maintenance activities.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

The analysis consists of an iterative response spectra analysis of the piping and support system. Iterations are performed to establish calculated piping displacements that are compatible with the stiffness and gap of the rigid gapped supports. The results of the computer program GAPPIPE, which uses this methodology, are supported with test data (Reference 13).

The method implemented in GAPPIPE to analyze piping systems supported by rigid gapped supports is based on the equivalent linearization technique. GAPPIPE analysis is performed whenever snubber supports are replaced by rigid gapped supports.

The basis of the concept is to find an equivalent linear spring with a response-dependent stiffness for each nonlinear rigid gapped support, or limit stop, in the mathematical model of the piping system. The equivalent linearized stiffness minimizes the mean difference in force in the support between the equivalent spring and the corresponding original gapped support. The mean difference is estimated by an averaging process in the time domain, that is, across the response duration, using the concept of random vibration. Details of the design and analysis methods and modeling assumptions are described in Reference 12.]*

3.7.3.9 Combination of Support Responses

This subsection describes alternative methods for combining the responses from the individual support or attachment points that connect the supported system or subsystem to the supporting system or subsystem. There are two aspects to the responses from the support or attachment points: seismic anchor motions and envelope or multiple-input response spectra methodology.

Seismic Anchor Motions – The response due to differential seismic anchor motions is calculated using static analysis (without including a dynamic load factor). In this analysis, the static model is identical to the static portion of the dynamic model used to compute the seismic response due to inertial loading. In particular, the structural system supports in the static model are identical to those in the dynamic model.

[*The effect of relative seismic anchor displacements is obtained either by using the worst combination of the peak displacements or by proper representation of the relative phasing characteristics associated with different support inputs. For components supported by a single concrete building (coupled shield and auxiliary buildings, or containment internal structures), the seismic motions at all elevations above the basemat are taken to be in phase. When the component supports are in the same structure, the relative seismic anchor motions are small and the effects are neglected. This is applicable to building structures and to those supplemental steel frames that are rigid in comparison to the components. Supplemental steel frames that are flexible can have significant seismic anchor motions which are considered. When the components supports are in different structures, the relative seismic anchor motion between the structures is taken to be out-of-phase and the effects are considered. The results of the modal spectra analysis (multiple input or envelope) are combined with the results from seismic anchor motion by the absolute sum method.*]*

Response Spectra Methods – The envelope broadened uniform-input response spectra can lead to excessive conservatism and unnecessary pipe supports. The peak shifting method and independent support motion spectra method are used to avoid unnecessary conservatism.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Seismic Response Spectra Peak Shifting

The peak shifting method may be used in place of the broadened spectra method, as described below.

Determine the natural frequencies $(f_e)_n$ of the system to be qualified in the broadened range of the maximum spectrum acceleration peak.

If no equipment or piping system natural frequencies exist in the ±15 percent interval associated with the maximum spectrum acceleration peak, then the interval associated with the next highest spectrum acceleration peak is selected and used in the following procedure.

Consider all N natural frequencies in the interval

$$f_j - 0.15f_j \leq (f_e)_n \leq f_j + 0.15f_j$$

where:

f_j = the frequency of maximum acceleration in the envelope spectra
n = 1 to N

The system is then evaluated by performing N + 3 separate analyses using the envelope unbroadened floor design response spectrum and the envelope unbroadened spectrum modified by shifting the frequencies associated with each of the spectral values by a factor of +0.15; -0.15; and

$$\frac{(f_e)_n - f_j}{f_j}$$

where:

n = 1 to N

The results of these separate seismic analyses are then enveloped to obtain the final result desired (e.g., stress, support loads, acceleration, etc.) at any given point in the system. If three different floor response spectrum curves are used to define the response in the two horizontal and the vertical directions, then the shifting of the spectral values as defined above may be applied independently to these three response spectrum curves.

Independent Support Response Spectrum Methods

The use of multiple-input response spectra accounts for the phasing and interdependence characteristics of the various support points. The following alternative methods are used for the AP1000 plant. These are based on the guidelines provided by the "Pressure Vessel Research Committee Technical Committee on Piping Systems" (Reference 14).

[*Envelope Uniform Response Spectra - Method A - The seismic response spectrum that envelopes the supports is used in place of the spectra at each support in the envelope uniform response spectra. Also, the contribution from the seismic anchor motion of the support points is assumed to be in phase and is added algebraically as follows:*

$$q_i = d_i \sum_{j=1}^{N} P_{ij}$$

where:

q_i = *combined displacement response in the normal coordinate for mode i*
d_i = *maximum value of* d_{ij}
d_{ij} = *displacement spectral value for mode i associated with support "j"*
P_{ij} = *participation factor for mode i associated with support j*
N = *number of support points*

Enveloped response spectra are developed as the seismic input in three perpendicular directions of the piping coordinate system to include the spectra at the floor elevations of the attachment points and the piping module or equipment if applicable. The mode shapes and frequencies below the cut-off frequency are calculated in the response spectrum analysis. The modal participation factors in each direction of the earthquake motion and the spectral accelerations for each significant mode are calculated. Based on the calculated mode shapes, participation factors, and spectral accelerations of individual modes, the modal inertia response forces, moments, displacements, and accelerations are calculated. For a given direction, these modal inertia responses are combined based on consideration of closely spaced modes and high frequency modes to obtain the resultant forces, moments, displacements, accelerations, and support loads. The total seismic responses are combined by square-root-sum-of-the-squares method for all three earthquake directions.

Independent Support Motion - Method B - When there are more than one supporting structure, the independent support motion (ISM) method for seismic response spectra may be used.

Each support group is considered to be in a random-phase relationship to the other support groups. The responses caused by each support group are combined by the square-root-sum-of-the-square method. The displacement response in the modal coordinate becomes:

$$q_i = \left[\sum_{j=1}^{N} \left(P_{ij}\, d_{ij} \right)^2 \right]^{1/2}$$

A support group is defined by supports that have the same time-history input. This usually means all supports located on the same floor (or portions of a floor) of a structure.]*

3.7.3.10 Vertical Static Factors

Constant static factors can be used in some cases for the design of seismic Category I subsystems and equipment. The criteria for using this method are presented in subsection 3.7.3.5.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

3.7.3.11 Torsional Effects of Eccentric Masses

[*The methods used to account for the torsional effects of valves and other eccentric masses (for example, valve operators) in the seismic subsystem analyses are as follows:*

- *When valves and other eccentric masses are considered rigid, the mass of the operator and valve body or other eccentric mass are located at their respective center of gravity. The eccentric components (that is, yoke, valve body) are modeled as rigid members.*

- *When valves and other eccentric masses are not considered rigid, the dynamic models are simulated by the lumped masses in discrete locations (that is, center of gravity of valve body and valve operator), coupled by elastic members with properties of the eccentric components.*]*

3.7.3.12 Seismic Category I Buried Piping Systems and Tunnels

[*There are no seismic Category I buried piping systems and tunnels in the AP1000 design.*]*

3.7.3.13 Interaction of Other Systems with Seismic Category I Systems

The safety functions of seismic Category I structures, systems, and components are protected from interaction with nonseismic structures, systems, and components; or their interaction is evaluated. The safety-related systems and components required for safe shutdown are described in Section 7.4. This equipment is located in selected areas of the auxiliary building and inside containment. The primary means of protecting safety-related structures, systems, and components from adverse seismic interactions are discussed in the following paragraphs in the order of preference.

- Separation – separation with the use of physical barriers

- Segregation – routing away from location of seismic Category I systems, structures, and components

- Impact Evaluation – contact with seismic Category I systems, structures, and components may occur, and there is insufficient energy in the impact to cause loss of safety function

- Support as seismic Category II

[*Interaction of connected systems with seismic Category I piping is considered by including the other piping in the analysis of the seismic Category I system.*]* Interaction of piping systems that are adjacent to Category I structures, systems, and components is also considered. This is discussed in subsection 3.7.3.13.4.

The containment and each room outside containment containing safety-related systems or equipment, as identified in Table 3.7.3-1, are reviewed for potential adverse seismic interactions to demonstrate that systems, structures, and components are not prevented from performing their required safe shutdown functions. In addition, the review identifies the protection features required to mitigate the consequences of seismic interaction in an area that contains safety-related equipment.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

The evaluation steps to address seismic interaction taken for each room or building area containing seismic Category I systems, structures, and components are:

1. Define targets susceptible to damage (sensitive targets);
   Sensitive targets are those seismic Category I components for which adverse spatial interaction can result in loss of safety function.

2. Define sources which can potentially interact in an adverse manner with the target.

3. If possible, assure adequate free space to eliminate the possibility of seismically-induced damaging impacts for the sensitive targets.

4. Assess impact effects (interaction) when adequate free space is not present.

5. Correct adverse seismic interaction conditions.

The three-dimensional computer model and composites developed for the nuclear island are used during the design process of the systems and components in the nuclear island, to aid in evaluating and documenting the review for seismic interactions. This review is performed using the design criteria and guidelines described in subsections 3.7.3.13.1 through 3.7.3.13.4.

The seismic interaction review will be updated by the Combined License applicant. This review is performed in parallel with the seismic margin evaluation. The review is based on as-procured data, as well as the as-constructed condition.

3.7.3.13.1 Separation and Segregation

Separation – The general plant arrangement provides physical separation between the seismic Category I and nonseismic structures, systems, and components to the maximum extent practicable in the nuclear island. The objective is to assist in the preclusion of a potential adverse interaction if the nonseismic structures, systems and components were to fail during a seismic event. Whenever possible, nonseismic pipe, electrical raceway, or ductwork is not routed above or adjacent to safety-related equipment, pipe, electrical raceway, or ductwork, thereby eliminating the possibility of seismic interaction.

Workstations and other equipment in the Main Control Room are separated from piping. Further, as stated in subsection 3.2.1.1.2, structures, systems, and components that are located overhead in the Main Control Room are supported as seismic Category II.

Segregation – Where separation by physical means cannot be accomplished and it becomes necessary to locate or route nonseismic structures, systems, and components in or through safety-related areas, the nonseismic structures, systems and components are segregated from the seismic Category I items to the extent practicable.

Nonseismic cabinets are separated or segregated from seismic Category I cabinets. Also, if a cabinet is a source or a target, the cabinet doors must be secured by latches or fasteners to assure they do not open during a seismic event.

3.7.3.13.2 Impact Analysis

Adverse spatial interaction (i.e., loss of structural integrity or function effecting safety) can potentially occur when two items are in close proximity. Adverse spatial interaction can result from contact or impact from overturning. Seismic Category I systems, structures, and components that are sensitive to seismic interaction are identified as potential targets. Sources are structures or components that can have adverse spatial interaction with the seismic Category I systems, structures, and components. Identification and evaluation of spatial interactions includes the following considerations:

- Proximity of the source to the target. That is, the location of the source within the impact evaluation zone (shown in Figure 3.7.3-1)

  If a source is outside the impact evaluation zone, and does not enter this zone if overturning occurs, no adverse spatial interaction can occur with the identified target. If the source is within the impact evaluation zone and the supports of the source fail, the source could free fall, potentially impacting the target.

- Robustness of target

  If a target has significant structural integrity, and its function is not an issue, adverse spatial interaction could not occur with the identified source.

- Energy of impact

  The energy of the source impacting the target may be so low as not to cause adverse spatial interaction with the target.

A specific nonseismic structure, system, or component identified as a source to a specific safety-related component can be acceptable without being supported as seismic Category II, if an analysis demonstrates that the weight and configuration of the source, relative to the target, and the trajectory of the source are such that the interaction would not cause unacceptable damage to the target. For example, a nonseismic instrument tube routed above a seismic Category I electrical cable tray would not pose a hazard and would be acceptable.

Nonseismic equipment can overturn as a result of a safe shutdown earthquake. The trajectory of its fall is evaluated to determine if it poses a potential impact hazard to a safety-related structure, system, or component. If it poses a hazard, the equipment is relocated, or it is supported as described in subsection 3.7.3.13.3.

Nonseismic walls, platforms, stairs, ladders, grating, handrail installations, or other structures next to safety-related structures, systems, and components are evaluated to determine if their failure is credible.

Should a nonseismic structure, system, or component be capable of being dislodged from its supports, the trajectory of its fall is evaluated for potential adverse impacts. If these present a hazard, the structure, system or component is relocated or supported as described in subsections 3.7.3.13.3 and 3.7.3.13.4. Impact is assumed for sources within an impact evaluation

zone around the safety-related equipment. The impact evaluation zone is defined as the envelope around the target for which a source, if located outside of the envelope, would not impact the target during a safe shutdown earthquake in the event the supports of the source were to fail and allow the source to fall. The impact evaluation zone is defined by the volume extending 6 feet horizontally from the perimeter of the seismic Category I object up to a height of 35 feet. The impact evaluation zone above 35 feet is defined by a 10-degree cone radiating vertically from the foot of the object, projected from its perimeter. This definition of the impact evaluation zone is illustrated in Figure 3.7.3-1. The impact evaluation zone need not extend beyond seismic Category I structures such as walls or floor slabs.

The following seismic Category I equipment (potential targets) are not sensitive to piping, HVAC ducts, and cable tray interaction because they are robust to these types of impact:

- Tanks, "heavy" equipment (for example, heat exchangers)
- Mechanical or electrical penetrations
- Heating, ventilation, and air conditioning (HVAC)
- Adjacent piping
- Conduits
- Cable trays
- Structures

3.7.3.13.3 Seismic Category II Supports

Where the preceding approaches of separation, segregation, or impact analysis cannot prevent unacceptable interaction, the source is classified and supported as seismic Category II. The seismic Category II designation provides confidence that these nonseismic structures, systems, and components can withstand the forces of a safe shutdown earthquake in addition to the loading imparted on the seismic Category II supports due to failure of the remaining nonseismically supported portions. This includes nozzle loads from the nonseismic piping. Design methods and stress criteria for systems, structures, and components classified as seismic Category II are the same as for seismic Category I systems, structures, and components, except for piping which is described in subsection 3.7.3.13.4.2. However, the functionality of these seismic Category II sources does not have to be maintained following a safe shutdown earthquake.

HVAC duct and/or cable trays within the impact evaluation zone are seismically supported using the criteria given in Appendices 3F and 3A for seismic Category I assuring that the HVAC and cable tray segments identified as a source will not fall or adversely impact the sensitive target. Adequate free space between the source and target is assured using the load combination that includes the safe shutdown earthquake. The seismic displacement of the HVAC duct and/or cable tray is 6 inches or the calculated displacement.

Nonseismic equipment identified as a source within the impact evaluation zone is supported as seismic Category II. Support seismic loads include seismic inertia loads of the equipment determined as described in subsection 3.7.3.5 and nozzle loads from attached piping determined as described in subsection 3.7.3.13.4.2. Adequate free space is assessed considering a 6-inch deflection envelope for equipment identified as a source, or calculated deflections obtained using the safe shutdown earthquake load combination and elastic analysis.

[*3.7.3.13.4 Interaction of Piping with Seismic Category I Piping Systems, Structures, and Components*

This subsection describes the design methods for piping to prevent adverse spatial interactions.

3.7.3.13.4.1 Seismic Category I Piping

The safe shutdown earthquake piping displacements obtained for the seismic Category I piping are used for the evaluation of seismic interaction with sensitive equipment. Adequate free space between a source and a target is checked adding absolutely the piping safe shutdown earthquake deflection and the safe shutdown earthquake target deflection along with the other loads (e.g., dead weight, thermal) that are in the appropriate design criteria load combinations. Sensitive equipment for piping as the source is seismic Category I equipment shown in Table 3.7.3-2 along with the portion that must be protected ("zone of protection"). Supports may be added to limit seismic movement to eliminate potential adverse interaction.

3.7.3.13.4.2 Seismic Category II Piping

This subsection describes the methods and criteria for piping that is connected to seismic Category I piping. Interaction of seismic Category I piping and nonseismic Category I piping connected to it is achieved by incorporating into the analysis of the seismic Category I system a length of pipe that represents the actual dynamic behavior of the complete run of the nonseismic Category I system. The length considered is classified as seismic Category II and extends to the interface anchor or rigid support as described below.

The seismic Category II portion of the line, up to the interface anchor or interface rigid support (last seismic support), is analyzed according to Equation 9 of ASME Code, Section III, Class 3, with a stress limit equal to the smaller of 4.5 S_h and 3.0 S_y. In either case, the nonseismic piping is isolated from the seismic Category I piping by anchors or seismic supports. The anchor or seismic Category II supports are designed for loads from the nonseismic piping. This includes three plastic moment components (M_{p1}, M_{p2}, or M_{p3}) in each of three local coordinate directions. The responses to the three moments are evaluated independently. The seismic Category II portion of the line is analyzed by the response spectrum or equivalent static load method for safe shutdown earthquake.

Single Interface Anchor

The seismic Category II piping may be terminated at a single interface anchor (six-way). This anchor and the supports on the seismic Category II piping are evaluated for safe shutdown earthquake loadings using the rules of ASME III Subsection NF. If the anchor is an equipment nozzle, then the equipment load path through the equipment supports are evaluated to the same acceptance criteria as seismic Category I equipment.

Anchor Followed by a Series of Seismic Supports

The seismic Category II piping may be terminated at the last seismic support which follows a six-way anchor on the seismic Category II piping. This last seismic support and the supports on the seismic Category II piping are evaluated for safe shutdown earthquake loadings using the rules of ASME III Subsection NF. From the anchor to the last seismic support, the response to the

plastic moments (M_{p1}, M_{p2}, or M_{p3}) is combined with the responses to seismic anchor motions and equivalent static seismic inertia of the piping system by the absolute sum method. The responses to these moments are evaluated independently. The support and anchor loads due to the plastic moments (M_{p1}, M_{p2}, or M_{p3}) of the seismically analyzed and supported section can be reduced if the elbow/bend resultant moments have exceeded the plastic limit moments of the elbow/bend. The value of the reduction factor RF is as follows:

RF = *Multiplier used to reduce the interface anchor and support loads*

RF = *< l, (if RF > l, no reduction is applicable)*

RF = M_L/M_a

M_a = *Resultant moment at elbow/bend. Use maximum value if several elbows/bends are within seismically supported region.*

M_L = $0.8h^{0.6} D^2 t\,Sy$ *for* $h < 1.45$

M_L = $D^2 t\,Sy$ *for* $h > 1.45$

h = *Flexibility characteristic of elbow/bend*

D = *Outside diameter of elbow/bend*

t = *Thickness of elbow/bend*

R = *Bend radius of elbow/bend*

Rigid Region

The seismic Category II piping may be terminated at the last seismic support of a rigidly supported region of the piping system. The rigid region is typically defined as either four bi-lateral supports around an elbow or six bilateral supports around a tee. The structural behavior of the rigid region is similar to that of a six-way anchor. The frequency of the piping system in the rigid region is greater than or equal to 33 hertz. This last seismic support in the rigid region and the supports on the seismic Category II piping are evaluated for safe shutdown earthquake loadings using the rules of ASME III Subsection NF.

3.7.3.13.4.3 Nonseismic Piping

Nonseismic piping within the impact evaluation zone is seismically supported, thereby ensuring that the pipe segment identified as a source will not fall or adversely impact the sensitive target (Table 3.7-2). This situation is shown in Figure 3.7.3-2, and the seismic supported piping criteria described below:

- *Supports within the impact evaluation zone, plus one transverse support in each transverse direction beyond the impact evaluation zone, are classified as seismic Category II and are*

evaluated for the safe shutdown earthquake loading using the rules of ASME III, Subsection NF.

- *Piping within the impact evaluation zone plus one transverse support in each transverse direction are evaluated to Equation 9 of ASME Code, Section III, Class 3, with a stress limit equal to the smaller of 4.5* S_h *and 3.0* S_y*. Outside the impact evaluation zone, the nonseismic piping meets ASME/ANSI B31.1 requirements.*

- *The nonseismic piping and seismic Category II supports are designed for loads from the nonseismic piping beyond the impact evaluation zone. This includes three plastic moment components (*M_{p1}*,* M_{p2}*, or* M_{p3}*) in each of three local coordinate directions applied at the first and last seismic Category II support. The responses to the three moments are evaluated independently. The response from the moments applied at the first seismic Category II support is combined with the response from the moments applied at the last seismic Category II support and with the responses to seismic anchor motions and equivalent static seismic inertia of the piping system by the absolute sum method. The support and anchor loads due to the plastic moments (*M_{p1}*,* M_{p2}*, or* M_{p3}*) of the seismically analyzed and supported section can be reduced if the elbow/bend resultant moments have exceeded the plastic limit moments of the elbow/bend. The value of the reduction factor RF is the same as the value for connected seismic Category II piping described above.*

- *The piping segment identified as the source has at least one effective axial support.*

- *Adequate free space between a source and a target is checked adding absolutely the piping safe shutdown earthquake deflections (defined following seismic Category II piping analysis methodology) and the safe shutdown earthquake target deflection. Also included are the displacements associated with the appropriate load cases.*

- *When the anchor is an equipment nozzle, the equipment is supported as seismic Category II as described in subsection 3.7.3.13.3.*]*

3.7.3.14 Seismic Analyses for Reactor Internals

See subsection 3.9.2 for the dynamic analyses of reactor internals.

3.7.3.15 Analysis Procedure for Damping

Damping values used in the seismic analyses of subsystems are presented in subsection 3.7.1.3. Safe shutdown earthquake damping values used for different types of analysis are provided in Table 3.7.1-1. For subsystems that are composed of different material types, the composite modal damping approach with the weighted stiffness method is used to determine the composite modal damping value. Alternately, the minimum damping value may be used for these systems. [*Composite modal damping for coupled building and piping systems is used for piping systems that are coupled to the primary coolant loop system and the interior concrete building. Composite modal damping is used for piping systems that are coupled to flexible equipment or flexible valves. Piping systems analyzed by the uniform envelope response spectra method with rigid*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

valves can be evaluated with 5 percent damping. Five percent damping is not used in piping systems that are susceptible to stress corrosion cracking.]*

For the time history dynamic analysis and independent support motion response spectra analysis of piping systems, 4 percent, 3 percent, and 2 percent damping values are used as described in Table 3.7.1-1.

When piping systems and nonsimple module steel frames (simple frames are described in subsection 3.7.3.8.3) are in a single coupled model, composite damping, as described in subsection 3.7.1.3 is used.

3.7.3.16 Analysis of Seismic Category I Tanks

This subsection describes the seismic analyses for the large, atmospheric seismic Category I pools and tanks. These are reinforced concrete structures with stainless steel liners or with structural modules, as discussed in subsections 3.8.3 and 3.8.4. They include the spent fuel pit in the auxiliary building, the in-containment refueling water storage tank, and the passive containment cooling water tank incorporated into the shield building roof. There are no other seismic Category I tanks.

The seismic analyses of the tank consider the impulsive and convective forces of the water as well as the flexibility of the walls. For the spent fuel pit, cask loading pit, cask washdown pit and fuel transfer canal, the impulsive loads are calculated by considering a portion of the water mass responding with the concrete walls. The impulsive forces are calculated by conventional methods for rigid tanks. The passive containment cooling water tank is analyzed using methods described in Reference 15 for toroidal tanks. It is also analyzed by finite element methods. The in-containment refueling water storage tank is irregular in plan and is analyzed by finite element methods.

3.7.3.17 Time History Analysis of Piping Systems

[*The time history dynamic analysis is an alternate seismic analysis method for response spectrum analysis when time history seismic input is used. This method is also used for dynamic analyses of piping systems subjected to time history hydraulic transient loadings or forcing functions induced by postulated pipe breaks. The modal superposition method is used to solve the equations of motion. The computer programs used are GAPPIPE, PIPESTRESS, ANSYS, and WECAN.*

The modal superposition method is based on the equations of motion which can be decoupled as long as the piping system is within its elastic limit. The modal responses are obtained from integrating the decoupled equations. The total responses are obtained by the algebraic sum of the individual responses of the individual modes at each time step. The cutoff frequency is selected based on the frequency content of the input forcing function and the highest significant frequency of the piping system. The integration time step is no larger than 10 percent of the period of the cutoff frequency.

For dynamic analysis, including seismic analysis at a hard rock site, three separate analyses are performed for each loading case to account for uncertainties. The three analyses correspond to three different time scales: normal time, time expanded by 15 percent, and time compressed by

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

15 percent. For time history analysis of piping system models that include a dynamic model of the supporting concrete building either the building stiffness is varied by + and - 30 percent, or the time scale is shifted by + and - 15 percent. Alternately, when uniform enveloping time history analysis is performed, modeling uncertainties are accounted for by the spreading that is included in the broadened response spectra.

For time history analysis using the PIPESTRESS program, the response from the high frequency modes above the cutoff frequency is calculated based on the static response to the left-out-forces. This response is combined with the response from the low frequency modes by algebraic sum at each time step. Composite modal damping is used with PIPESTRESS program. The damping of the individual components is as listed in Table 3.7.1-1.

Alternately, for time history analysis using the PIPESTRESS, GAPPIPE, ANSYS, or WECAN programs, the number of modes used in the modal analysis is chosen so that the results of the dynamic analysis based on the chosen number of modes are within 10 percent of the results of the dynamic analysis based on the next higher number of modes used. The number of modes analyzed is selected to account for the principal vibration modes of the piping system. The modes are combined by algebraic sum. Composite modal damping is used with the ANSYS or WECAN programs. The damping of the individual components is as listed in Table 3.7.1-1.]*

3.7.4 Seismic Instrumentation

3.7.4.1 Comparison with Regulatory Guide 1.12

Compliance with Regulatory Guide 1.12 is discussed in this section and in subsection 1.9.1.

3.7.4.1.1 Safety Design Basis

The seismic instrumentation serves no safety-related function and therefore has no nuclear safety design basis.

3.7.4.1.2 Power Generation Design Basis

The seismic instrumentation is designed to provide the following:

- Collection of seismic data in digital format
- Analysis of seismic data after a seismic event
- Operator notification that a seismic event exceeding a preset value has occurred
- Operator notification (after analysis of data) that a predetermined cumulative absolute velocity value has been exceeded

3.7.4.2 Location and Description of Instrumentation

The following instrumentation and associated equipment are used to measure plant response to earthquake motion.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Four triaxial acceleration sensor units, located as stated in subsection 3.7.4.2.1, are connected to a time-history analyzer. The time-history analyzer recording and playback system is located in a panel in the nuclear island in a room near the main control room. Seismic event data from these sensors are recorded on a solid-state digital recording system at 200 samples per second per data channel.

This solid-state recording and analysis system has internal batteries and a charger to prevent the loss of data during a power outage, and to allow data collection and analysis in a seismic event during which the power fails. Normally 120 volt alternating current power is supplied from the non-Class 1E dc and uninterruptible power supply system. The system uses triaxial acceleration sensor input signals to initiate the time-history analyzer recording and main control room alarms. The system initiation value is adjustable from 0.002g to 0.02g.

The time-history analyzer starts recording triaxial acceleration data from each of the triaxial acceleration sensors after the initiation value has been exceeded. Pre-event recording time is adjustable from 1.2 to 15.0 seconds, and will be set to record at least 3 seconds of pre-event signal. Post-event run time is adjustable from 10 to 90 seconds. A minimum of 25 minutes of continuous recording is provided. Each recording channel has an associated timing mark record with 2 marks per second, with an accuracy of about 0.02 percent.

The instrumentation components are qualified to IEEE 344-1987 (Reference 16).

The sensor installation anchors are rigid so that the vibratory transmissibility over the design spectra frequency range is essentially unity.

3.7.4.2.1 Triaxial Acceleration Sensors

Each sensor unit contains three accelerometers mounted in a mutually orthogonal array mounted with one horizontal axis parallel to the major axis assumed in the seismic analysis. The triaxial acceleration sensors have a dynamic range of 1000 to 1 (0.001 to 1.0g) and a frequency range of 0.2 to 50 hertz.

One sensor unit will be located in the free field. Because this location is site-specific, the planned location will be determined by the Combined License applicant. The AP1000 seismic monitoring system will provide for signal input from the free field sensor.

A second sensor unit is located on the nuclear island basemat in the spare battery charger room at elevation 66′-6″ near column lines 9 and L.

A third sensor unit is located on the shield building structure at elevation 266′ near column lines 4-1 and K.

The fourth sensor unit is located on the containment internal structure on the east wall of the east steam generator compartment just above the operating floor at elevation 138′ close to column lines 6 and K.

Seismic instrumentation is not located on equipment, piping, or supports since experience has shown that data obtained at these locations are obscured by vibratory motion associated with normal plant operation.

3.7.4.2.2 Time-History Analyzer

The time-history analyzer receives input from the triaxial acceleration sensors and, when activated as described in subsection 3.7.4.3, begins recording the triaxial data from each triaxial acceleration sensor and initiates audio and visual alarms in the main control room.

This recorded data will be used to evaluate the seismic acceleration of the structure on which the triaxial acceleration sensors are mounted.

The time-history analyzer is a multichannel, digital recording system with the capability to automatically download the recorded acceleration data to a dedicated computer for data storage, playback, and analysis after a seismic event.

The time-history analyzer can compute cumulative absolute velocity (CAV) and the 5 percent of critical damping response spectrum for frequencies between 1 and 10 Hz. The operator may select the analysis of either CAV or the response spectrum. Analysis results are printed out on a dedicated graphics printer that is part of the system and is located in the same panel as the time-history analyzer.

3.7.4.3 Control Room Operator Notification

The time-history analyzer provides for initiation of audible and visual alarms in the main control room when predetermined seismic acceleration values sensed by any of the triaxial acceleration sensors are exceeded and when the system is activated to record a seismic event. In addition to alarming when the system is activated, the analyzer portion of the system will provide a second alarm if the predetermined cumulative absolute velocity value has been exceeded by any of the sensors. Alarms are annunciated in the main control room.

3.7.4.4 Comparison of Measured and Predicted Responses

The recorded seismic data is used by the combined license holder operations and engineering departments to evaluate the effects of the earthquake on the plant structures and equipment.

The criterion for initiating a plant shutdown following a seismic event will be exceedance of a specified response spectrum limit or a cumulative absolute velocity limit. The seismic instrumentation system is capable of computing the cumulative absolute velocity as described in EPRI Report NP-5930 (Reference 1) and EPRI Report TR-100082 (Reference 17).

3.7.4.5 Tests and Inspections

Periodic testing of the seismic instrumentation system is accomplished by the functional test feature included in the software of the time-history recording accelerograph. The system is modular and is capable of single-channel testing or single channel maintenance without disabling the remainder of the system.

3.7.5 Combined License Information

3.7.5.1 Seismic Analysis of Dams

Combined License applicants referencing the AP1000 certified design will evaluate dams whose failure could affect the site interface flood level specified in subsection 2.4.1.2. The evaluation of the safety of existing and new dams will use the site-specific safe shutdown earthquake.

3.7.5.2 Post-Earthquake Procedures

Combined License applicants referencing the AP1000 certified design will prepare site-specific procedures for activities following an earthquake. These procedures will be used to accurately determine both the response spectrum and the cumulative absolute velocity of the recorded earthquake ground motion from the seismic instrumentation system. The procedures and the data from the seismic instrumentation system will provide sufficient information to guide the operator on a timely basis to determine if the level of earthquake ground motion requiring shutdown has been exceeded. The procedures will follow the guidance of EPRI Reports NP-5930 (Reference 1), TR-100082 (Reference 17), and NP-6695 (Reference 18), as modified by the NRC staff (Reference 32).

3.7.5.3 Seismic Interaction Review

The seismic interaction review will be updated by the Combined License applicant. This review is performed in parallel with the seismic margin evaluation. The review is based on as-procured data, as well as the as-constructed condition.

3.7.5.4 Reconciliation of Seismic Analyses of Nuclear Island Structures

The Combined License applicant will reconcile the seismic analyses described in subsection 3.7.2 for detail design changes at rock sites such as those due to as-procured equipment information. Deviations are acceptable based on an evaluation consistent with the methods and procedure of Section 3.7 provided the amplitude of the seismic floor response spectra including the effect due to these deviations, do not exceed the design basis floor response spectra by more than 10 percent.

3.7.5.5 Free Field Acceleration Sensor

The Combined License applicant will determine the location for the free-field acceleration sensor as described in subsection 3.7.4.2.1.

3.7.6 References

1. EPRI Report NP-5930, "A Criterion for Determining Exceedance of the Operating Basis Earthquake," July 1988.

2. Uniform Building Code, 1997.

3. ASCE Standard 4-98, "Seismic Analysis of Safety-Related Nuclear Structures and Commentary," American Society of Civil Engineers, September 1986.

4. ASME B&PV Code, Code Case N-411.

5. FEMA 356, "Prestandard and Commentary for the Seismic Rehabilitation of Buildings," Federal Emergency Management Agency, November 2000.

6. Deleted

7. Deleted

8. Deleted

9. Deleted

10. Hyde, S. J., J. M. Pandya, and K. M. Vashi, "Seismic Analysis of Auxiliary Mechanical Equipment in Nuclear Plants," Dynamic and Seismic Analysis of Systems and Components, ASME-PVP-65, American Society of Mechanical Engineers, Orlando, Florida, 1982.

11. Lin, C. W., and T. C. Esselman, "Equivalent Static Coefficients for Simplified Seismic Analysis of Piping Systems," SMIRT Conference 1983, Paper K12/9.

12. M. S. Yang, J. S. M. Leung, and Y. K. Tang, "Analysis of Piping Systems with Gapped Supports Using the Response Spectrum Method." Presented at the 1989 ASME Pressure Vessels and Piping Conference at Honolulu, July 23-27, 1989.

13. "Impact Response of Piping Systems with Gaps," P. H. Anderson and H. Loey, ASME Seismic Engineering, 1989, Volume 182.

14. "Independent Support Motion (ISM) Method of Modal Spectra Seismic Analysis," December 1989; by Task Group on Independent Support Motion as Part of the PVRC Technical Committee on Piping Systems Under the Guidance of the Steering Committee.

15. J. S. Meserole, A. Fortini, "Slosh Dynamics in a Toroidal Tank," Journal Spacecraft Vol. 24, Number 6, November-December 1987.

16. IEEE 344-1987, "Recommended Practices for Seismic Qualification of 1E Equipment for Nuclear Power Generating Stations."

17. EPRI Report TR-100082, "Standardization of the Cumulative Absolute Velocity," December 1991.

18. EPRI Report NP-6695, "Guidelines for Nuclear Plant Response to an Earthquake," December 1989.

19. "Cable Tray and Conduit Raceway Seismic Test Program, Release 4," Report 1053-21.1-4, ANCO Engineers, Inc., December 15, 1978.

20. Deleted

21. Deleted

22. WCAP 7921AR, "Damping Values of Nuclear Power Plant Components," May 1974.

23. McGuire, R. K., G. R. Toro, and W. J. Silva, "Engineering Model of Earthquake Ground Motion for Eastern North America," Technical Report NP-6074, Electric Power Research Institute, 1988.

24. Boore, D. M. and G. M. Atkinson, "Stochastic prediction of ground motion and spectral response at hard-rock sites in eastern North America," Bull. Seism. Soc. Am., 77:2, pages 440-467.

25. Nuttli, O. W., Letter dated September 19, 1986 to J. B. Savy, Reproduced in: D. Bernreuter, J. Savy, R. Mensing, J. Chen, and B. Davis, "Seismic Hazard Characterization of 69 Nuclear Plant Sites East of the Rocky Mountains: Questionnaires," U.S. Nuclear Regulatory Commission, Technical Report NUREG/CR-5250, UCID-21517, 7, Prepared by Lawrence Livermore National Laboratory.

26. Trifunac, M. and V. W. Lee, "Preliminary Empirical Model for Scaling Pseudo Velocity Spectra of Strong Earthquake Accelerations in Terms of Magnitude, Distance, Site Intensity and Recording Site Conditions," Report No. CE 85-04, University of Southern California, Department of Civil Engineering, 1985.

27. Bernreuter, D., J. Savy, R. Mensing, J. Chen, and B. Davis, "Seismic Hazard Characterization of 69 Nuclear Plant Sites East of the Rocky Mountains: Questionnaires," U.S. Nuclear Regulatory Commission, Technical Report NUREG/CR-5250, UCID-21517, Lawrence Livermore National Laboratory, 1989.

28. McGuire, R. K., G. R. Toro, J. P Jacobson, T. F. O'Hara, and W. J. Silva, "Probabilistic Seismic Hazard Evaluations at Nuclear Plant Sites in the Central and Eastern United States: Resolution of the Charleston Earthquake Issue," Technical Report NP-6395-D, Electric Power Research Institute, 1989.

29. Philippacoupoulos, A. J., "Recommendations for Resolution of Public Comments on USI A-40, Seismic Design Criteria," Brookhaven National Laboratory Report BNL-NUREG-52191, prepared for the U.S. Nuclear Regulatory Commission, and published as NUREG/CR-5347, 1989.

30. C. Chen, "Definition of Statistically Independent Time Histories," Journal of the Structural Division, ASCE, February 1975.

31. WCAP-9903, "Justification of the Westinghouse Equivalent Static Analysis Method for Seismic Qualification of Nuclear Power Plant Auxiliary Mechanical Equipment," August 1980.

32. Letter from James T. Wiggins to John J. Taylor, September 13, 1993.

33. Deleted

34. "Seismic Provisions for Structural Steel Buildings," American Institute of Steel Construction, April 1997 including Supplement No. 2, November 2000.

35. "Minimum Design Loads for Buildings and Other Structures," American Society of Civil Engineers, ASCE 7-98.

36. ANSYS Engineering Analysis Users Manual, Releases up to and including ANSYS 5.7, ANSYS Inc.

Table 3.7.1-1

SAFE SHUTDOWN EARTHQUAKE DAMPING VALUES

	Percent
Welded and friction-bolted steel structures and equipment	4
Bearing bolted structures and equipment	7
Prestressed concrete structures	5
Reinforced concrete structures	7
Concrete filled steel plate structures	5
[*Piping (for uniform envelope response spectra analysis)*	*5*
Piping (alternative for time history analysis and independent support motion response spectra analysis)	
Less than or equal to 12-inch diameter	*2*
Greater than 12-inch diameter	*3*
Primary coolant loop	*4*]*
Fuel assemblies	20
Control rod drive mechanisms	5
Full cable trays and related supports	10[1]
Empty cable trays and related supports	7
Conduits and related supports	7
HVAC ductwork	7
HVAC welded ductwork	4
Cabinets and panels for electrical equipment	5
Equipment such as welded instrument racks and tanks	3

Note:
1. Cable tray systems similar to those tested in Reference 19 may use the damping values given in Figure 3.7.1-13.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.7.1-2

EMBEDMENT DEPTH AND RELATED DIMENSIONS OF CATEGORY I STRUCTURES

Structure	Foundation Embedment Depth (ft)	Least Foundation Width (ft)	Structure Height (ft)
Shield Building	See Note	See Note	273.25
Steel Containment Vessel	See Note	See Note	215.33
Auxiliary Building	See Note	See Note	119.50

Note:
1. The seismic Category I structures are founded on a common basemat embedded 39.5 feet, [*with dimensions shown in Figure 3.7.1-14.*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.7.1-3

**AP1000 DESIGN RESPONSE SPECTRA
AMPLIFICATION FACTORS FOR CONTROL POINTS**

HORIZONTAL					
Percent of Critical Damping	**Acceleration(1)**				**Displacement(1)**
	A (33 cps)	**B' (25 cps)(2)**	**B (9 cps)**	**C (2.5 cps)**	**D (0.25 cps)**
2.0	1.0	1.70	3.54	4.25	2.50
3.0	1.0	1.66	3.13	3.76	2.34
4.0	1.0	1.63	2.84	3.41	2.19
5.0	1.0	1.60	2.61	3.13	2.05
7.0	1.0	1.55	2.27	2.72	1.88
VERTICAL					
Percent of Critical Damping	**Acceleration(1)**				**Displacement(1)**
	A (33 cps)	**B' (25 cps)(2)**	**B (9 cps)**	**C (3.5 cps)**	**D (0.25 cps)**
2.0	1.0	1.70	3.54	4.05	1.67
3.0	1.0	1.66	3.13	3.58	1.56
4.0	1.0	1.63	2.84	3.25	1.46
5.0	1.0	1.60	2.61	2.98	1.37
7.0	1.0	1.55	2.27	2.59	1.25

Notes:

1. Maximum ground displacement is taken proportional to maximum ground acceleration, and is 36 inches for ground acceleration of 1.0 gravity.
2. The 5 percent damping amplification factor for control point B' is derived per discussion in subsection 3.7.1.1. This 5 percent damping amplification factor equals 1.3 times the RG 1.60 response spectra at 25 hertz. The amplification factors at control point B' for other damping values are determined by increasing the RG 1.60 response spectra at 25 hertz by 30 percent.

Table 3.7.2-1

COUPLED SHIELD AND AUXILIARY BUILDINGS LUMPED-MASS STICK MODEL MODAL PROPERTIES

Mode	Frequency	Effective Mass		
		X Direction	Y Direction	Z Direction
1	0.136	2.074	1.201	0.000
2	0.136	1.429	1.789	0.000
3	0.136	117.647	4.908	0.000
4	0.136	4.871	118.308	0.000
5	2.714	0.264	1781.020	0.064
6	2.977	1583.970	0.543	0.753
7	5.175	1.011	1.191	952.776
8	5.897	236.603	46.526	0.003
9	6.075	3.133	944.559	0.657
10	6.321	569.763	0.298	0.562
11	7.933	4.737	837.416	1.838
12	8.482	1066.990	1.634	1.203
13	11.362	162.895	0.455	132.088
14	12.285	0.222	12.975	14.900
15	12.672	28.018	3.761	1965.430
16	13.345	1.554	193.490	4.400
17	14.703	91.688	0.284	16.711
18	15.997	0.810	2.330	65.091
19	17.995	22.757	102.600	15.333
20	18.582	152.397	21.007	17.522
21	20.172	0.045	29.501	0.148
Sum of Effective Masses		4761.4	4759.73	4355.34

Notes:
1. Fixed at elevation 60.5′.
2. The first four modes are principally water sloshing in the passive containment system tank.
3. Concrete modulus of elasticity equals 415,200 ksf.

Table 3.7.2-2 (Sheet 1 of 2)

STEEL CONTAINMENT VESSEL LUMPED-MASS STICK MODEL (WITHOUT POLAR CRANE) MODAL PROPERTIES

Mode	Frequency	Effective Mass		
		X Direction	Y Direction	Z Direction
1	6.309	2.380	159.153	0.005
2	6.311	159.290	2.382	0.000
3	12.942	0.018	0.000	0.000
4	16.970	0.000	0.006	171.030
5	18.960	0.102	40.263	0.002
6	18.970	40.161	0.102	0.000
7	28.201	0.000	0.000	28.073
8	31.898	0.054	2.636	0.000
9	31.999	2.789	0.057	0.000
10	37.990	0.909	0.007	0.000
11	38.634	0.022	4.846	0.009
12	38.877	3.758	0.014	0.000
13	47.387	0.000	0.000	5.066
14	54.039	4.649	0.633	0.000
15	54.065	0.624	4.693	0.002
16	60.628	0.002	0.042	3.389
17	62.734	0.147	0.001	0.018
18	63.180	0.000	0.050	7.069
19	63.613	0.002	0.001	0.003
20	65.994	0.022	0.659	0.041
Sum of Effective Masses		214.929	215.545	214.706

Notes:
1. Fixed at Elevation 100′.
2. The total mass of the containment vessel is 225.697 kip-sec^2/ft.

Table 3.7.2-2 (Sheet 2 of 2)

**STEEL CONTAINMENT
VESSEL LUMPED-MASS STICK MODEL (WITH POLAR CRANE)
MODAL PROPERTIES**

Mode	Frequency	Effective Mass		
		X Direction	Y Direction	Z Direction
1	3.619	0.000	41.959	0.000
2	5.387	175.274	0.000	0.175
3	6.192	0.000	148.385	0.005
4	6.415	3.321	0.000	24.074
5	9.422	0.002	1.017	0.000
6	9.674	10.510	0.000	0.532
7	12.811	0.015	0.001	0.000
8	15.757	0.004	0.320	0.010
9	16.367	3.103	0.003	159.153
10	17.495	28.537	0.001	19.546
11	18.944	0.000	40.053	0.001
12	21.043	10.724	0.000	0.426
13	22.102	0.000	0.005	0.000
14	27.340	0.054	0.000	18.661
15	30.387	2.978	0.001	1.559
16	31.577	0.002	3.526	0.004
17	35.033	0.194	0.006	3.895
18	35.535	0.211	0.027	0.399
19	35.646	0.000	1.451	0.019
20	37.599	0.325	0.426	0.007
Sum of Effective Masses		235.254	237.181	228.465

Notes:
1. Fixed at Elevation 100′.
2. The total mass of the containment vessel with the polar crane is 255.85 kip-sec^2/ft.

Table 3.7.2-3 (Sheet 1 of 2)

**CONTAINMENT INTERNAL STRUCTURES
LUMPED-MASS STICK MODEL
MODAL PROPERTIES**

Mode	Frequency	Effective Mass		
		X Direction	Y Direction	Z Direction
1	10.534	5.953	526.669	0.722
2	11.344	640.045	1.676	0.180
3	12.495	60.666	77.489	0.312
4	15.608	33.584	223.472	0.026
5	16.137	180.804	3.625	0.025
6	19.767	211.303	0.912	0.438
7	23.852	13.488	824.587	2.413
8	24.662	39.764	15.418	55.875
9	25.077	795.172	38.124	1.359
10	25.756	0.149	267.021	1.436
11	26.130	53.676	37.209	48.810
12	28.773	0.233	2.070	6.204
13	30.686	0.005	8.188	0.148
14	32.525	0.296	0.048	2.359
15	36.026	34.644	4.614	990.200
16	37.532	13.602	0.027	178.257
17	40.928	1.373	62.955	0.957
18	41.666	0.740	98.499	12.148
19	42.077	0.312	0.188	2.904
20	42.749	114.401	0.367	222.112
21	44.680	0.224	16.494	27.027
Sum of Effective Masses		3022.9	3022.9	3022.8

Notes:
1. Fixed at Elevation 60.50′.
2. The total mass of the containment internal structure is 3242.1 kip-sec^2/ft.
3. Concrete modulus of elasticity equals 415,200 ksf.

Table 3.7.2-3 (Sheet 2 of 2)

**RCL LUMPED-MASS STICK MODEL
MODAL PROPERTIES**

Mode	Frequency	Effective Mass		
		X Direction	Y Direction	Z Direction
1	4.211	0.000	0.000	0.001
2	4.216	45.174	0.112	0.000
3	8.110	15.825	73.633	0.000
4	8.477	0.000	0.000	1.181
5	8.627	18.084	3.670	0.000
6	8.671	0.000	0.000	10.486
7	8.701	15.028	83.412	0.000
8	9.260	0.001	13.517	0.000
9	9.279	0.000	0.000	111.275
10	9.750	0.000	0.000	5.115
11	9.830	0.007	0.627	0.000
12	10.365	0.000	0.000	0.968
13	10.799	0.000	0.000	0.001
14	10.903	0.491	0.004	0.000
15	11.898	19.209	1.293	0.000
16	11.913	13.286	1.888	0.000
17	13.414	22.697	0.010	0.000
18	13.459	0.000	0.000	3.165
19	13.465	1.011	0.784	0.000
20	15.411	0.606	5.228	0.000
21	16.197	0.000	0.000	0.009
22	16.250	30.402	0.101	0.000
23	21.731	2.133	0.000	0.000
24	22.101	0.006	1.518	0.000
25	28.236	0.000	0.000	39.954
26	28.258	0.002	0.384	0.000
27	29.292	0.000	0.000	0.501
28	29.850	0.925	0.206	0.000
29	30.416	0.000	0.000	0.156
30	31.012	2.248	0.000	0.000
Sum of Effective Masses		187.132	186.387	172.811

Notes:
1. Fixed at building end of RCL supports.
2. The total mass of the RCL is 187.84 kip-sec^2/ft.

Table 3.7.2-4 (Sheet 1 of 5)

NUCLEAR ISLAND COMBINED LUMPED-MASS STICK MODEL MODAL PROPERTIES

Mode	Frequency	Effective Mass		
		X Direction	Y Direction	Z Direction
1	0.136	0.58	2.89	0.00
2	0.136	3.23	0.50	0.00
3	0.136	113.64	8.52	0.00
4	0.136	8.50	114.14	0.00
5	2.939	1.63	1546.35	0.36
6	3.135	1454.47	1.81	0.62
7	3.608	0.00	42.57	0.00
8	4.097	66.91	0.04	0.00
9	4.151	9.42	0.28	0.00
10	4.662	0.05	88.66	0.09
11	5.203	2.38	0.79	902.84
12	5.242	272.03	0.00	0.64
13	5.968	0.00	397.56	0.25
14	6.357	267.68	4.01	0.06
15	6.408	2.71	0.11	25.04
16	6.493	12.76	424.32	0.98
17	6.567	280.81	11.60	1.11
18	7.574	0.53	184.51	0.56
19	8.063	58.81	118.91	0.00
20	8.455	0.03	0.02	0.44
21	8.585	165.80	96.16	0.13
22	9.204	1.11	114.86	0.14
23	9.233	0.20	114.67	130.95
24	9.296	14.59	992.82	11.72
25	9.383	15.66	60.53	0.17
26	9.487	932.21	10.48	1.58
27	9.729	513.21	0.82	0.10
28	9.734	15.13	0.39	4.25
29	9.829	0.18	0.03	0.00
30	10.342	0.00	0.07	0.70
31	10.800	0.03	0.07	0.00
32	10.905	0.55	0.02	0.00
33	11.061	3.58	57.22	0.03
34	11.766	276.26	3.82	8.15
35	11.879	9.60	8.76	0.36
36	11.954	6.92	0.97	0.29
37	12.122	62.99	20.60	71.83
38	12.284	130.47	11.92	187.46
39	12.799	29.31	24.49	16.46
40	12.932	8.01	3.32	88.51
41	13.412	22.38	0.39	82.18

Table 3.7.2-4 (Sheet 2 of 5)

**NUCLEAR ISLAND COMBINED LUMPED-MASS STICK MODEL
MODAL PROPERTIES**

Mode	Frequency	Effective Mass		
		X Direction	Y Direction	Z Direction
42	13.456	0.44	0.16	24.00
43	13.478	1.60	1.97	7.14
44	13.535	59.70	7.47	1481.71
45	14.334	4.53	556.06	0.42
46	15.191	222.77	1.66	8.47
47	15.353	0.23	24.60	0.85
48	15.478	28.31	9.92	0.60
49	15.715	20.82	1.82	5.47
50	15.757	11.33	0.75	5.28
51	16.220	2.18	0.26	179.18
52	16.248	0.80	0.01	20.28
53	16.567	1.45	2.58	60.17
54	17.351	64.11	0.04	25.15
55	17.537	1.08	12.86	2.44
56	18.617	0.55	194.82	1.82
57	18.807	249.15	0.00	0.16
58	19.871	16.31	210.08	20.20
59	20.240	219.50	36.03	32.97
60	21.029	0.03	1.09	12.68
61	21.715	0.61	98.22	19.27
62	21.733	2.33	63.51	3.58
63	22.093	0.22	1.07	0.68
64	22.119	0.05	1.29	10.19
65	22.467	5.68	10.92	65.94
66	23.043	192.52	59.73	124.22
67	23.526	1.24	36.43	25.52
68	23.647	15.64	69.39	210.40
69	24.827	82.64	189.55	13.51
70	25.060	26.60	1.51	19.16
71	25.650	130.02	21.27	36.57
72	25.949	7.42	16.18	193.64
73	26.071	6.64	12.93	129.80
74	27.131	0.52	176.92	159.62
75	27.276	9.43	115.43	2.62
76	27.482	309.97	16.21	8.68
77	28.040	0.08	2.93	58.18
78	28.248	1.29	1.96	0.00
79	28.503	3.22	29.06	0.03
80	28.936	2.29	3.73	2.71
81	29.387	0.20	2.29	0.54
82	29.648	0.09	5.34	14.92

Table 3.7.2-4 (Sheet 3 of 5)

NUCLEAR ISLAND COMBINED LUMPED-MASS STICK MODEL MODAL PROPERTIES

Mode	Frequency	Effective Mass		
		X Direction	Y Direction	Z Direction
83	29.924	6.44	2.23	0.42
84	30.387	0.01	0.53	0.87
85	30.489	15.11	0.08	15.50
86	30.756	0.08	4.38	52.08
87	31.017	0.06	3.73	0.60
88	31.072	2.98	1.65	0.02
89	31.318	2.00	5.16	2.90
90	31.952	0.26	103.00	3.09
91	32.513	0.92	0.88	115.58
92	32.875	0.74	0.10	106.33
93	33.938	172.70	27.66	2.54
94	34.613	31.79	6.65	2.26
95	34.717	9.17	26.09	0.00
96	34.968	14.57	0.75	26.66
97	35.491	5.02	0.03	7.69
98	35.538	1.17	0.02	25.84
99	36.109	0.04	3.45	6.94
100	36.319	15.08	0.40	60.36
101	36.768	0.02	7.93	677.47
102	36.946	0.01	0.00	0.26
103	37.262	0.20	0.01	0.00
104	37.724	1.78	0.74	27.87
105	38.418	2.54	4.14	23.10
106	38.776	0.87	0.07	103.82
107	38.867	0.32	11.46	59.96
108	39.025	0.29	17.61	10.86
109	39.154	20.69	10.35	0.69
110	40.445	11.75	0.06	60.29
111	41.087	1.75	0.54	0.88
112	41.537	0.18	1.67	0.32
113	41.747	0.07	0.01	1.01
114	42.109	0.00	0.09	0.19
115	43.597	0.53	0.82	1.50
116	44.079	0.72	100.80	1.36
117	45.443	20.85	6.49	5.89
118	45.694	15.83	2.00	40.29
119	45.969	0.10	3.75	3.54
120	46.270	0.34	27.12	17.94
121	46.888	50.93	1.59	30.51
122	47.160	5.51	0.44	0.29

Table 3.7.2-4 (Sheet 4 of 5)

NUCLEAR ISLAND COMBINED LUMPED-MASS STICK MODEL MODAL PROPERTIES

Mode	Frequency	Effective Mass		
		X Direction	Y Direction	Z Direction
123	47.252	4.65	2.43	1.15
124	47.256	4.24	0.15	2.71
125	47.935	40.00	0.45	47.27
126	48.479	1.95	0.00	0.02
127	48.590	3.02	0.48	1.83
128	49.083	0.00	0.00	0.01
129	49.401	11.79	3.13	0.68
130	49.718	0.07	0.01	0.00
131	50.063	0.01	0.00	0.00
132	50.396	0.65	7.59	36.37
133	50.420	0.08	0.28	1.17
134	50.806	1.10	24.53	9.08
135	51.005	0.14	2.84	2.33
136	51.249	34.93	31.14	1.34
137	51.388	2.09	5.24	0.08
138	52.360	22.20	7.25	9.37
139	52.528	9.78	9.08	2.45
140	53.285	79.98	0.71	0.00
141	53.390	0.88	0.11	0.20
142	53.401	0.00	0.00	0.00
143	53.581	0.00	0.00	0.07
144	53.694	2.41	216.74	79.71
145	53.860	0.06	7.33	0.29
146	54.045	0.05	0.02	0.25
147	54.433	76.46	21.59	68.78
148	54.799	41.08	22.26	58.60
149	54.801	4.51	1.86	4.81
150	55.289	43.61	0.03	11.69
151	55.404	0.01	0.77	0.01
152	55.409	0.02	0.88	0.30
153	55.631	39.14	71.60	36.34
154	56.605	0.00	1.09	2.01
155	57.504	1.39	1.06	2.95
156	57.662	12.85	7.31	0.14
157	59.246	3.54	1.21	156.72
158	60.734	4.90	0.83	10.81
159	60.844	0.70	0.36	0.89
160	61.186	3.24	0.06	4.22
161	61.507	0.33	0.25	17.29
162	62.272	0.23	0.01	2.50
163	62.328	1.64	0.16	0.65

Table 3.7.2-4 (Sheet 5 of 5)

NUCLEAR ISLAND COMBINED LUMPED-MASS STICK MODEL MODAL PROPERTIES

Mode	Frequency	Effective Mass		
		X Direction	Y Direction	Z Direction
164	62.654	0.01	0.02	0.27
165	63.293	0.97	0.05	74.72
166	63.331	0.00	0.06	0.30
167	63.392	0.02	3.68	15.22
168	63.699	0.00	0.00	0.00
169	63.769	0.00	0.00	0.01
170	64.155	0.00	0.00	0.00
171	64.259	1.25	0.06	1.19
172	64.402	0.24	0.07	5.71
173	64.974	0.01	0.00	0.00
174	65.286	0.01	0.01	3.55
175	65.397	0.00	0.00	0.01
176	65.571	1.11	0.48	126.45
177	66.282	0.01	0.06	0.14
178	66.832	0.65	2.03	16.87
179	67.094	0.03	39.95	0.96
180	68.398	0.00	0.43	55.25
181	70.398	0.00	0.00	0.05
182	72.034	0.21	1.30	0.47
183	72.596	0.18	0.00	0.12
184	73.376	4.22	0.01	2.23
185	73.455	20.29	0.03	12.49
186	74.055	0.00	0.00	0.00
187	75.250	11.02	4.74	12.86
188	75.499	0.01	0.01	0.00
189	77.128	1.15	3.92	36.69
190	77.326	0.00	0.05	0.13
191	77.666	0.05	0.11	0.71
192	78.357	0.00	0.00	0.00
193	78.386	0.05	0.02	0.14
194	79.051	5.59	1.32	4.27
195	80.271	0.71	0.03	0.24
196	82.234	0.64	0.04	0.61
197	82.255	0.10	0.01	0.10
198	82.799	0.01	0.06	2.14
199	83.262	0.01	0.77	5.45
200	83.8436	0.03	0.01	0.12
SUMMATIONS		7383.64	7362.66	6979.1
TOTAL MASS		8717.8	8717.8	8717.8

Note:
1. Fixed at Elevation 60.5′.

Table 3.7.2-5

MAXIMUM ABSOLUTE NODAL ACCELERATION (ZPA)
COUPLED AUXILIARY & SHIELD BUILDINGS

HARD ROCK SITE CONDITION

Elevation (ft)	Maximum Absolute Nodal Acceleration, ZPA (g)					
	N-S Direction		E-W Direction		Vertical Direction	
	Mass Center	Edge	Mass Center	Edge	Mass Center	Edge
333.13	1.46	1.47	1.51	1.61	1.01	1.50
295.23	1.12	1.14	1.10	1.15	1.00	1.46
265.00	0.91	0.92	0.97	1.05	0.71	1.11
242.50	0.81	0.82	0.89	0.99	0.69	1.05
220.00	0.71	0.72	0.80	0.89	0.65	0.92
200.00	0.71	0.80	0.77	0.82	0.59	0.79
179.56	0.76	0.80	0.78	0.83	0.52	0.71
164.51	0.73	0.75	0.75	0.83	0.48	0.65
153.98	0.70	0.70	0.73	0.80	0.44	0.61
134.87	0.60	0.61	0.63	0.73	0.41	0.81
116.50	0.50	0.51	0.50	0.56	0.37	0.69
99.00	0.39	0.41	0.40	0.42	0.34	0.50
81.50	0.33	0.34	0.33	0.34	0.31	0.35
66.50	0.30	0.30	0.30	0.30	0.30	0.30

Note:

1. The results at the edges are on the auxiliary building at and below the elevation 134.87′ and on the shield building above this elevation. This is the maximum value of the response at any of these edge nodes.

Table 3.7.2-6

MAXIMUM ABSOLUTE NODAL ACCELERATION (ZPA)
STEEL CONTAINMENT VESSEL

HARD ROCK SITE CONDITION

Elevation (ft)	Maximum Absolute Nodal Acceleration, ZPA (g)					
	N-S Direction		E-W Direction		Vertical Direction	
	Mass Center	Edge	Mass Center	Edge	Mass Center	Edge
281.90	1.48		1.56		1.25	
273.83	1.43		1.50		1.02	
265.83	1.38		1.43		0.85	
255.02	1.31		1.34		0.73	
244.21	1.23	1.28	1.26	1.30	0.68	0.71
224.00	1.09	1.13	1.11	1.17	0.66	0.68
200.00	0.90	0.94	0.94	0.98	0.61	0.63
169.93	0.69	0.71	0.72	0.75	0.53	0.55
162.00	0.63	0.65	0.67	0.68	0.51	0.53
141.50	0.49	0.50	0.54	0.54	0.45	0.47
131.68	0.43	0.44	0.47	0.48	0.41	0.44
112.50	0.40	0.41	0.37	0.38	0.35	0.40
104.12	0.38	0.40	0.38	0.40	0.32	0.38
100.00	0.38	0.40	0.39	0.41	0.31	0.34

Notes:
1. Enveloped response results at the north, south, east, and west edge nodes of the structure are shown. This is the maximum value of the response at any of these edge nodes.
2. Results at elevation 233.50′ are mid span of polar crane bridge.

Table 3.7.2-7

**MAXIMUM ABSOLUTE NODAL ACCELERATION (ZPA)
CONTAINMENT INTERNAL STRUCTURES**

HARD ROCK SITE CONDITION

Elevation (ft)	Maximum Absolute Nodal Acceleration, ZPA (g)					
	N-S Direction		E-W Direction		Vertical Direction	
	Mass Center	Edge	Mass Center	Edge	Mass Center	Edge
169.00 (PRZ Compartment)	1.26		1.67		0.48	
153.00 (SG-West Compartment)	0.75		0.72		0.43	
153.00 (SG-East Compartment)	1.40		0.67		0.40	
134.25	0.60	0.63	0.56	0.67	0.35	0.50
107.17	0.40	0.41	0.40	0.42	0.31	0.35
103.00	0.39	0.40	0.40	0.41	0.31	0.34
98.00	0.38	0.40	0.39	0.41	0.31	0.34
82.50	0.33	0.33	0.33	0.33	0.30	0.31
66.50	0.30	0.30	0.30	0.30	0.30	0.30

Note:
1. Enveloped response results at the north, south, east, and west edge nodes of the structure are shown. This is the maximum value of the response at any of these edge nodes.

Table 3.7.2-8

MAXIMUM DISPLACEMENT RELATIVE TO BOTTOM OF BASEMAT COUPLED AUXILIARY & SHIELD BUILDINGS

HARD ROCK SITE CONDITION

Elevation (ft)	Maximum Relative Displacement (in.)					
	N-S Direction		E-W Direction		Vertical Direction	
	Mass Center	Edge	Mass Center	Edge	Mass Center	Edge
333.13	1.51	1.52	1.60	1.62	0.35	0.62
295.23	1.14	1.15	1.20	1.22	0.34	0.60
265.00	0.89	0.90	0.96	0.99	0.09	0.42
242.50	0.74	0.75	0.81	0.84	0.08	0.40
220.00	0.59	0.60	0.66	0.69	0.08	0.37
200.00	0.46	0.47	0.53	0.56	0.07	0.34
179.56	0.33	0.34	0.40	0.43	0.06	0.30
164.51	0.25	0.26	0.32	0.34	0.06	0.27
153.98	0.21	0.22	0.27	0.28	0.05	0.25
134.87	0.15	0.15	0.19	0.21	0.05	0.27
116.50	0.09	0.09	0.11	0.12	0.04	0.19
99.00	0.03	0.04	0.04	0.05	0.02	0.11
81.50	0.01	0.01	0.01	0.02	0.01	0.04
66.50	0.00	0.00	0.00	0.00	0.00	0.00

Note:

1. The results at the edges are on the auxiliary building at and below the elevation 134.87′ and on the shield building above this elevation. This is the maximum value of the response at any of these edge nodes.

Table 3.7.2-9

MAXIMUM DISPLACEMENT RELATIVE TO BOTTOM OF BASEMAT STEEL CONTAINMENT VESSEL

HARD ROCK SITE CONDITION

Elevation (ft)	Maximum Relative Displacement (in.)					
	N-S Direction		E-W Direction		Vertical Direction	
	Mass Center	Edge	Mass Center	Edge	Mass Center	Edge
281.90	0.52		0.48		0.06	
273.83	0.50		0.46		0.05	
265.83	0.48		0.45		0.04	
255.02	0.46		0.42		0.03	
244.21	0.43	0.43	0.40	0.40	0.03	0.14
224.00	0.38	0.38	0.35	0.36	0.03	0.13
200.00	0.31	0.31	0.29	0.29	0.03	0.13
169.93	0.21	0.22	0.20	0.20	0.02	0.11
162.00	0.19	0.19	0.18	0.18	0.02	0.10
141.50	0.13	0.13	0.12	0.13	0.02	0.09
131.68	0.10	0.10	0.10	0.10	0.01	0.08
112.50	0.05	0.05	0.05	0.05	0.01	0.05
104.12	0.04	0.04	0.04	0.04	0.01	0.05
100.00	0.03	0.04	0.04	0.04	0.00	0.02

Notes:
1. Enveloped relative displacements at the north, south, east and west edge nodes of the structure are shown. This is the maximum value of the relative displacement at any of these edge nodes.
2. Results at elevation 233.50′ are mid span of polar crane bridge.

Table 3.7.2-10

MAXIMUM DISPLACEMENT RELATIVE TO BOTTOM OF BASEMAT CONTAINMENT INTERNAL STRUCTURES

HARD ROCK SITE CONDITION

Elevation (ft)	Maximum Relative Displacement (in.)					
	N-S Direction		E-W Direction		Vertical Direction	
	Mass Center	Edge	Mass Center	Edge	Mass Center	Edge
169.00	0.11		0.20		0.02	
153.00	0.08		0.11		0.02	
153.00	0.12		0.09		0.02	
134.25	0.06	0.07	0.07	0.08	0.01	0.04
107.17	0.04	0.04	0.04	0.04	0.01	0.02
103.00	0.03	0.04	0.04	0.04	0.01	0.02
98.00	0.03	0.03	0.03	0.04	0.01	0.02
82.50	0.01	0.01	0.01	0.01	0.00	0.02
66.50	0.00	0.00	0.00	0.00	0.00	0.00

Note:
1. Enveloped relative displacements at the north, south, east, and west edge nodes of the structure are shown. This is the maximum value of the relative displacement at any of these edge nodes.

Table 3.7.2-11

MAXIMUM FORCES AND MOMENTS
COUPLED AUXILIARY AND SHIELD BUILDINGS

HARD ROCK SITE CONDITION

Elevation (ft)	Maximum Forces ($x10^3$ Kips)			Maximum Moment ($x10^3$ K-ft)		
	Axial	N-S Shear	E-W Shear	Torque	@ N-S Axis	@ E-W Axis
333.13						
	2.81	6.53	6.42	23.87		
295.23					266.61	260.99
	16.02	16.27	15.47	78.18		
265					854.17	872.74
	18.6	22.38	21.16	194.53		
242.5					1315.66	1374.77
	20.59	25.51	24.71	261.26		
220					1921.62	1989.93
	22.41	28.04	27.13	313.52		
200					2506.1	2583.91
	23.96	30.08	28.66	361.09		
179.56					3127.81	3222.6
	25.13	24.65	21.7	870.19		
164.51					3479.65	3608.09
	26.97	16.47	22.76	1050.1		
153.98					3723.93	3806.91
145.37						
	30.4	13.91	18.31	563.29		
134.88					3992.65	4257.4
	36.1	42.65	47.85	1025.33		
116.5					5428.61	6202.96
	43.02	48.8	55.11	1205.06		
99					6373.05	7146.7
	50.8	25.88	16.83	1575.79		
81.5					6613.75	7499.97
	35.32	15.68	10.27	633.76		
66.5					2474.44	3855.1
	77.9	51.35	47.75	1463.52		
60.5					3295.23	9050.29

Note:

1. The forces in the shear beam between elevation 60.5′ and 99′ are those in the auxiliary and shield building stick. There is a parallel shear beam for the basemat of the containment internal structures.

Table 3.7.2-12

MAXIMUM FORCES AND MOMENTS
STEEL CONTAINMENT VESSEL

HARD ROCK SITE CONDITION

Elevation (ft)	Maximum Forces ($x10^3$ Kips)			Maximum Moment ($x10^3$ K-ft)		
	Axial	N-S Shear	E-W Shear	Torque	@ N-S Axis	@ E-W Axis
281.9						
	0.24	0.27	0.28	0		
273.83					2.29	2.16
	0.6	0.73	0.77	0.93		
265.83					10.26	9.54
	0.88	1.19	1.25	2.57		
255.02					26.95	25.1
	1.16	1.66	1.73	5.01		
244.21					50.45	47.1
	1.53	2.28	2.36	8.62		
224					105.31	99.26
	2.8	4.81	4.23	25.56		
200					215.37	249.37
	3.36	5.6	5	29.38		
169.93					365.53	427.69
	3.83	6.19	5.57	32.78		
162					416.28	485.37
	4.11	6.52	5.89	34.85		
141.5					541.12	624.26
	4.36	6.76	6.11	37.2		
138.58					561.81	647.61
	4.36	6.76	6.11	37.2		
131.68					604.02	694.26
	4.61	6.96	6.3	38.83		
112.5					727.75	831.63
	4.79	7.07	6.37	39.67		
110.5					741.5	848.17
	4.79	7.07	6.37	39.67		
104.12					782.14	893.22
	4.86	7.1	6.4	39.95		
100					808.94	923.25

Table 3.7.2-13

**MAXIMUM FORCES AND MOMENTS
CONTAINMENT INTERNAL STRUCTURES**

HARD ROCK SITE CONDITION

Elevation (ft)	Maximum Forces ($x10^3$ Kips)			Maximum Moment ($x10^3$ K-ft)		
	Axial	N-S Shear	E-W Shear	Torque	@ N-S Axis	@ E-W Axis
169						
	0.01	0.39	0.52	3.27		
163.79					3.22	2.55
	0.14	0.55	0.72	4.44		
153					10.91	8.45
	0.52	1.2	2.13	18.3		
134.25					54.83	32.8
Above Elevation 135.25′, East SG Compartment						
153						
	0.15	0.68	2.32	0.59		
134.25					50.97	14.03
Below Elevation 135.25′						
	0	7.43	7.19	112.93		
121.5					183.55	139
	3.26	7.43	7.19	112.93		
107.17					286.6	236.34
	6.69	11.2	9.74	274.61		
103					407.28	293.3
	10.52	38.11	49.81	324.99		
98					395.94	375.75
	19.59	44.71	55.11	377.26		
82.5					1780.56	1610.91
	68.58	69.93	69.29	1173.07		
66.5					5946.55	5621.72

Note:
1. The forces in the shear beam between elevation 60.5′ and 98′ are those in the containment internal structures stick. There is a parallel shear beam for the basemat of the auxiliary and shield building.

Table 3.7.2-14

SUMMARY OF MODELS AND ANALYSIS METHODS

Model	Analysis Method	Program	Type of Dynamic Response/Purpose
3D finite element model of the shield building roof	Modal analysis Equivalent static analysis using nodal accelerations from 3D shell model	ANSYS GT STRUDL	To obtain dynamic properties. To obtain SSE member forces for the shield building roof.
3D finite element shell dynamic model of auxiliary and shield building	Modal analysis	ANSYS	To obtain dynamic properties.
3D finite element shell model of containment internal structures	Modal analysis Equivalent static analysis using nodal accelerations and member forces from 3D stick model	ANSYS	To obtain dynamic properties. Performed for the hard rock profile with equivalent static acceleration input. To obtain forces for the design of floors and walls of the containment internal structures.
3D shell of revolution model of steel containment vessel	Modal analysis Equivalent static analysis using nodal accelerations from 3D stick model	ANSYS	To obtain dynamic properties. To obtain SSE stresses for the containment vessel.
3D lumped mass stick model of Nuclear Island	Modal analysis Mode superposition time history analysis	ANSYS	To obtain dynamic properties. Performed for hard rock profile. To develop time histories for generating seismic response spectra. To obtain the following: Maximum absolute nodal accelerations (ZPA). Maximum displacements relative to basemat. Maximum member forces and moments.
3D finite element shell dynamic model of nuclear island (coupled auxiliary/shield building shell model, with superelement of containment internal structures)	Mode superposition time history analysis	ANSYS	Performed for hard rock profile. To develop time histories for generating vertical response spectra for auxiliary building and flexible floors. To obtain maximum absolute nodal accelerations (ZPA) for flexible floors and walls and for shield building roof.
3D finite element refined shell model of auxiliary and shield building	Equivalent static analysis using nodal accelerations from 3D stick model	ANSYS	Performed for the hard rock profile with equivalent static acceleration input. To obtain the forces for the design of floors and walls of the auxiliary and shield building.

Table 3.7.2-15

**COMPARISON OF FREQUENCIES
FOR CONTAINMENT VESSEL SEISMIC MODEL**

Mode No.	Vertical Model		Horizontal Model	
	Shell of Revolution Model	**Stick Model**	**Shell of Revolution Model**	**Stick Model**
1	16.51 hertz	16.97 hertz	6.20 hertz	6.31 hertz
2	23.26 hertz	28.20 hertz	18.58 hertz	18.96 hertz

Table 3.7.2-16

SUMMARY OF DYNAMIC ANALYSES & COMBINATION TECHNIQUES

Model	Analysis Method	Program	Three Components Combination	Modal Combination
3D lumped mass stick, fixed base models	Mode superposition time history analysis	ANSYS	Algebraic Sum	n/a
3D finite element, fixed base models, coupled auxiliary/shield building shell model, with superelement of containment internal structures	Mode superposition time history analysis	ANSYS	Algebraic Sum	n/a
3D finite element, fixed base models, coupled auxiliary/shield buildings and containment internal structures	Equivalent static analysis using nodal accelerations from 3D stick model	ANSYS	SRSS or 100%, 40%, 40%	n/a
3D finite element model of the nuclear island basemat	Equivalent static analysis using nodal accelerations from 3D stick model	ANSYS	100%, 40%, 40%	n/a
3D shell of revolution model of steel containment vessel	Equivalent static analysis using nodal accelerations from 3D stick model	ANSYS	SRSS or 100%, 40%	n/a
3D finite element model of the shield building roof	Equivalent static analysis using nodal accelerations from 3D stick model	ANSYS GT STRUDL	SRSS	n/a
PCS valve room and miscellaneous steel frame structures, miscellaneous flexible walls, and floors	Response spectrum analysis	ANSYS	SRSS	Grouping

Table 3.7.3-1 (Sheet 1 of 3)

SEISMIC CATEGORY I EQUIPMENT OUTSIDE CONTAINMENT BY ROOM NUMBER

Room No.	Room Name	Equipment Description
12101	Division A battery room	Batteries
12102	Division C battery room 1	Batteries
12103	Spare battery room	Spare batteries
12104	Division B battery room 1	Batteries
12105	Division D battery room	Batteries
12113	Spare battery charger room	
12162	RNS pump room A	RNS pressure boundary
12163	RNS pump room B	RNS pressure boundary
12201	Division A dc equipment room	dc equipment
12202	Division C battery room 2	Batteries
12203	Division C dc equipment room	dc equipment
12204	Division B battery room 2	Batteries
12205	Division D dc equipment room	dc equipment
12207	Division B dc equipment room	dc equipment
12211	Corridor	Divisional cables
12212	Division B RCP trip switchgear room	RCP trip switchgear
12244	Lower annulus valve area	CVS/WLS containment isolation valves
12251	Demineralizer/filter access area	CVS/DWS isolation valves
12254	SFS penetration room	SFS containment isolation valve
12256	Containment isolation valve room	RNS containment isolation valves
12259	Pipe chase	RNS piping
12262	Piping/Valve room	RNS pressure boundary, SFS piping
12265	Waste monitor tank room C	SFS piping
12269	Pipe chase	RNS pressure boundary
12300	Corridor	Divisional cable
12301	Division A I&C room	Divisional I&C
12302	Division C I&C room	Divisional I&C

Table 3.7.3-1 (Sheet 2 of 3)

SEISMIC CATEGORY I EQUIPMENT OUTSIDE CONTAINMENT BY ROOM NUMBER

Room No.	Room Name	Equipment Description
12303	Remote shutdown room	Divisional cabling
12304	Division B I&C/penetration room	Divisional I&C/electrical penetrations
12305	Division D I&C/penetration room	Divisional I&C/electrical penetrations
12306	Valve/piping penetration room	CCS/CVS/DWS/FPS/SGS containment isolation valves
12311	Corridor	Divisional cabling
12312	Division C RCP trip switchgear room	RCP trip switchgear
12313	Division C I&C/penetration room	Divisional I&C/electrical penetrations
12321	Non-1E equipment/penetration room	Divisional cabling
12341	Middle annulus	Class 1E electrical penetrations Various mechanical piping penetrations
12351	Maintenance floor staging area	Divisional cabling (ceiling)
12352	Personnel hatch	Personnel airlock (interlocks)
12354	Middle annulus access room	PSS/SFS containment isolation valves
12362	RNS HX room	RNS pressure boundary
12365	Waste monitor tank room B	SFS piping
12400	Control room vestibule	Control room access
12401	Main control room	Dedicated safety panel VBS HVAC dampers VES isolation valves Lighting circuits Mounting for lighting fixtures
12404	Lower MSIV compartment B	SGS containment isolation valves, instrumentation and controls
12405	Lower VBS B and D equipment room	VWS/PXS/CAS containment isolation valves
12406	Lower MSIV compartment A	SGS containment isolation valves, instrumentation and controls
12412	Electrical penetration room Division A	Divisional electrical penetrations

Table 3.7.3-1 (Sheet 3 of 3)

SEISMIC CATEGORY I EQUIPMENT OUTSIDE CONTAINMENT BY ROOM NUMBER

Room No.	Room Name	Equipment Description
12421	Non 1E equipment/penetration room	Divisional cabling
12422	Reactor trip switchgear II	Reactor trip switchgear
12423	Reactor trip switchgear I	Reactor trip switchgear
12452	VFS penetration room	VFS containment isolation valves, divisional cabling
12454	VFS/SFS/PSS penetration room	SFS/PSS/VFS containment isolation valves, RNS pressure boundary
12462	Cask washdown pit	SFS piping
12504	Upper MSIV compartment B	SGS CIVs, instrumentation and controls
12506	Upper MSIV compartment A	SGS CIVs, instrumentation and controls
12541	Upper annulus	PCS piping and cabling PCS air baffle
12553	Personnel access area	Personnel airlock (interlocks)
12555	Operating deck staging area/VES air storage	VES high pressure air bottles
12562	Fuel handling area	Spent fuel storage racks
12701	PCS valve room	PCS isolation valves/instrumentation
12703	PCS water storage tank	PCS piping, level and temperature instrumentation

Table 3.7.3-2

EQUIPMENT CLASSIFIED AS SENSITIVE TARGETS FOR SEISMICALLY ANALYZED PIPING, HVAC DUCTING, CABLE TRAYS

Component	Discussion	Zone of Protection
Seismic Category I Valve No Class 1E Electrical Equipment Not pressure sensitive	These are manual valves. The actuator must be protected from impact.	Valve body and actuator area
Seismic Category I Valve Class 1E Electrical Equipment Pressure sensitive	These valves have sensitive Class 1E equipment (e.g., Position indicators, limit switches, motor operator) or solenoid valves.	One support (acting in direction of impact) on each side of valve
Seismic Category I Dampers	The actuator must be protected along with any Class 1E equipment.	Within one support (acting in direction of impact) on each side of HVAC
Monitors	This includes: neutron detectors, radiation monitors, resistance temperature detectors, speed sensors, thermocouples, and transmitters.	Monitors and associated wiring
Sensitive Electrical Equipment Housed in Cabinets, Panels or Boards	This includes: relays, contractors, breakers, and switchgear.	Cabinets, panels, and boards housing sensitive devices
Class 1E exposed cables and wiring	Cables and wiring which are not housed in cable trays or conduits must be protected.	Exposed cables and wiring
Device or Instrument Tubing	Any device or tubing that could be damaged resulting in the loss of the pressure boundary of a safety class line.	Device or tubing
Penetrations	Rigid penetrations are considered robust. Floating penetrations with bellows are considered sensitive.	Floating penetration and associated bellows

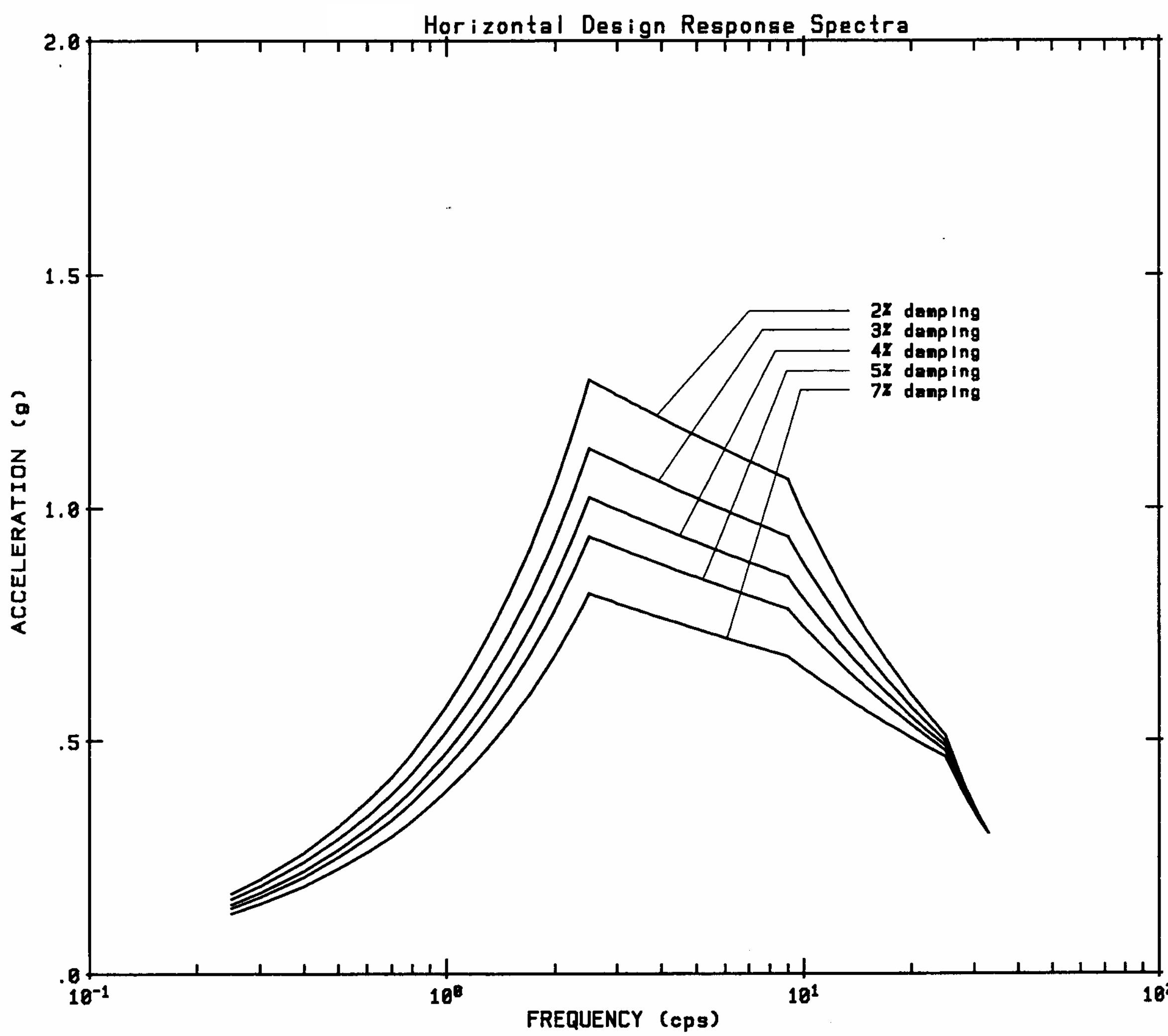


Figure 3.7.1-1

Horizontal Design Response Spectra
Safe Shutdown Earthquake

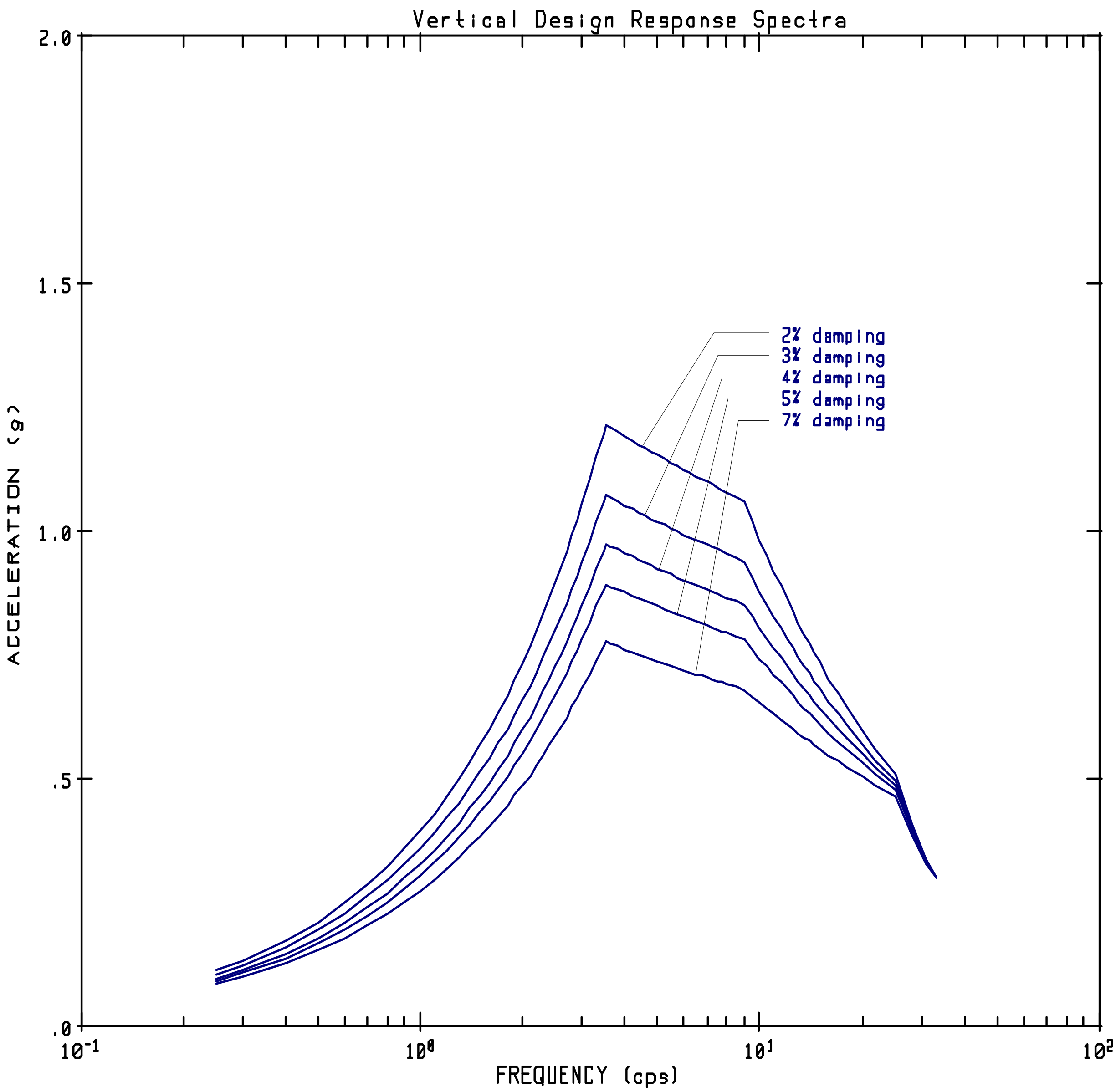


Figure 3.7.1-2

Vertical Design Response Spectra
Safe Shutdown Earthquake

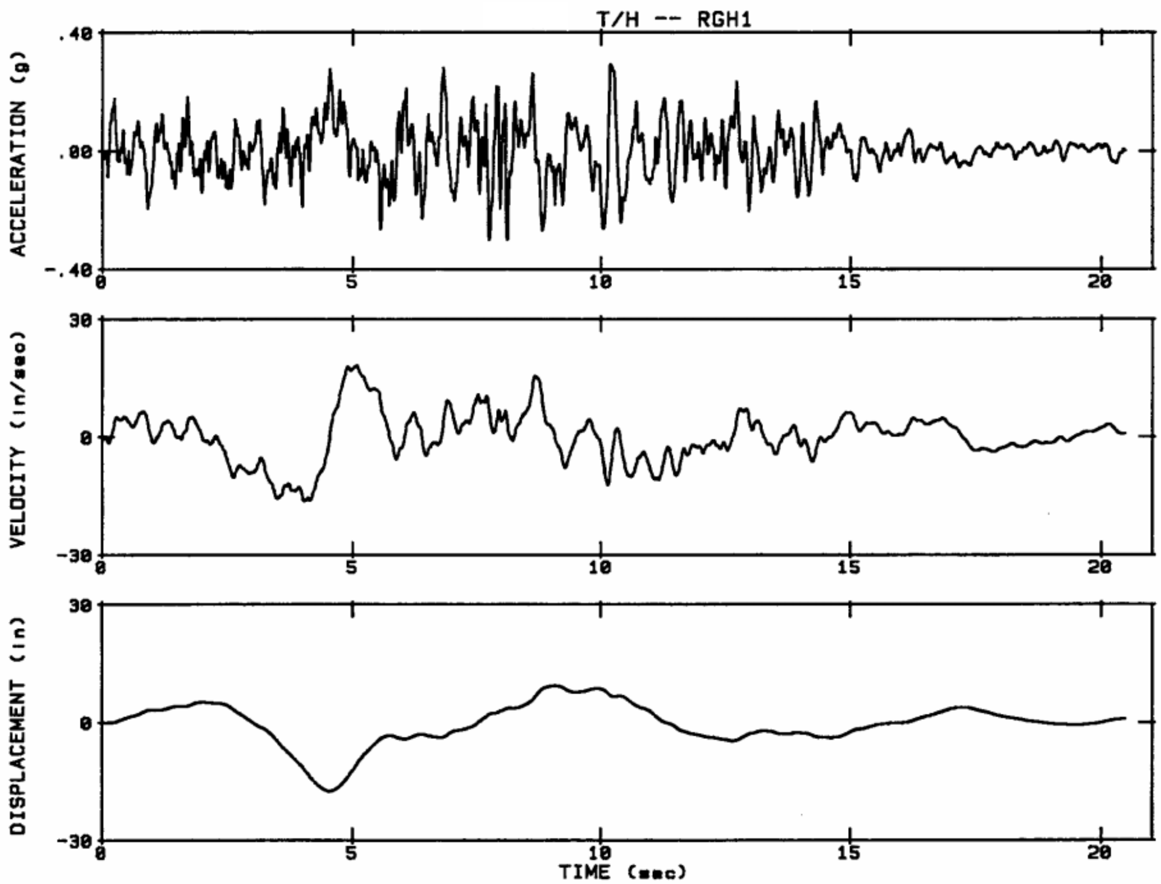


Figure 3.7.1-3

Design Horizontal Time History, "H1"
Acceleration, Velocity & Displacement Plots

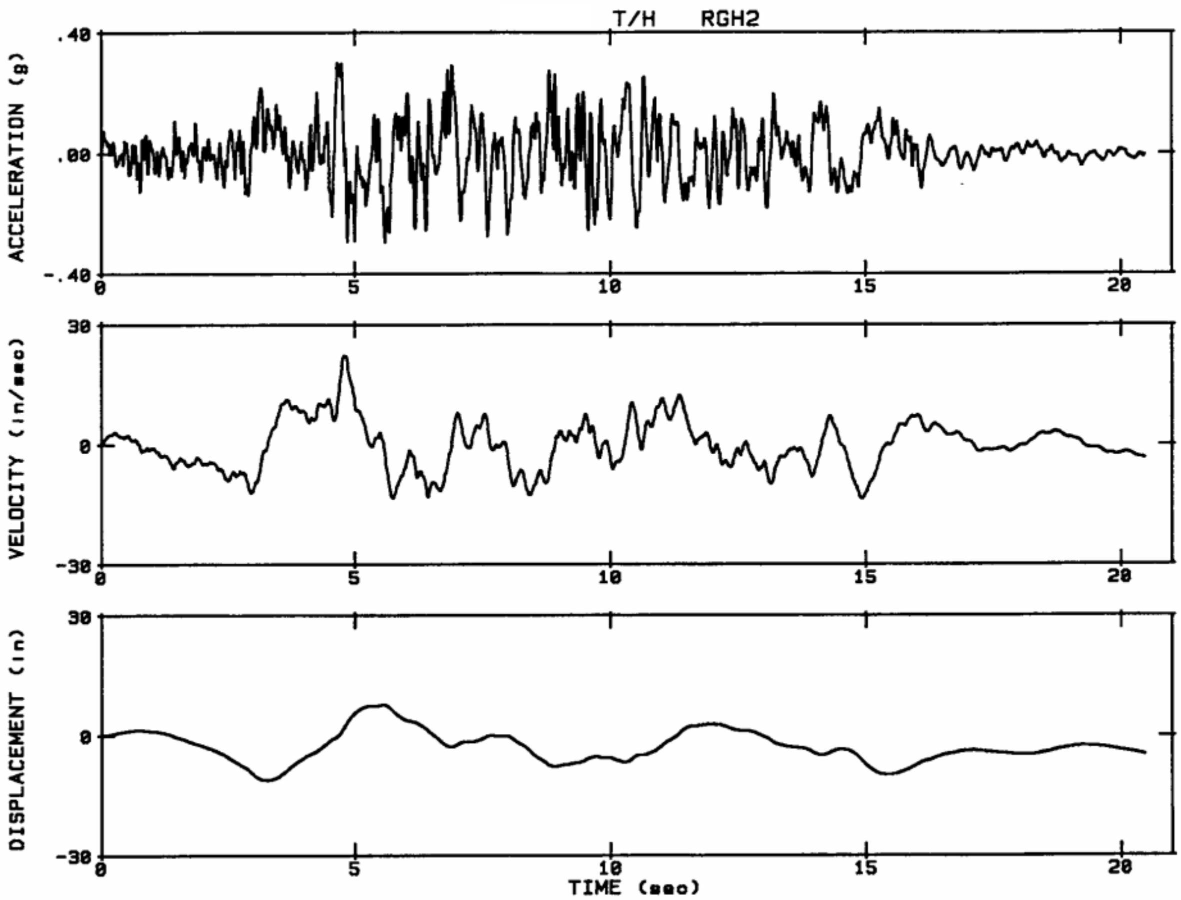


Figure 3.7.1-4

**Design Horizontal Time History, "H2"
Acceleration, Velocity & Displacement Plots**

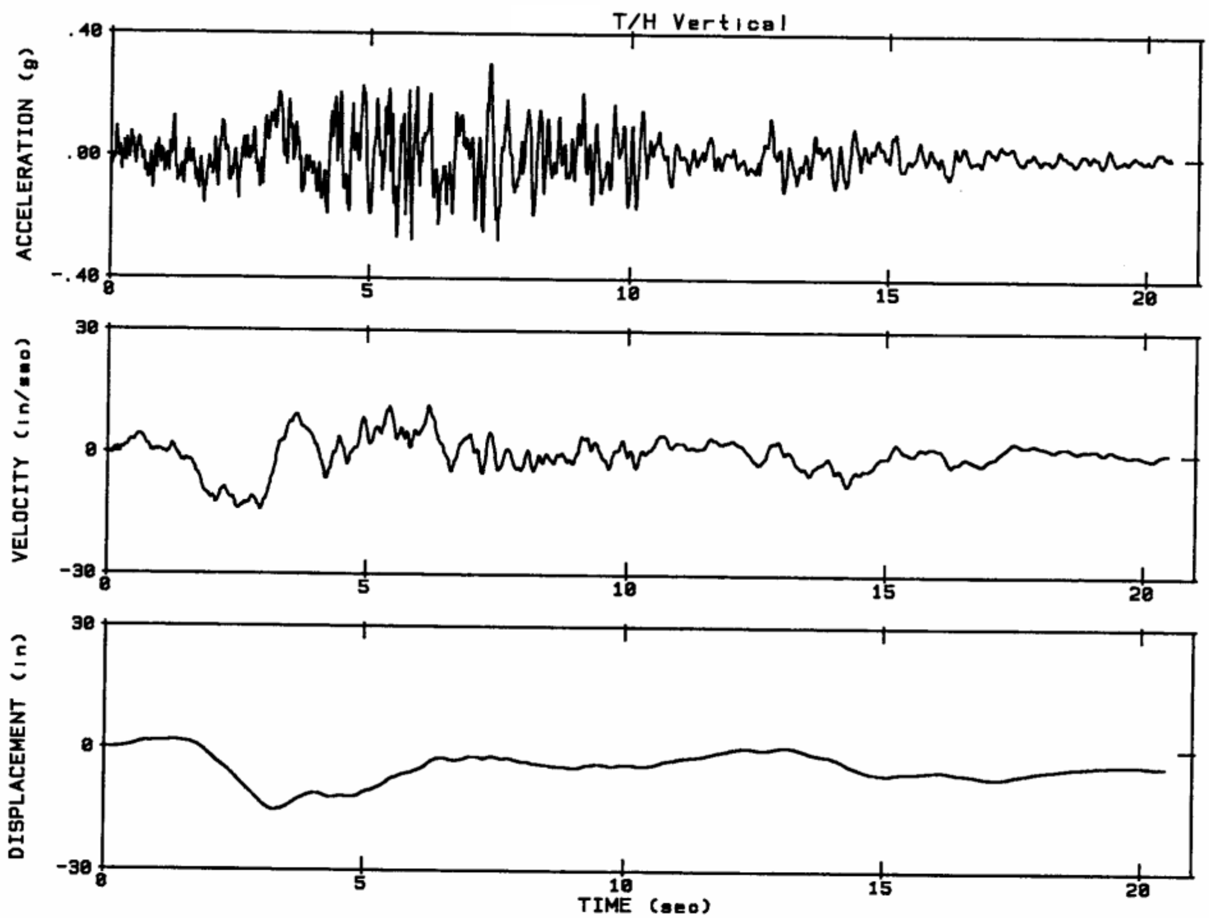


Figure 3.7.1-5

**Design Vertical Time History
Acceleration, Velocity & Displacement Plots**

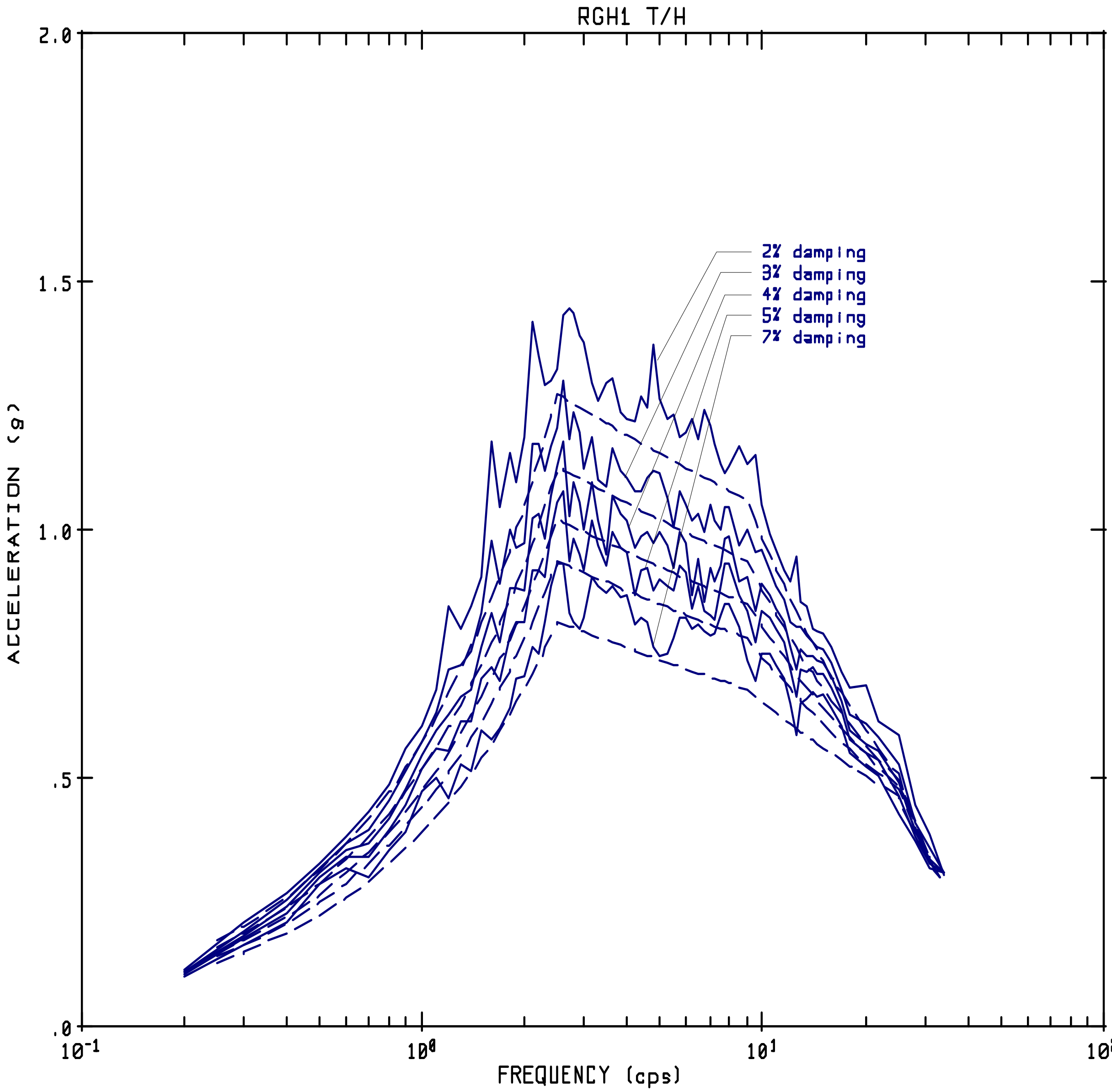


Figure 3.7.1-6

Acceleration Response Spectra of Design Horizontal Time History, "H1"

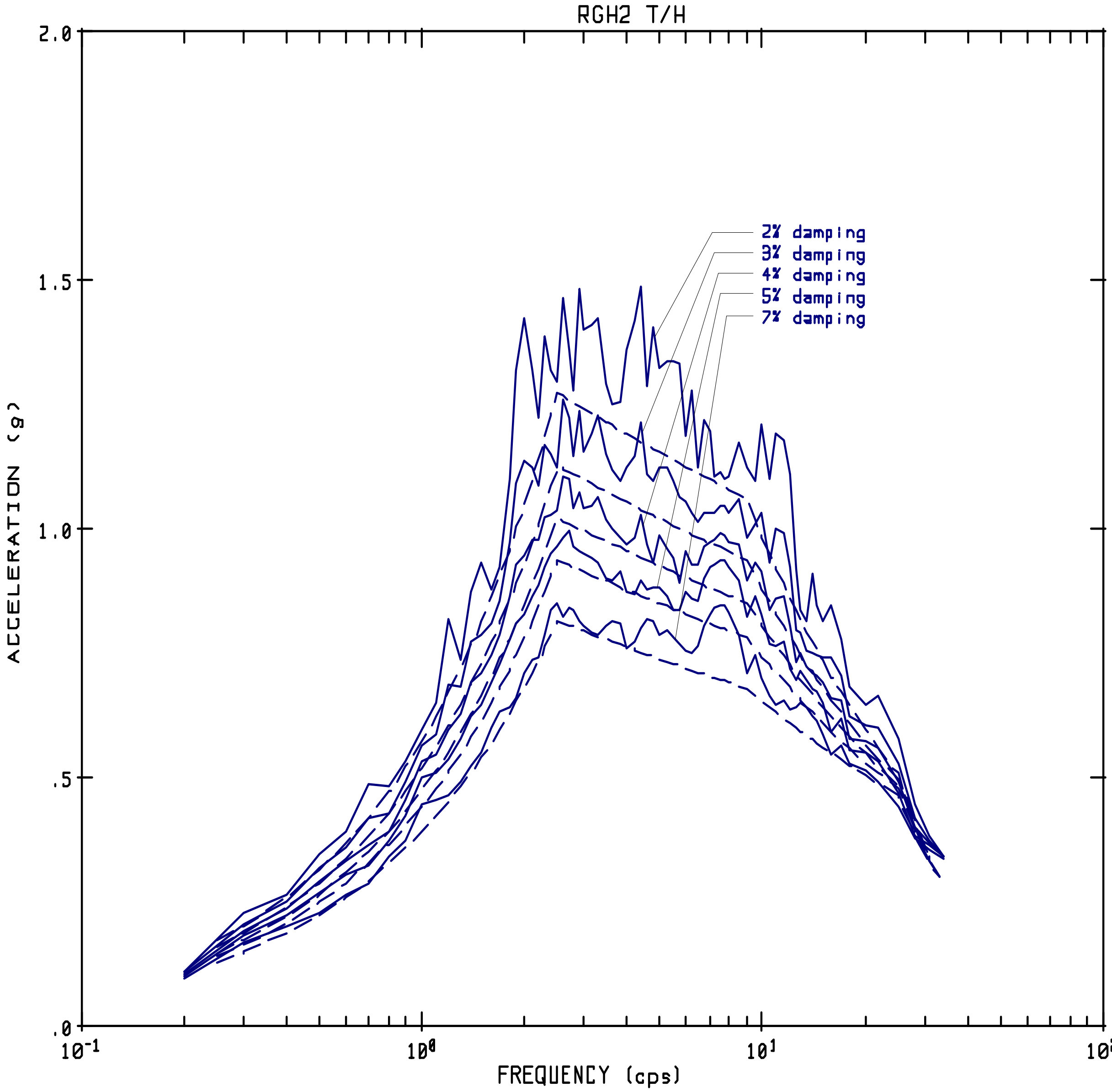


Figure 3.7.1-7

Acceleration Response Spectra of Design Horizontal Time History, "H2"

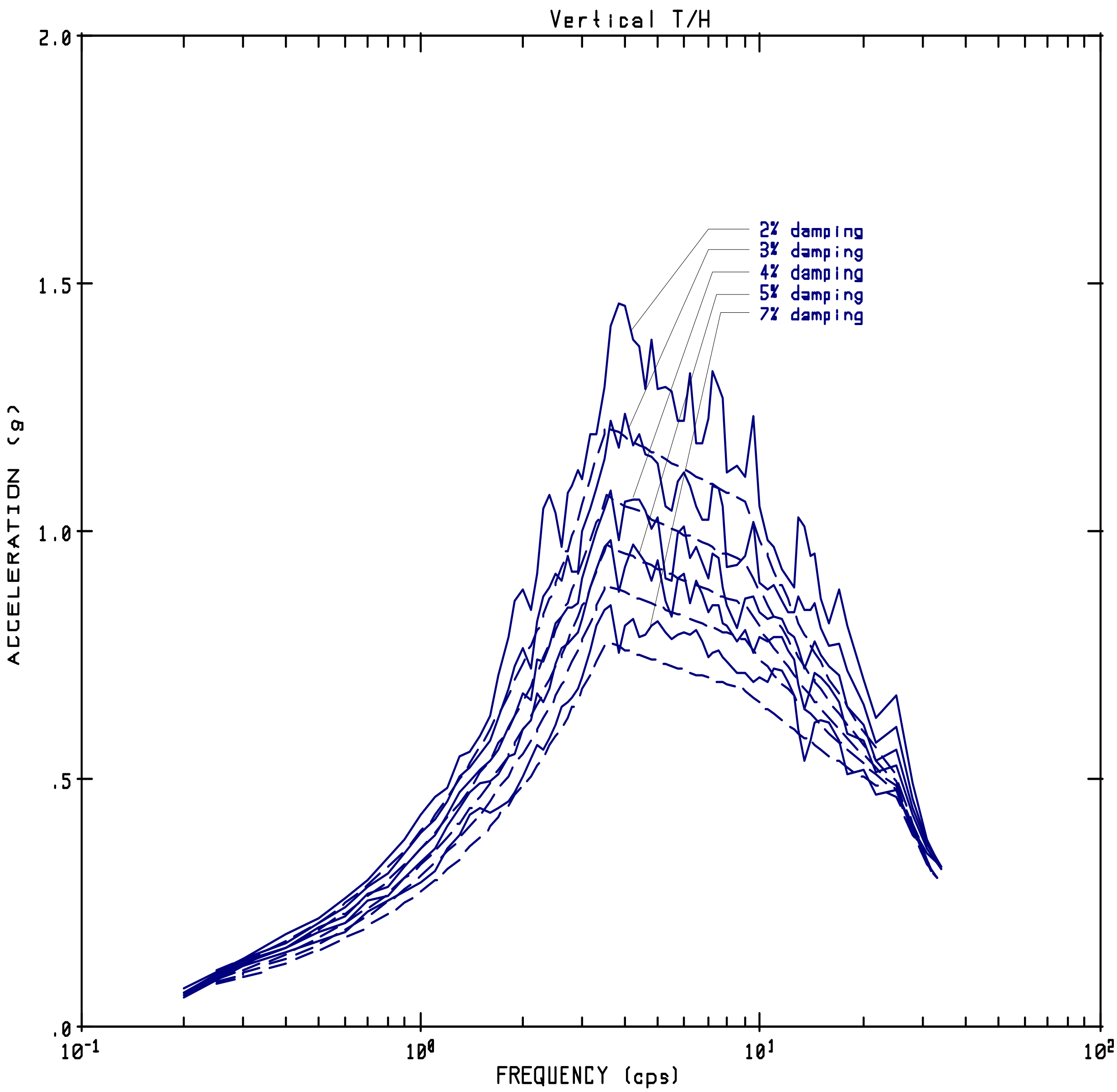


Figure 3.7.1-8

Acceleration Response Spectra of Design Vertical Time History

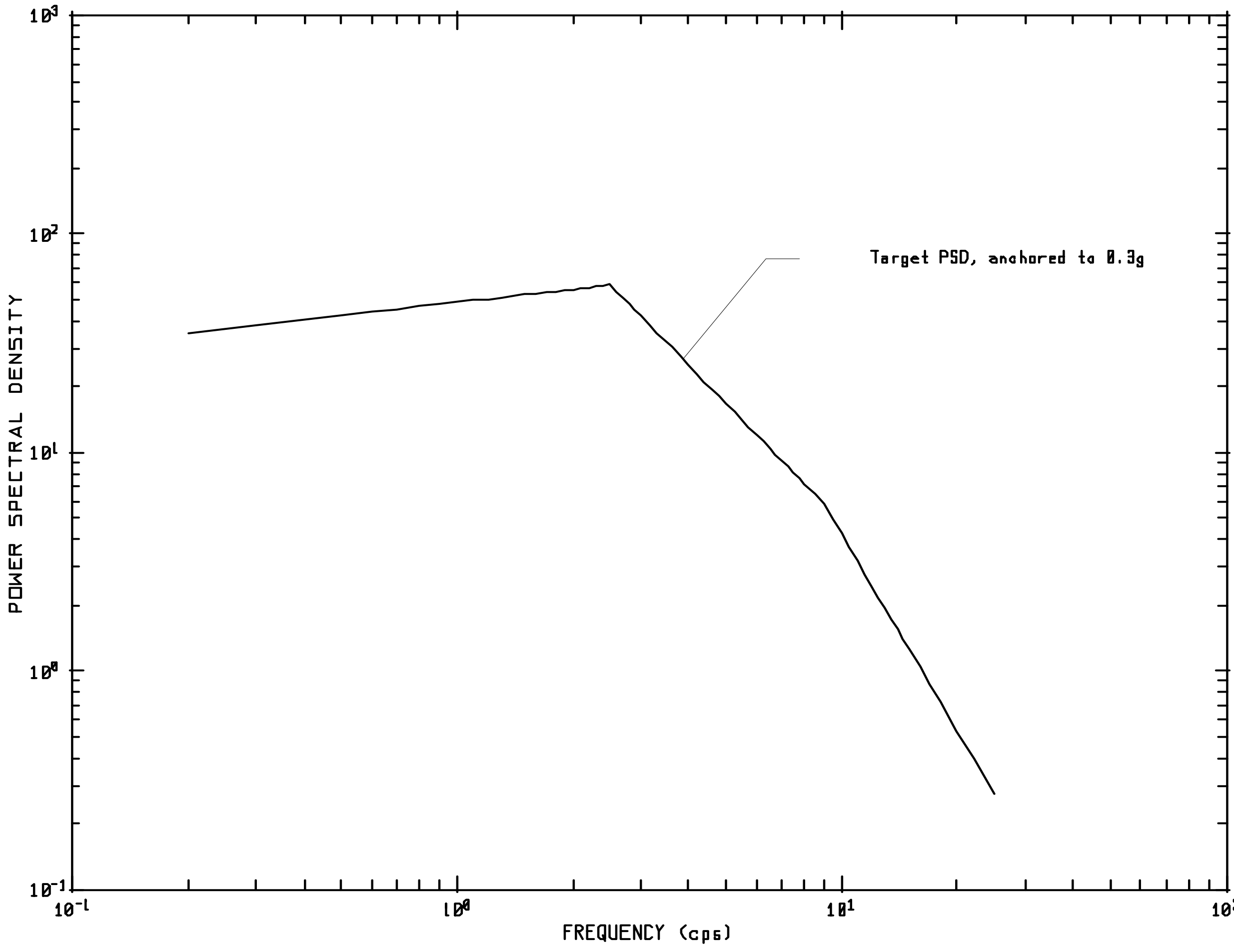


Figure 3.7.1-9

Minimum Power Spectral Density Curve (Normalized to 0.3g)

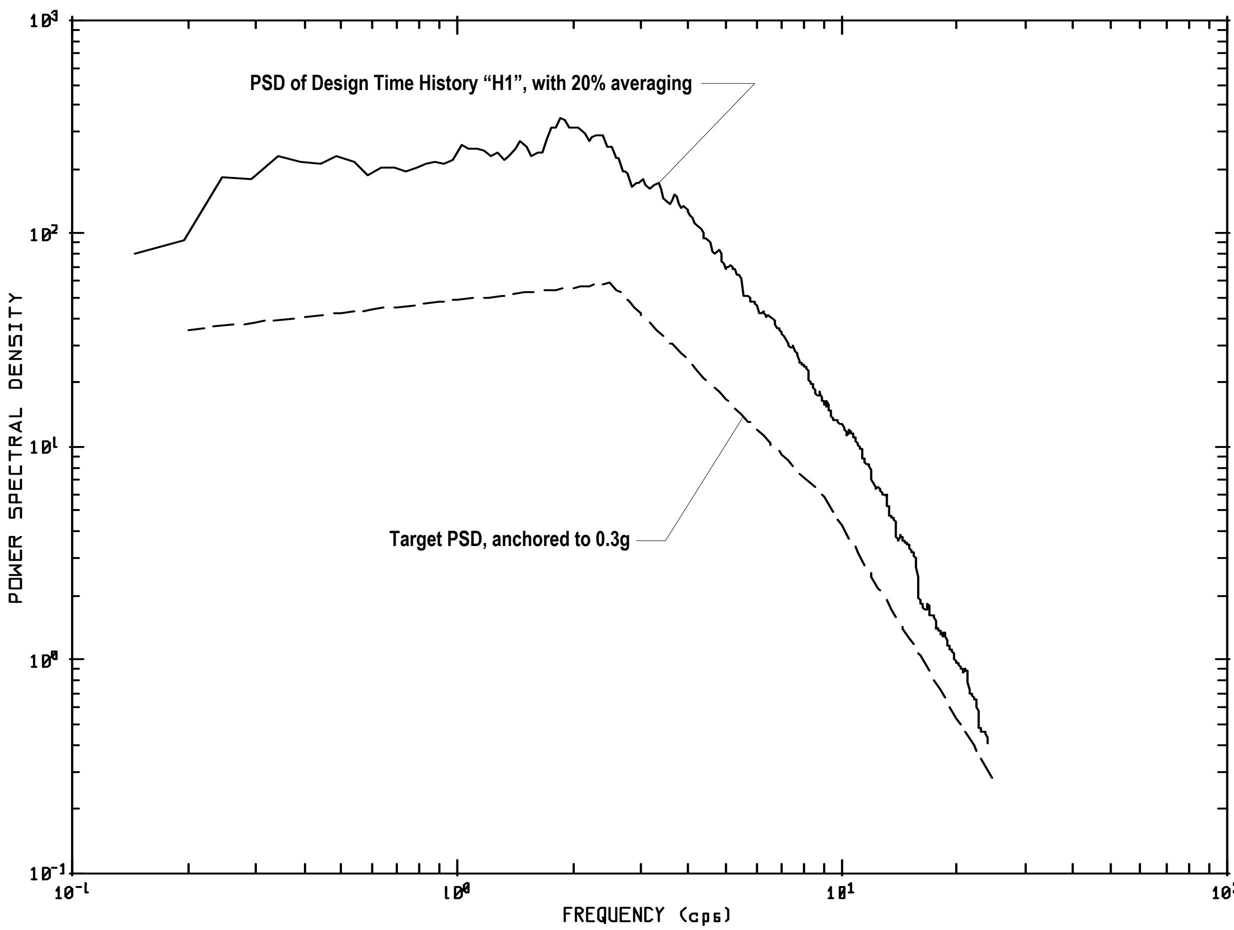


Figure 3.7.1-10

Power Spectral Density of Design Horizontal Time History, "H1"

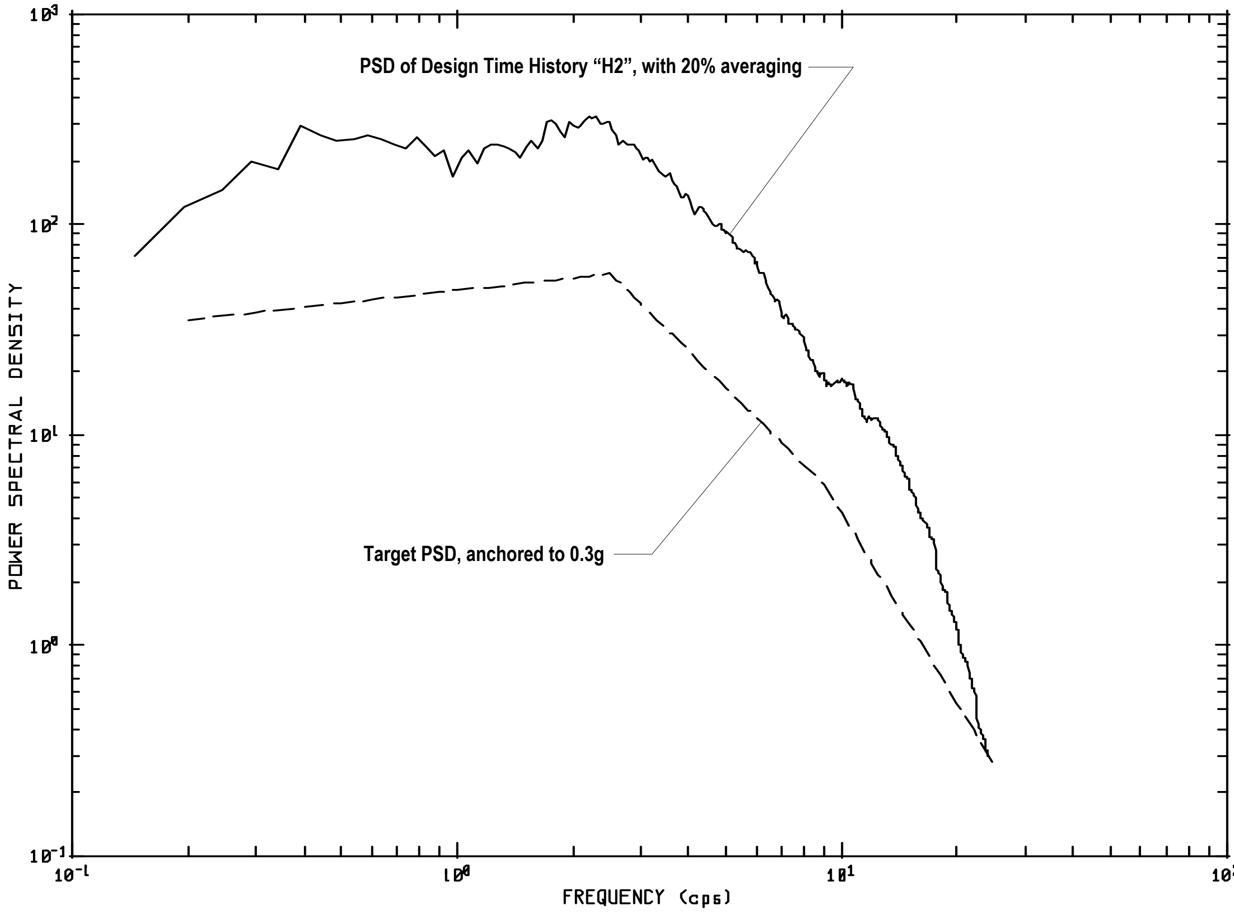


Figure 3.7.1-11

**Power Spectral Density of
Design Horizontal Time History, "H2"**

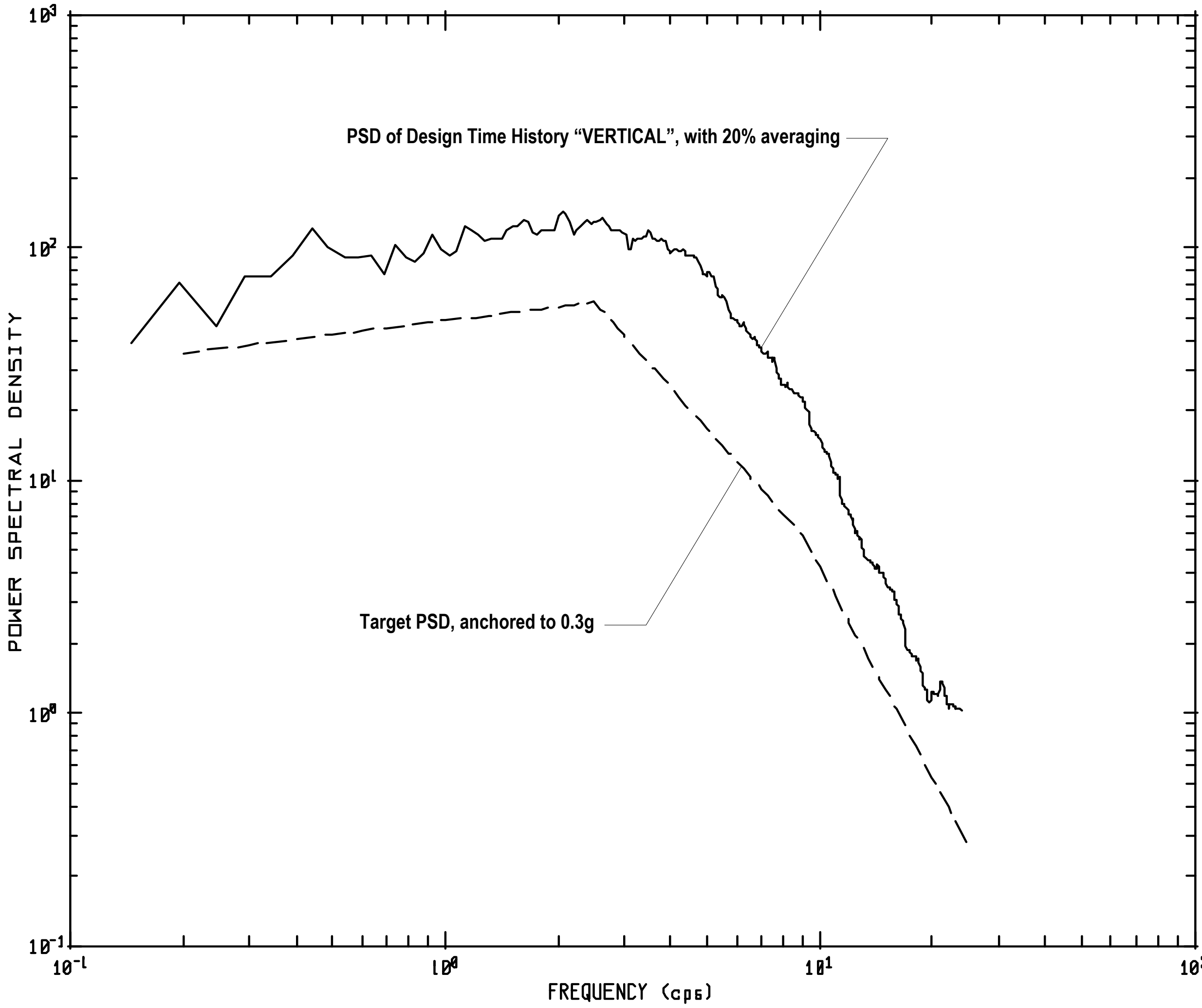
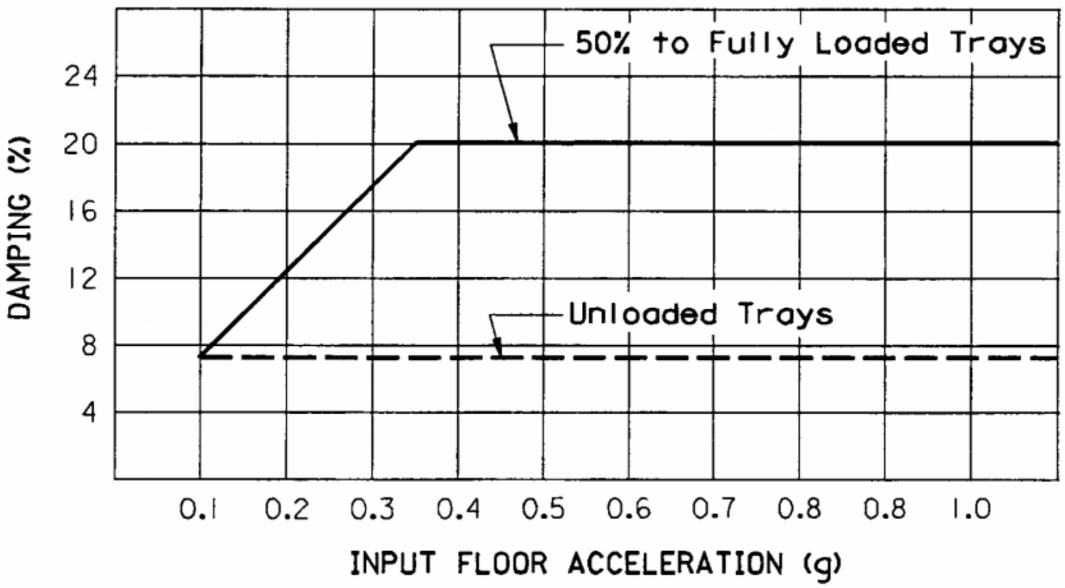


Figure 3.7.1-12

**Power Spectral Density of
Design Vertical Time History**



Notes:

- The damping value curve shown is applicable for 50% to fully loaded cable trays.
- For cable trays loaded to less than 50%, linear interpolated damping values shall be used.
- For unloaded cable trays, damping value equal to 7% of critical shall be used for all floor acceleration values.

Figure 3.7.1-13

Damping Values for Cable Trays & Supports

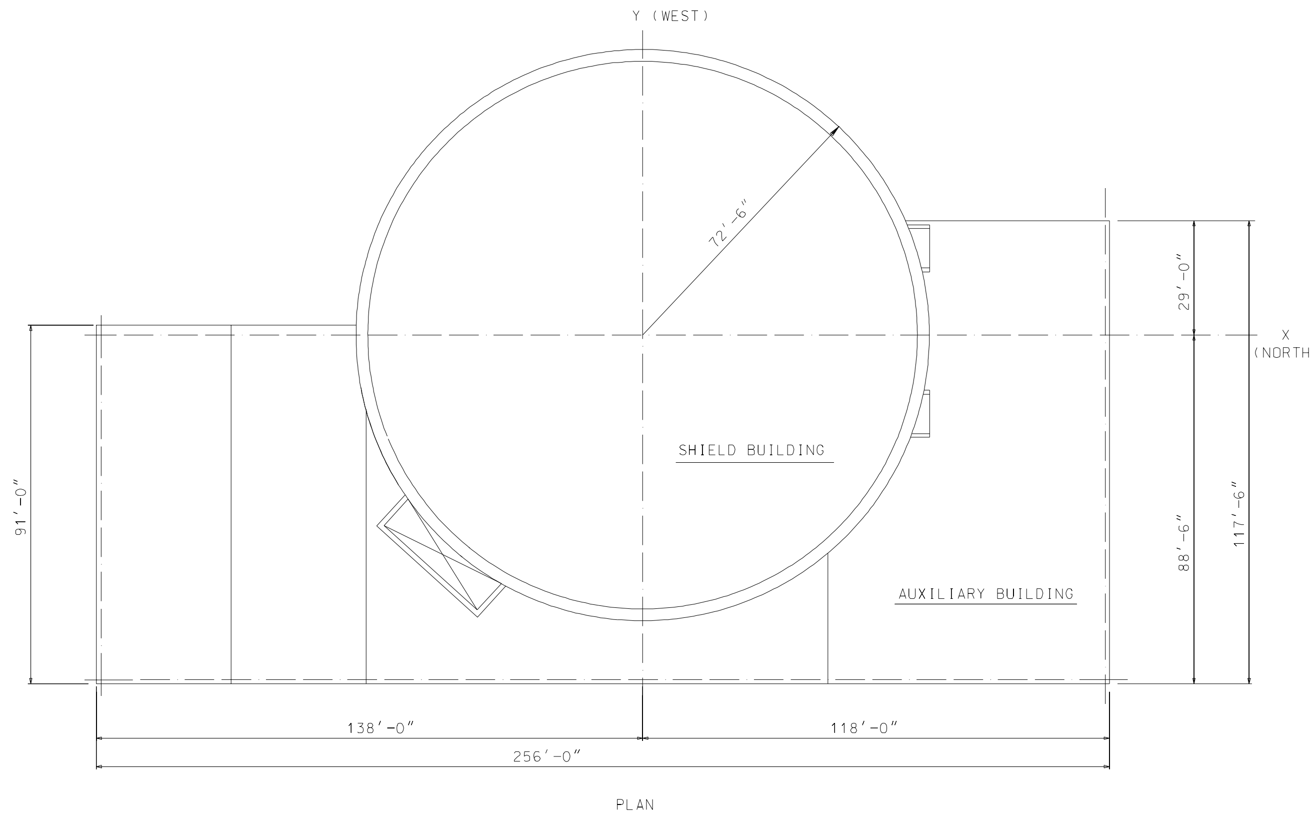


Figure 3.7.1-14

[*Nuclear Island Structures Dimensions*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

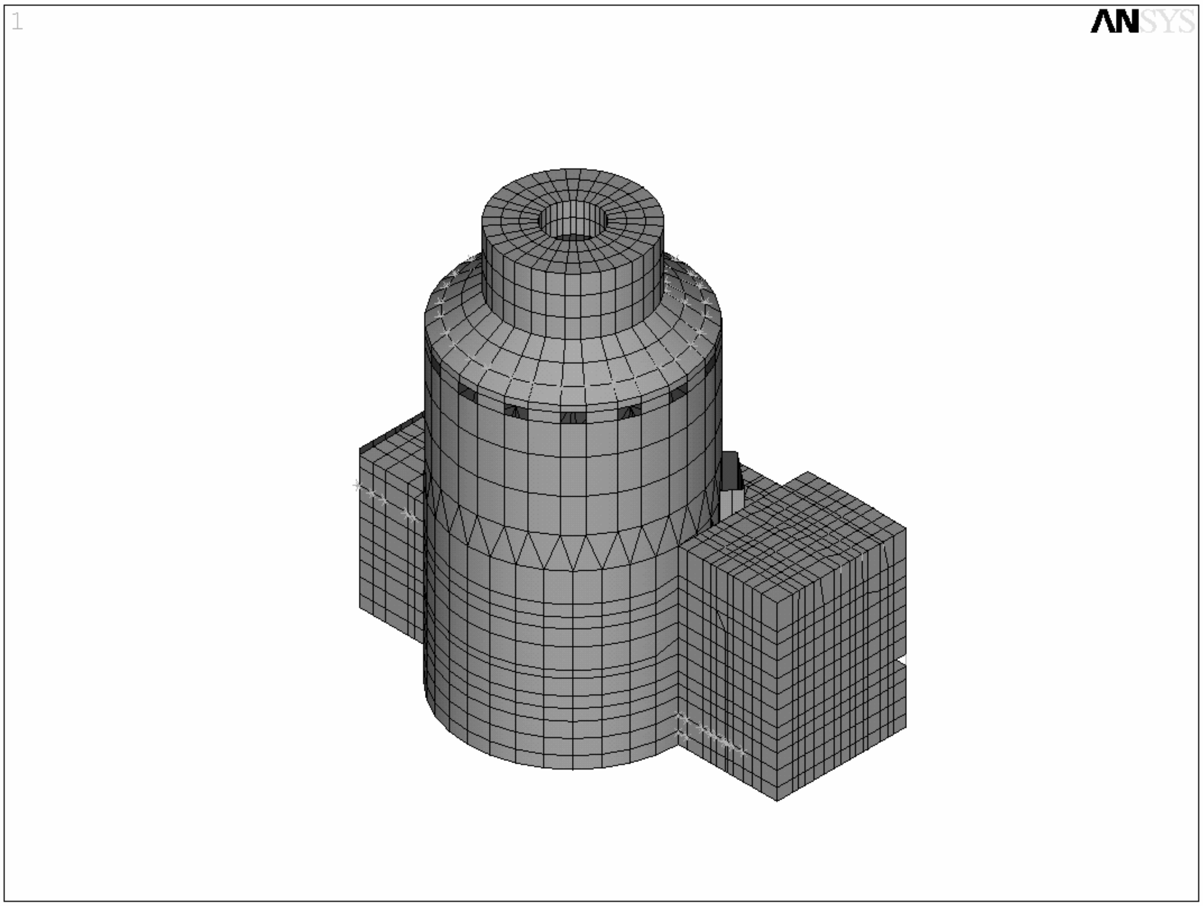
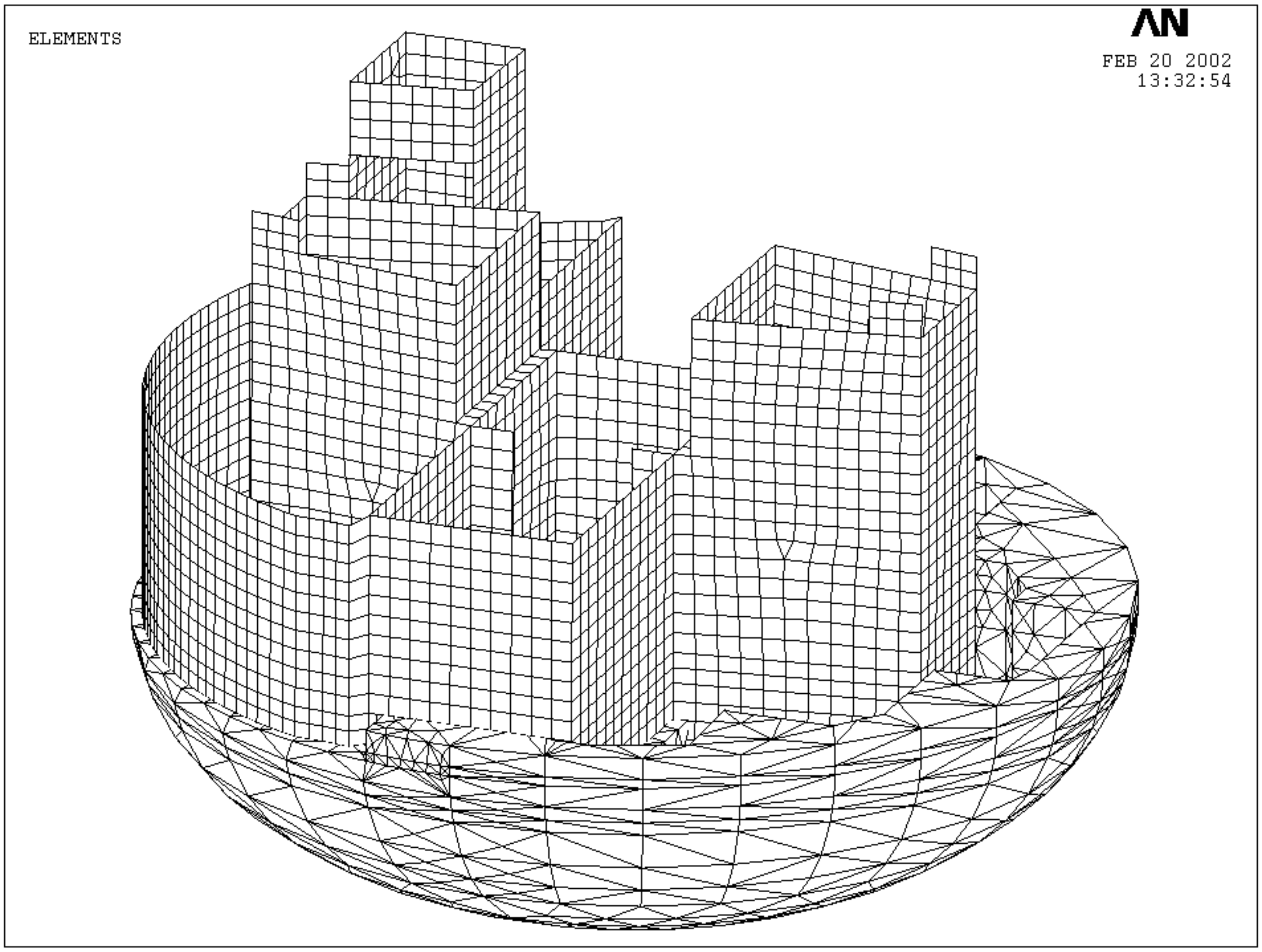


Figure 3.7.2-1

**3-D Finite Element Model of
Coupled Shield & Auxiliary Building**



Note: This figure shows the finite element model of walls and basemat inside containment. Floors are not shown.

Figure 3.7.2-2

3-D Finite Element Model of Containment Internal Structures

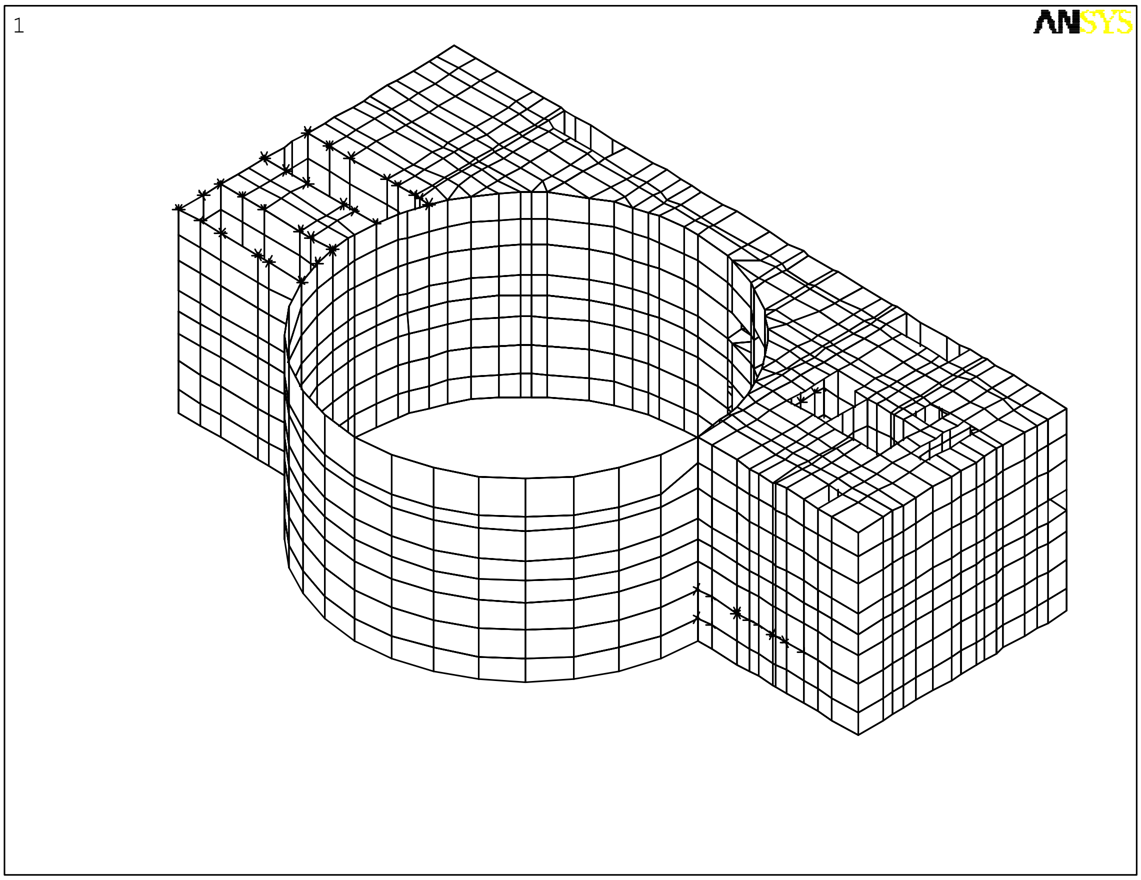


Figure 3.7.2-3

**Coupled Shield & Auxiliary Building
Finite Element Model**

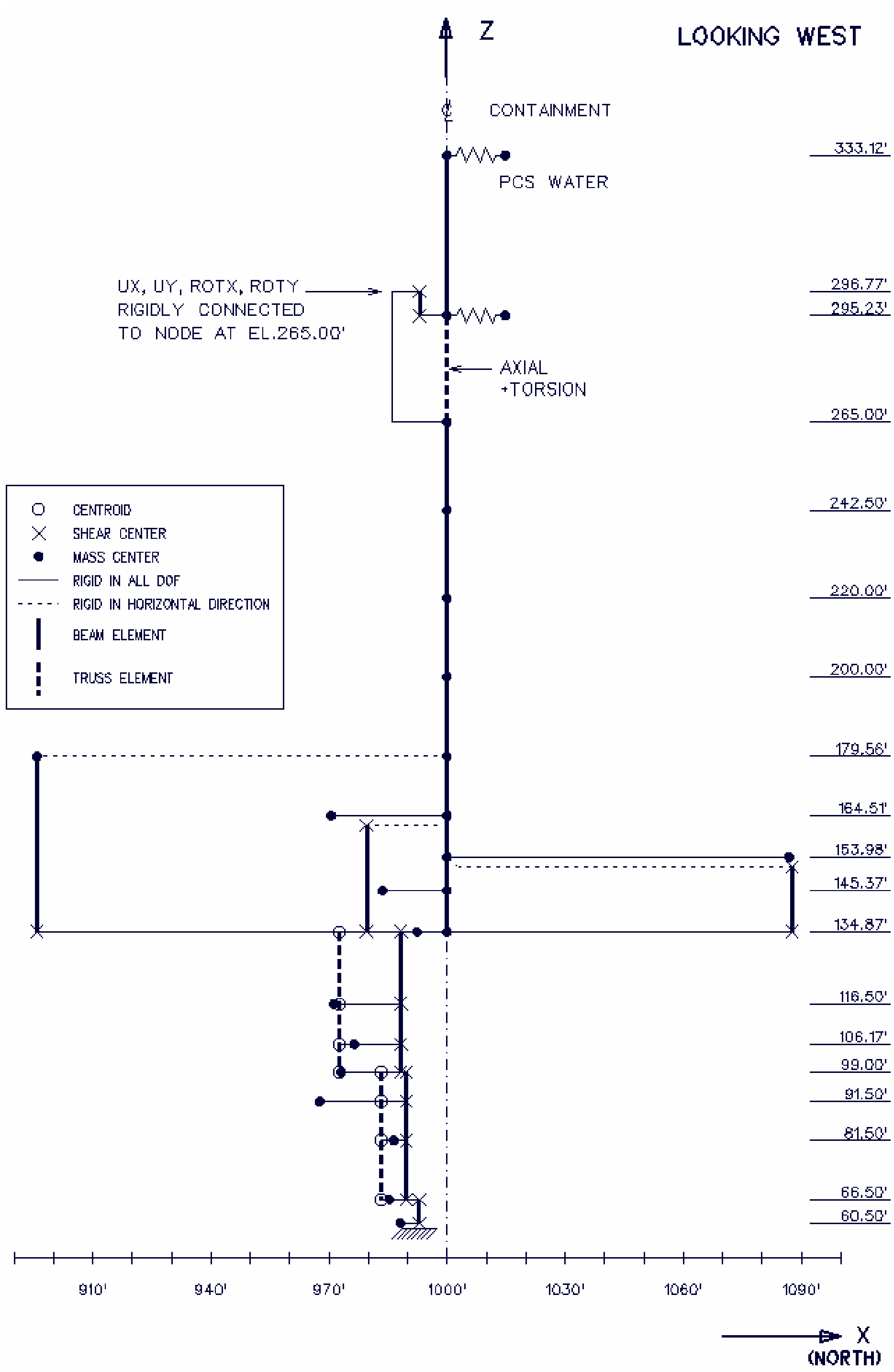


Figure 3.7.2-4 (Sheet 1 of 2)

Coupled Shield & Auxiliary Building Lumped Mass Stick Model (North-South)

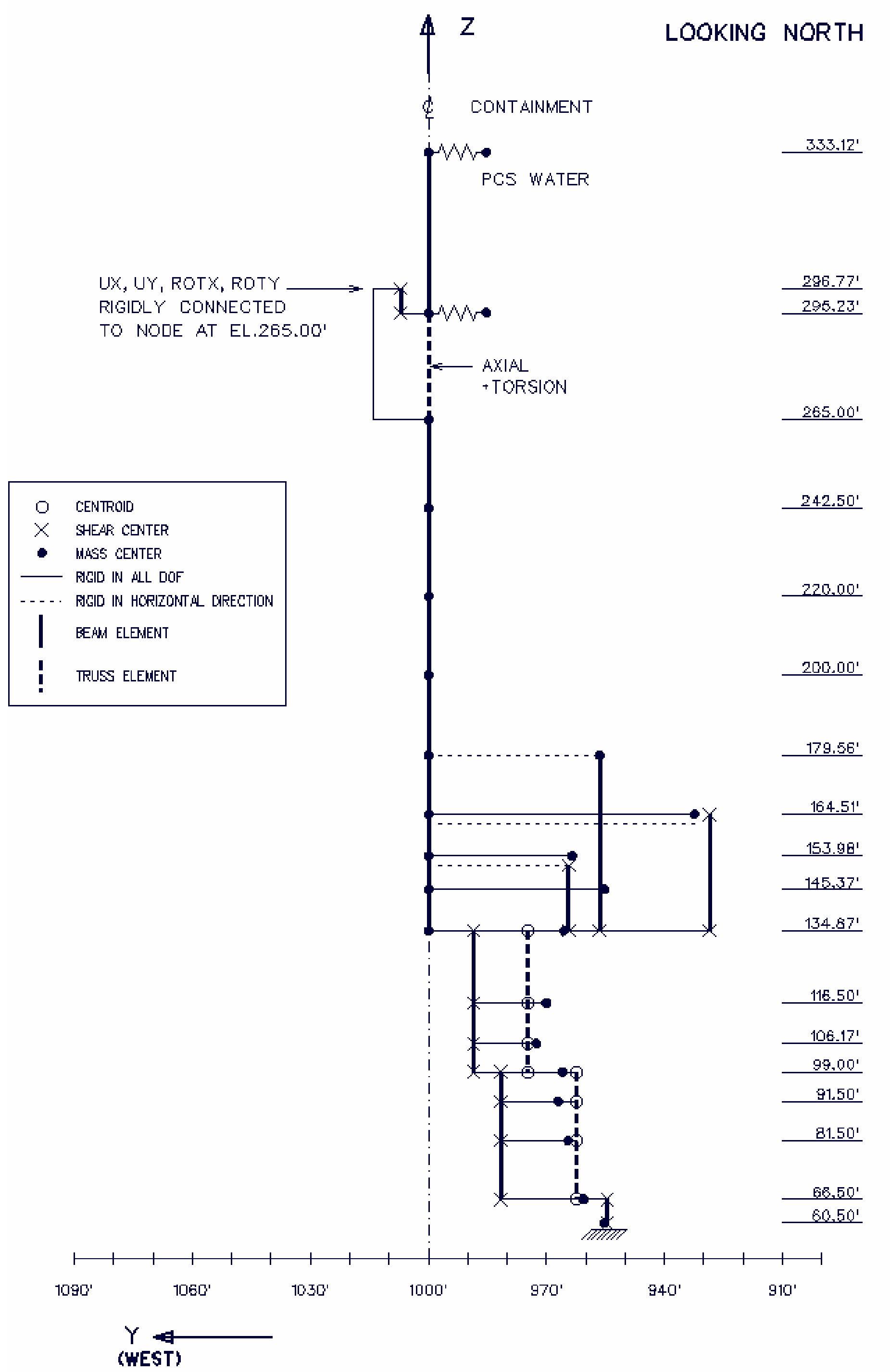


Figure 3.7.2-4 (Sheet 2 of 2)

Coupled Shield & Auxiliary Building Lumped Mass Stick Model (East-West)

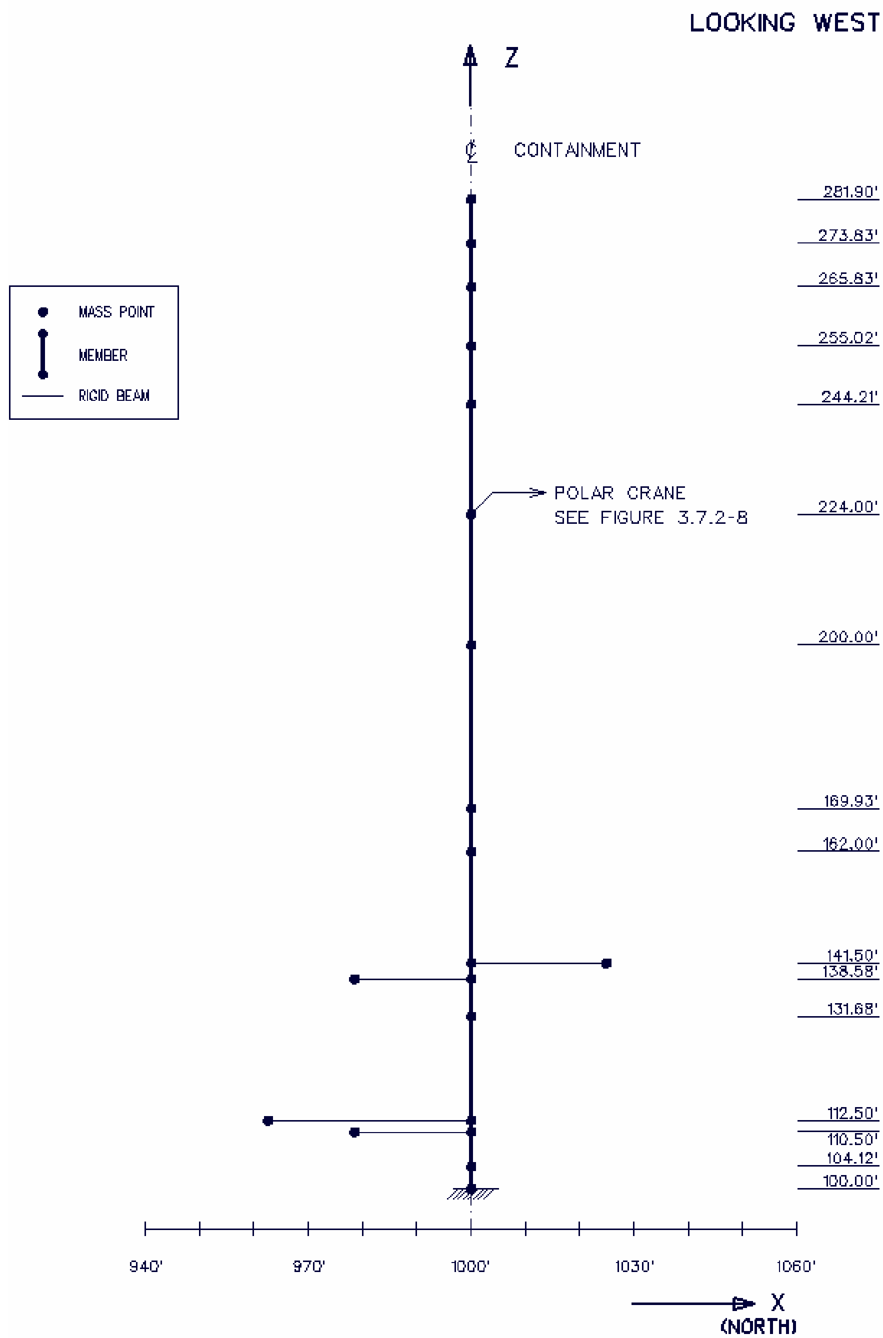


Figure 3.7.2-5

Steel Containment Vessel Lumped Mass Stick Model

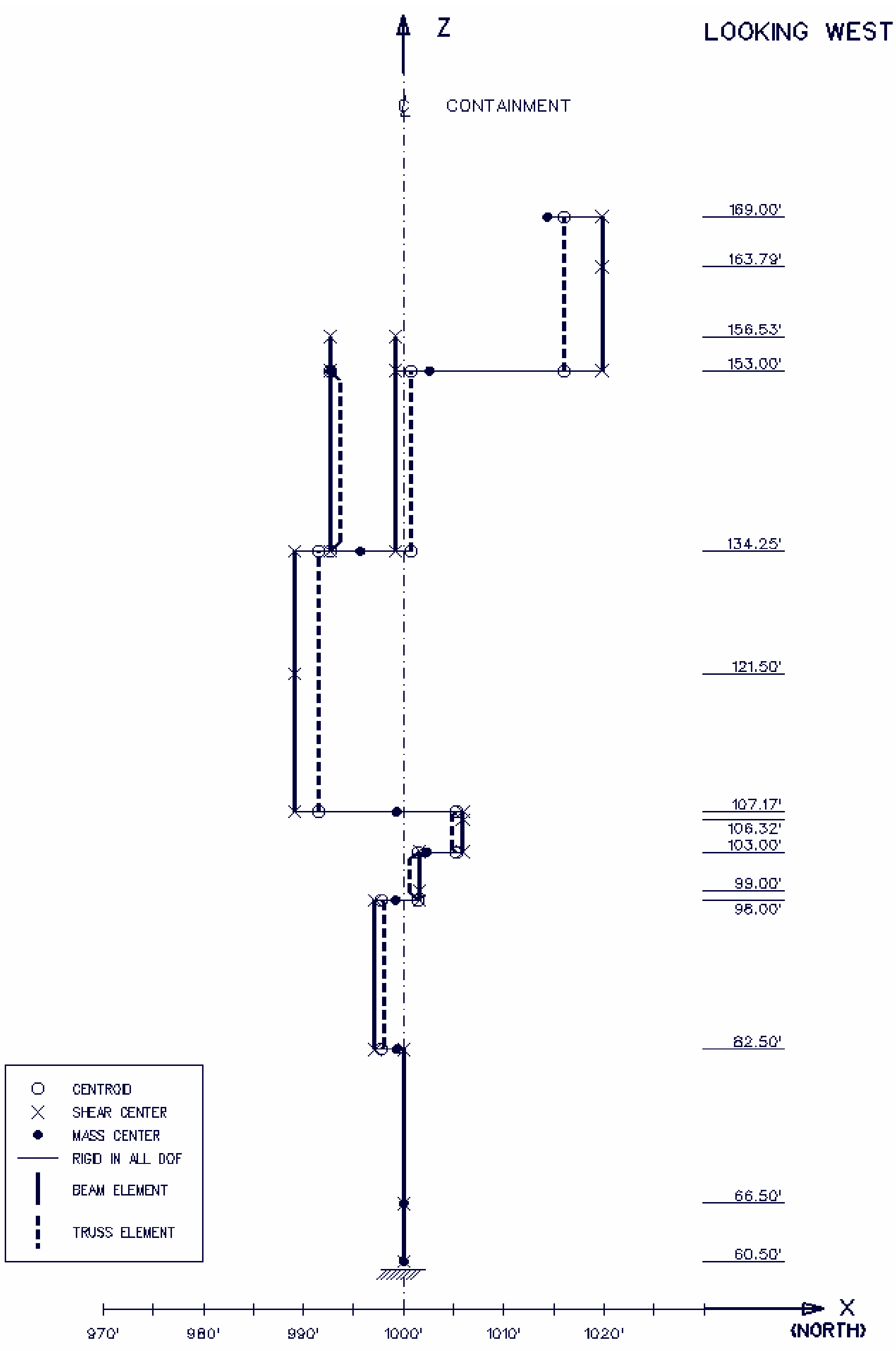


Figure 3.7.2-6 (Sheet 1 of 2)

Containment Internal Structure
Mass Stick Model (North-South)

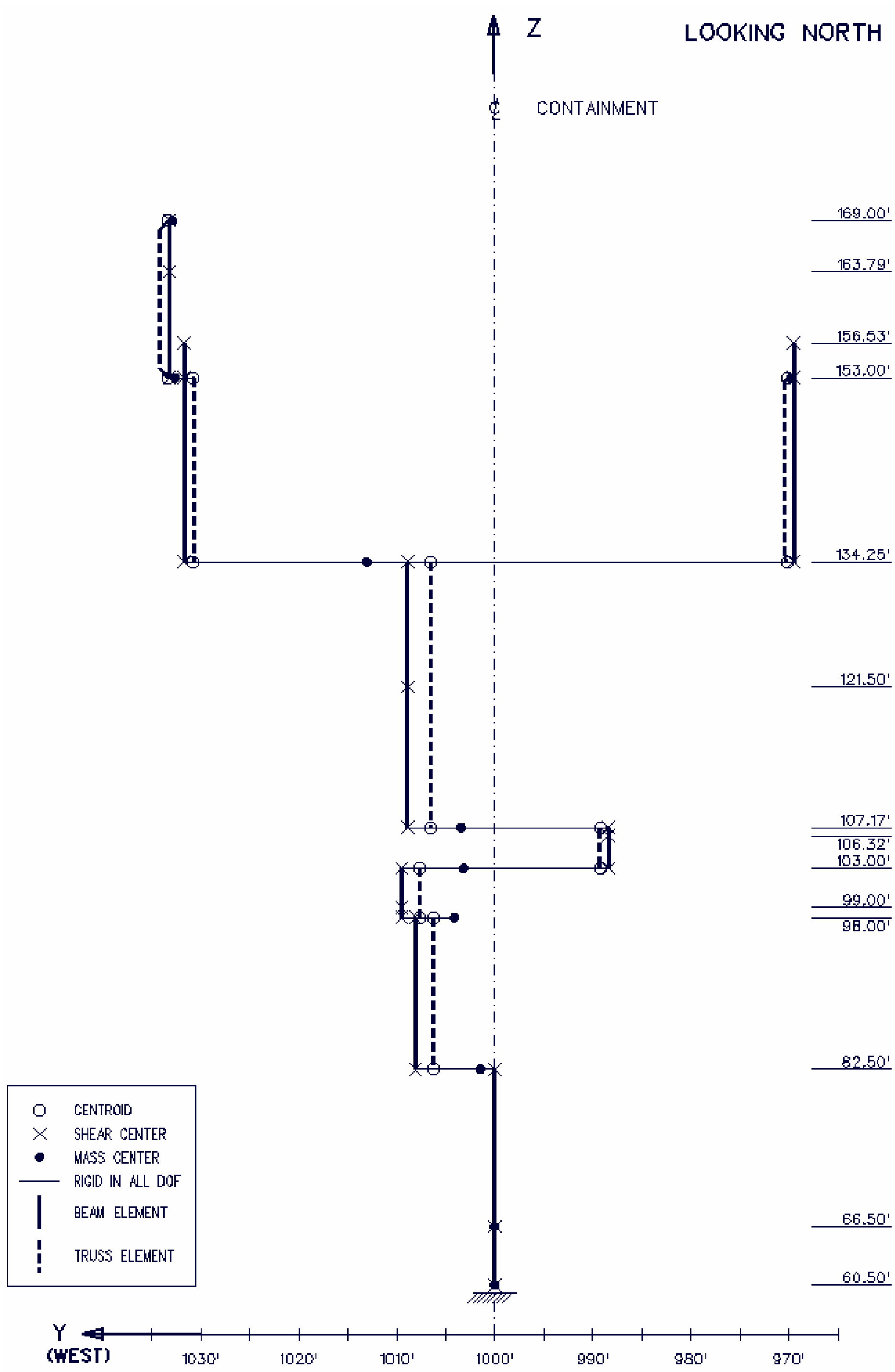


Figure 3.7.2-6 (Sheet 2 of 2)

Containment Internal Structure Mass Stick Model (East-West)

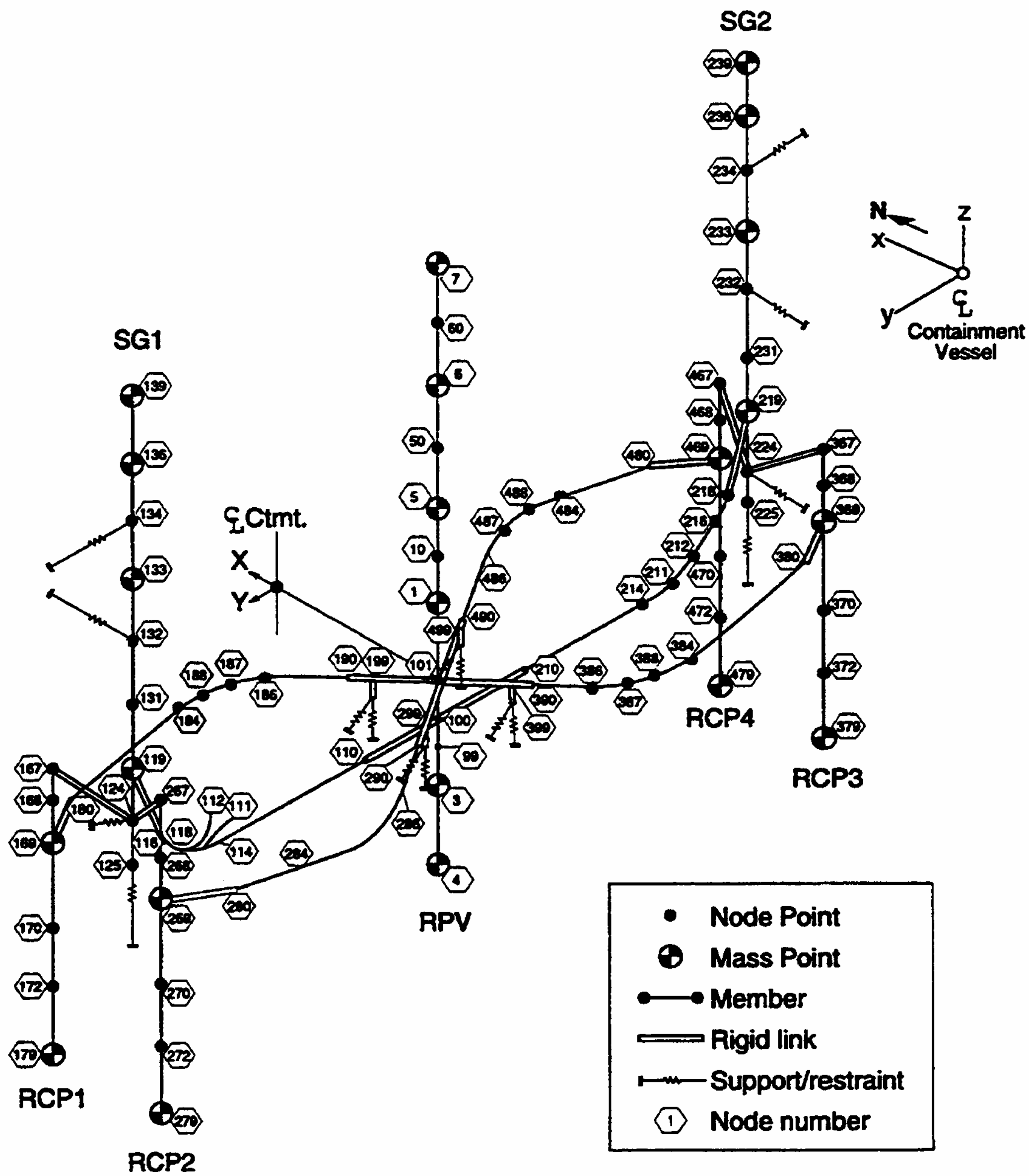
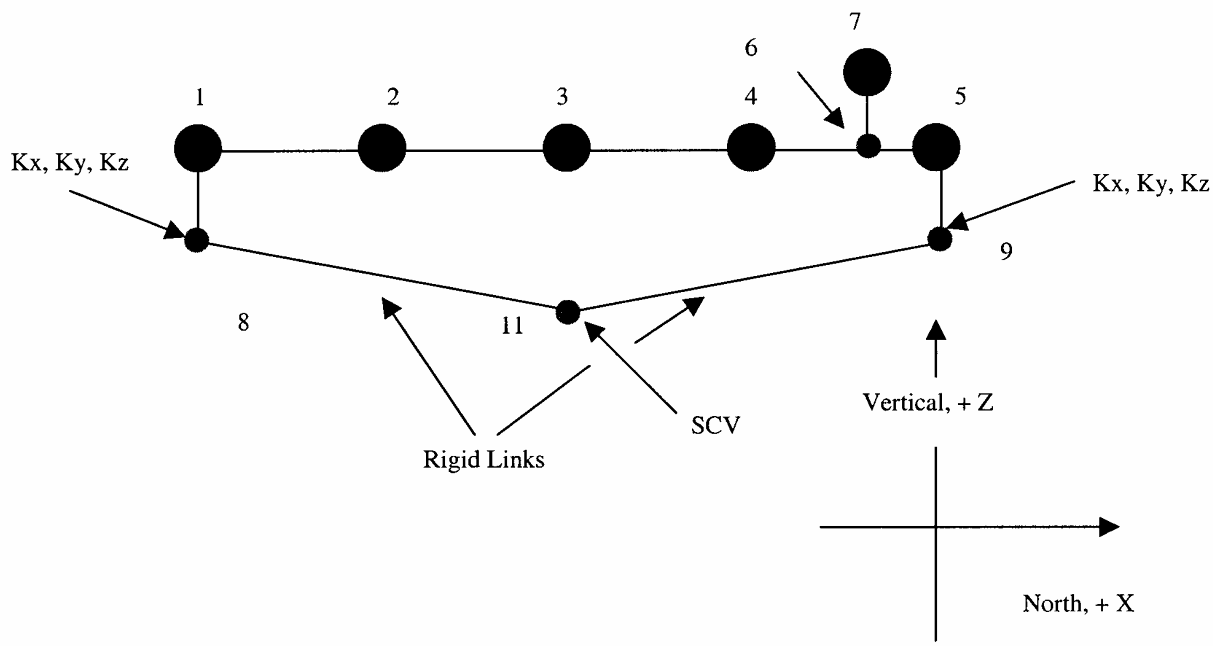


Figure 3.7.2-7

Reactor Coolant Loop
Lumped Mass Stick Model



Local SCV Stiffness are Kx, Ky, Kz

Dynamic Degrees of Freedom

- Masses at nodes 1, 2, 3, 4, 5, and 7
- All Mass nodes have DOFs in X, Y, and Z directions

Comments:

1. Cross Beams between girders are represented by rotation spring constants Kxx and Kzz
2. Cross Beam rotational spring constant Kyy is negligible compared to girder stiffness

Figure 3.7.2-8

Polar Crane Model

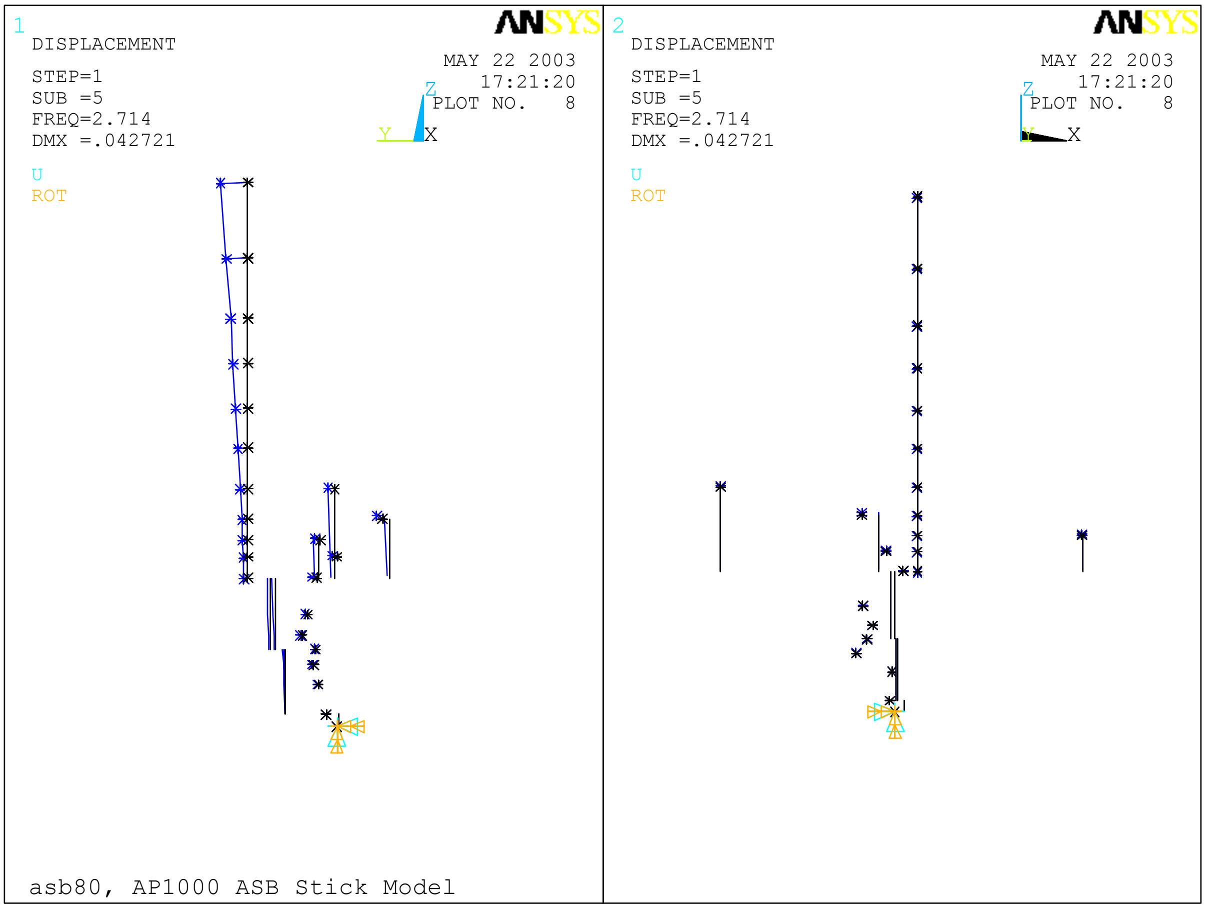


Figure 3.7.2-9 (Sheet 1 of 16)

**Coupled Shield and Auxiliary Buildings
Modeshape Plots**

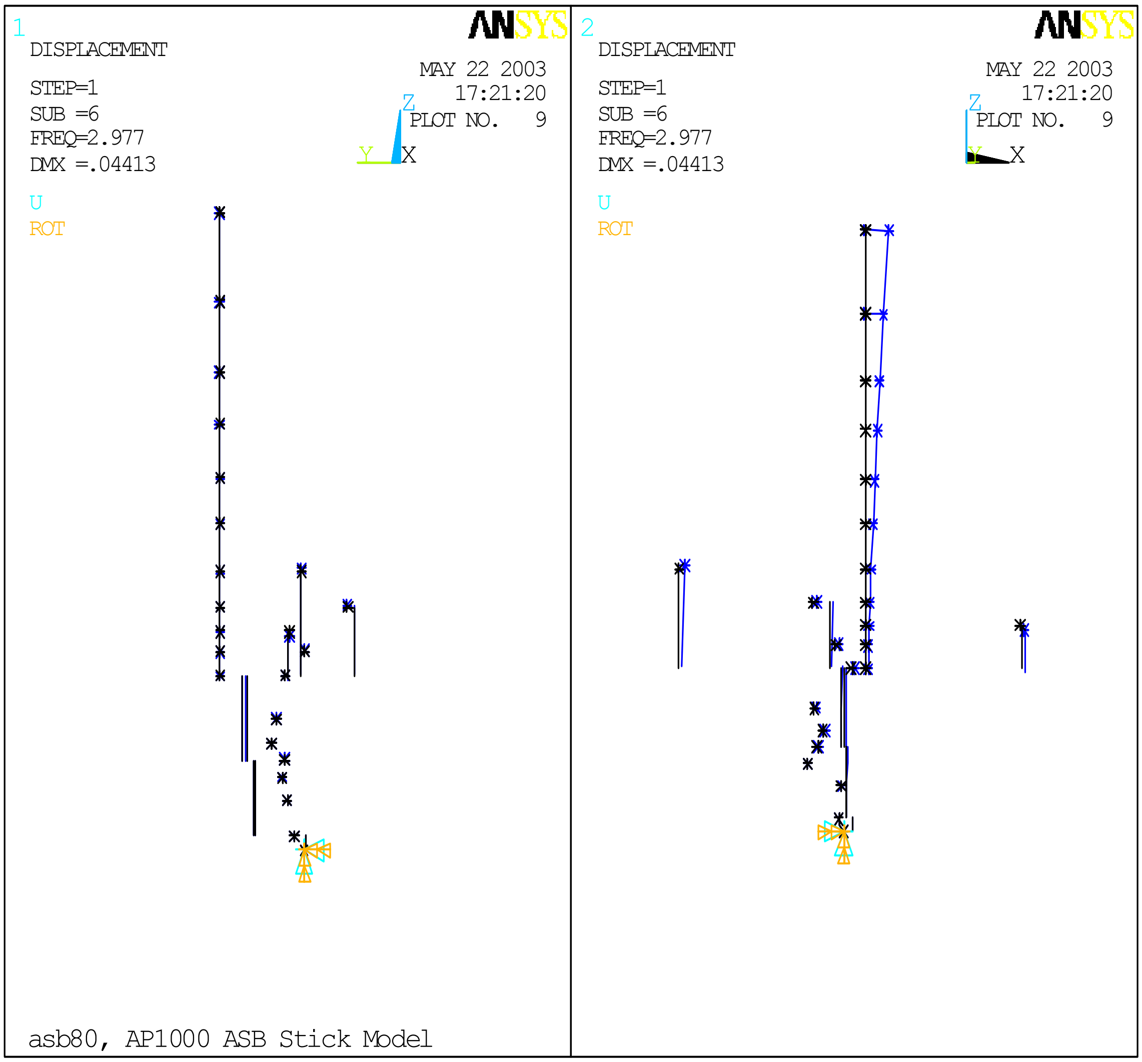


Figure 3.7.2-9 (Sheet 2 of 16)

Coupled Shield and Auxiliary Buildings Modeshape Plots

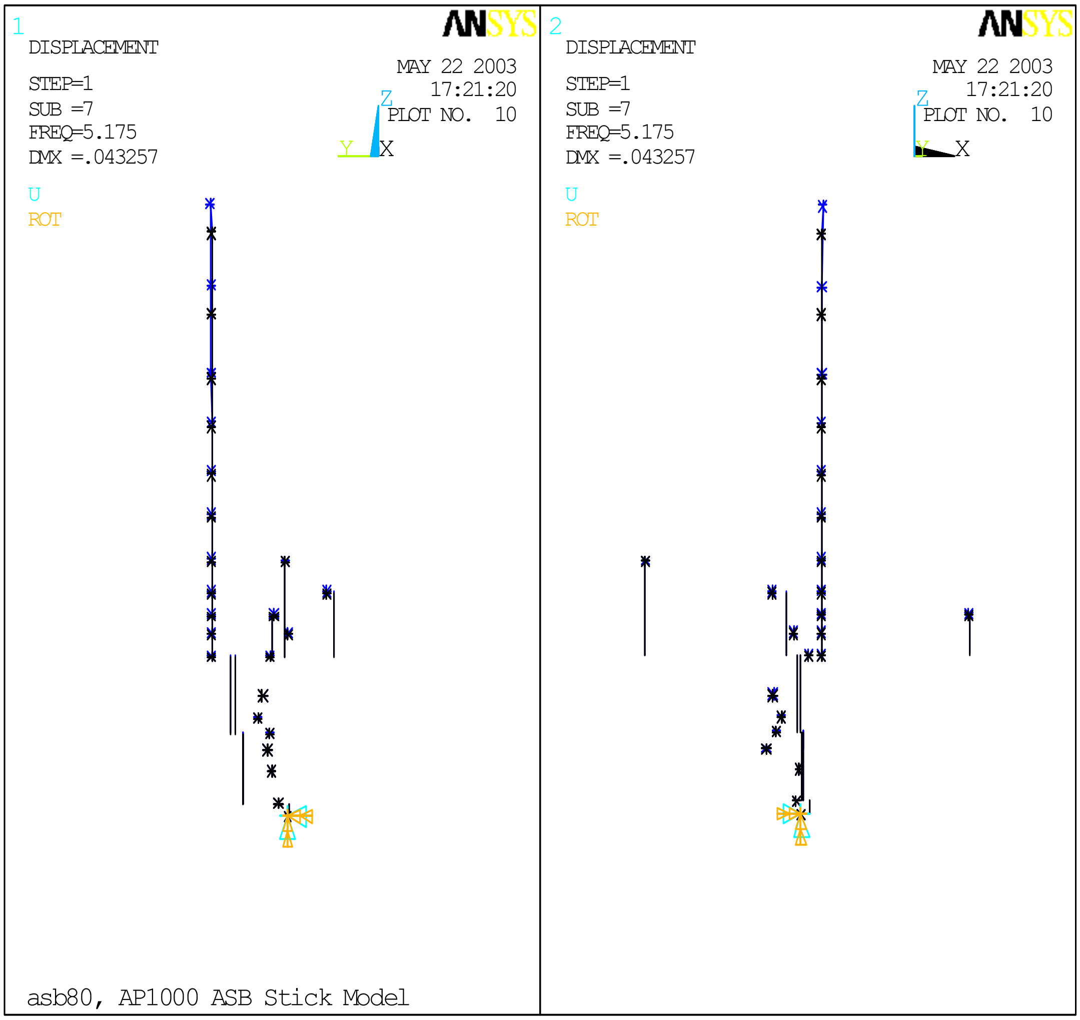


Figure 3.7.2-9 (Sheet 3 of 16)

Coupled Shield and Auxiliary Buildings Modeshape Plots

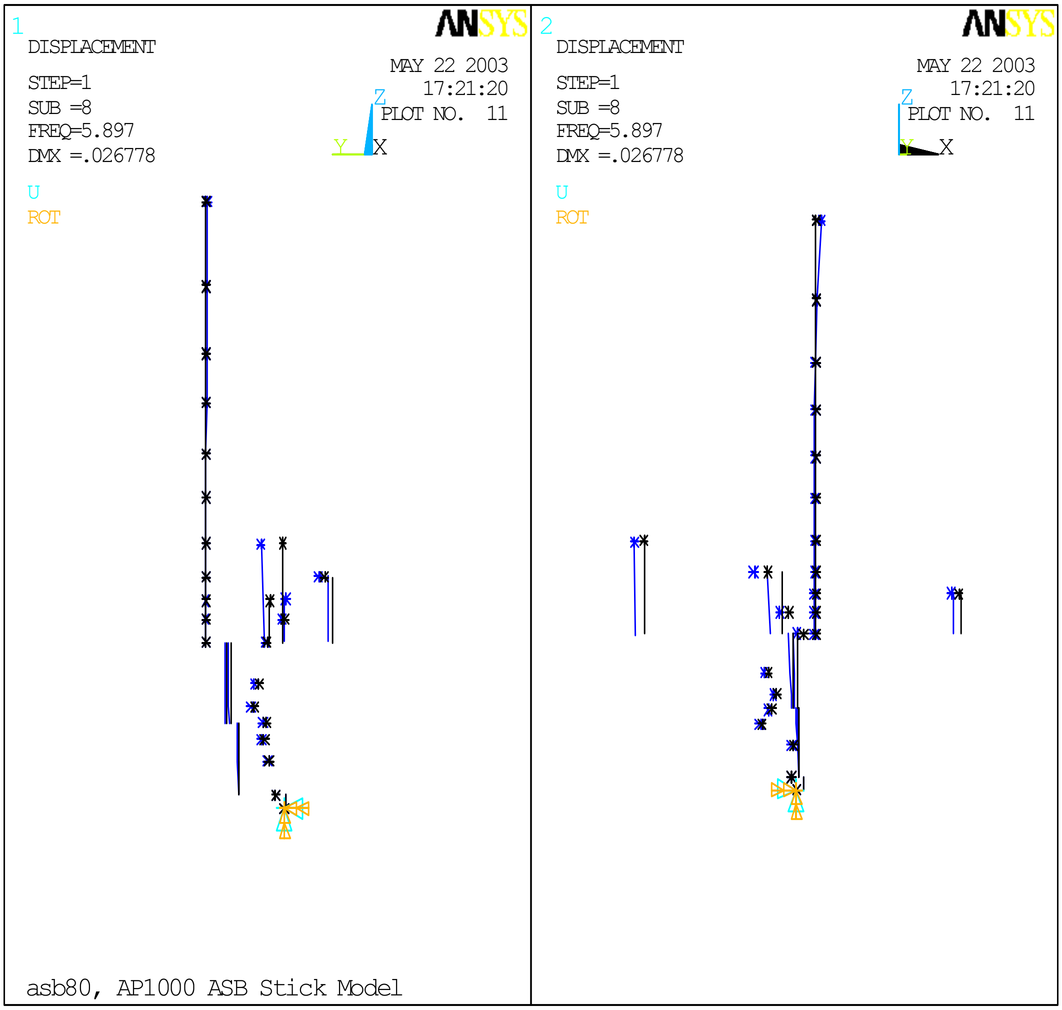


Figure 3.7.2-9 (Sheet 4 of 16)

Coupled Shield and Auxiliary Buildings Modeshape Plots

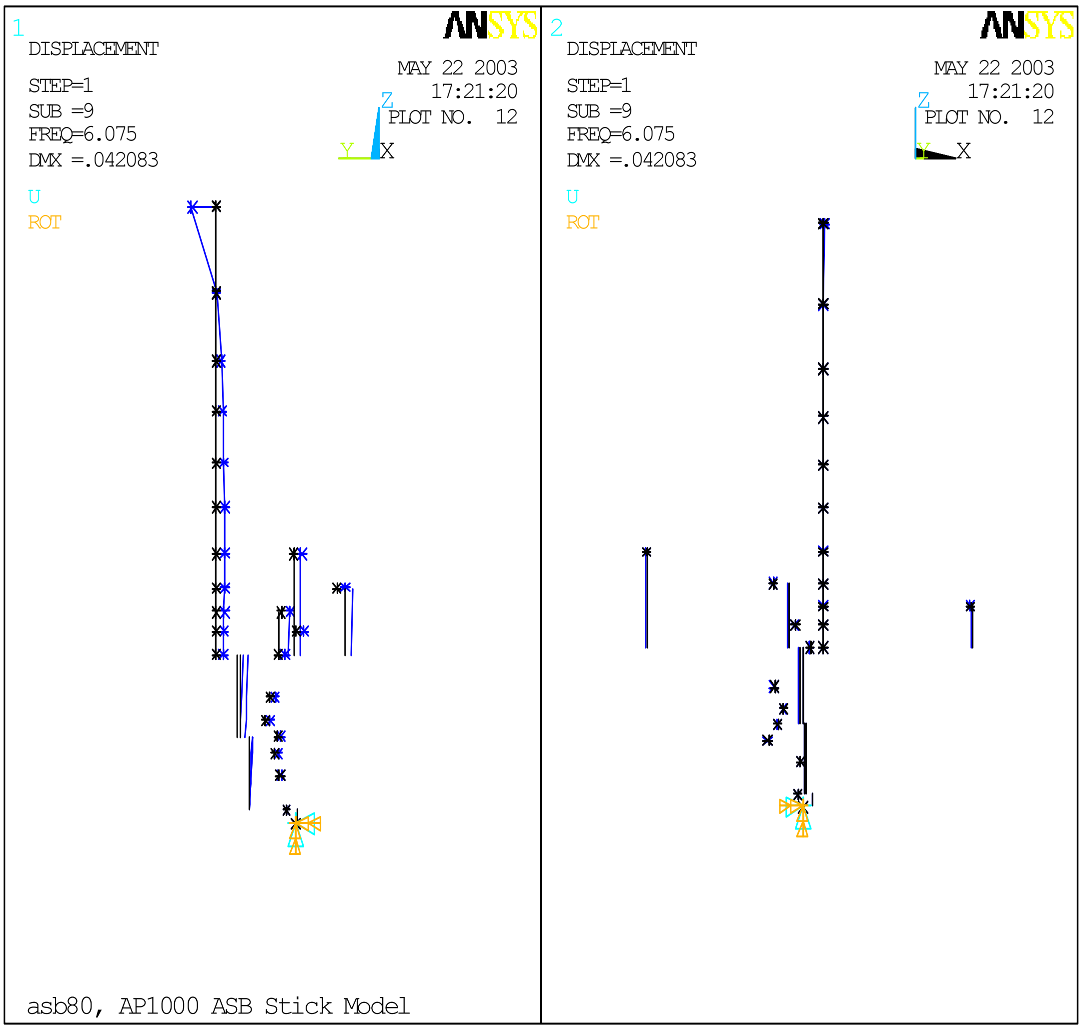


Figure 3.7.2-9 (Sheet 5 of 16)

Coupled Shield and Auxiliary Buildings Modeshape Plots

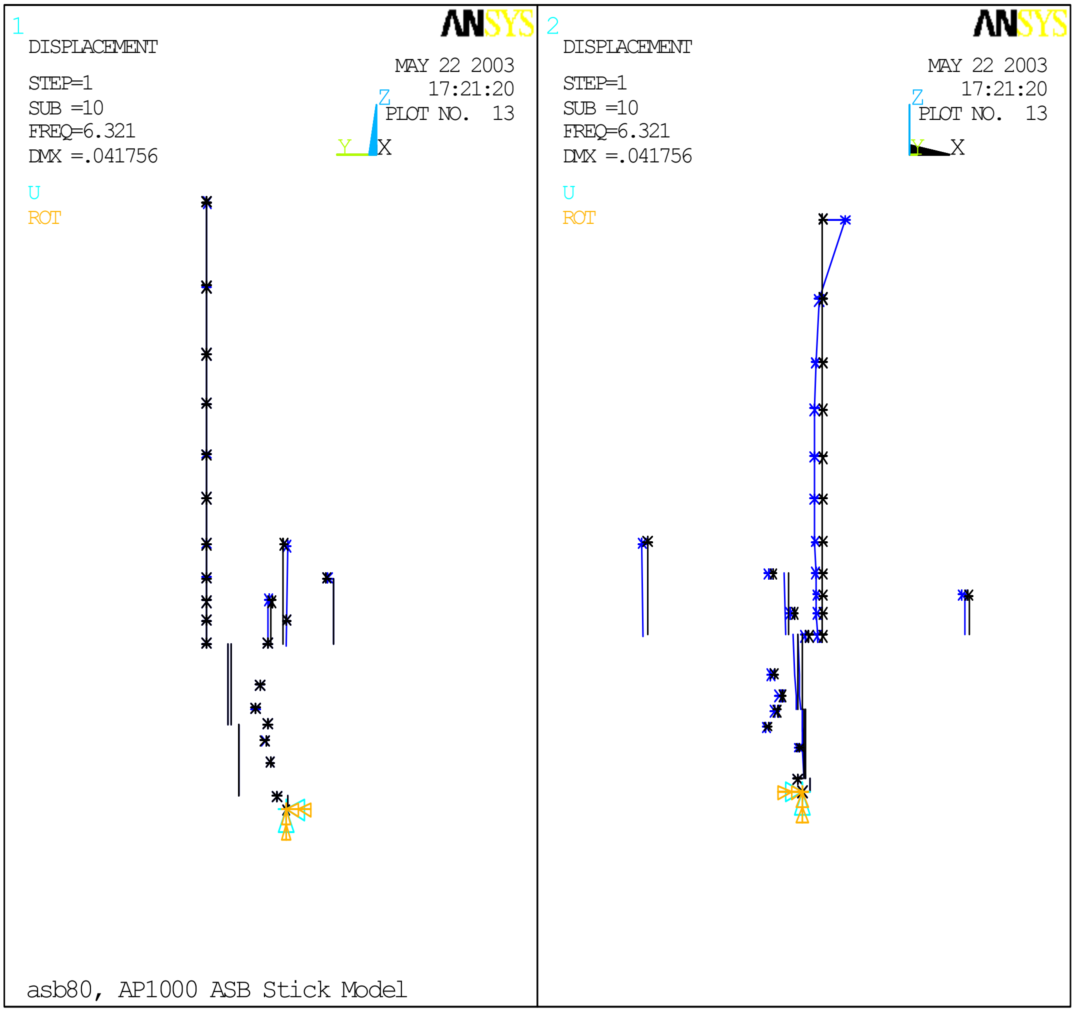


Figure 3.7.2-9 (Sheet 6 of 16)

Coupled Shield and Auxiliary Buildings Modeshape Plots

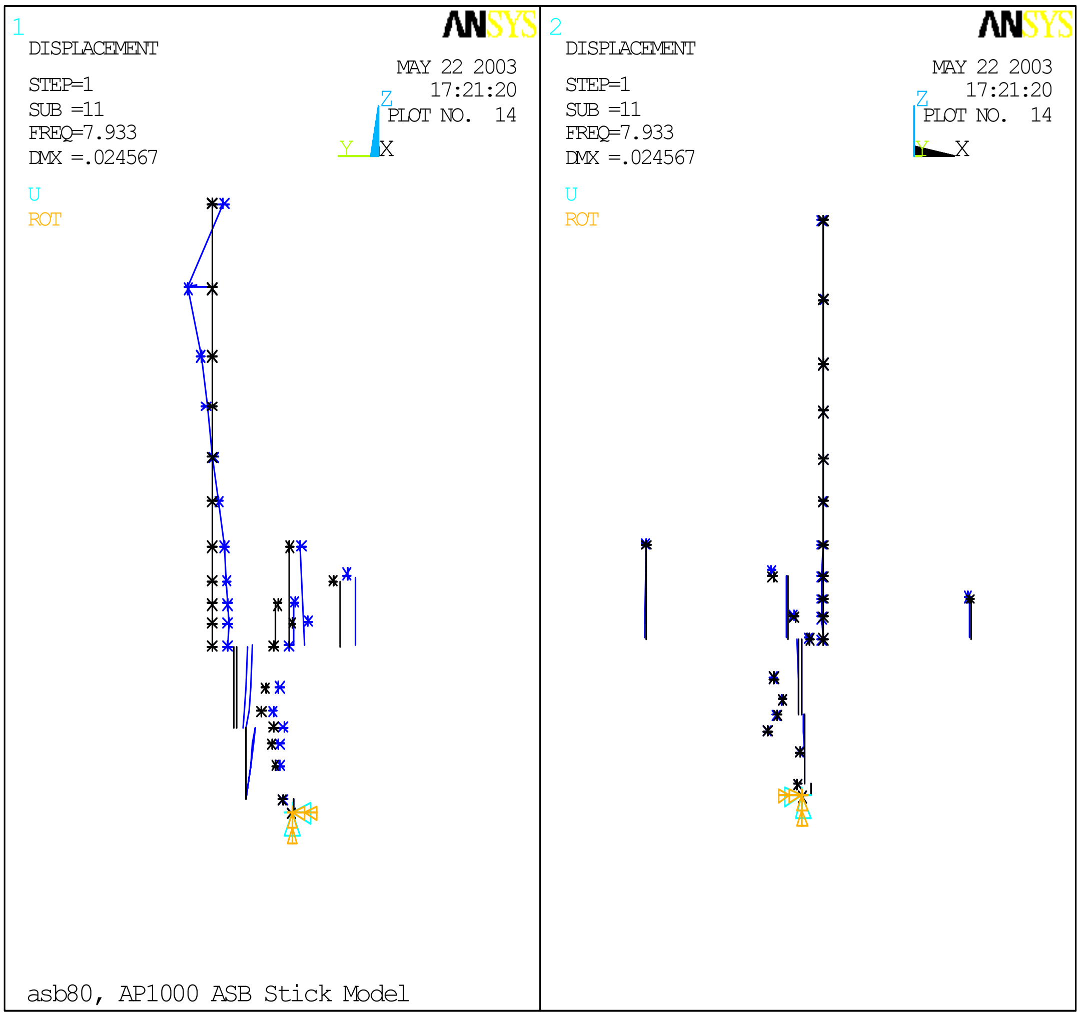


Figure 3.7.2-9 (Sheet 7 of 16)

Coupled Shield and Auxiliary Buildings Modeshape Plots

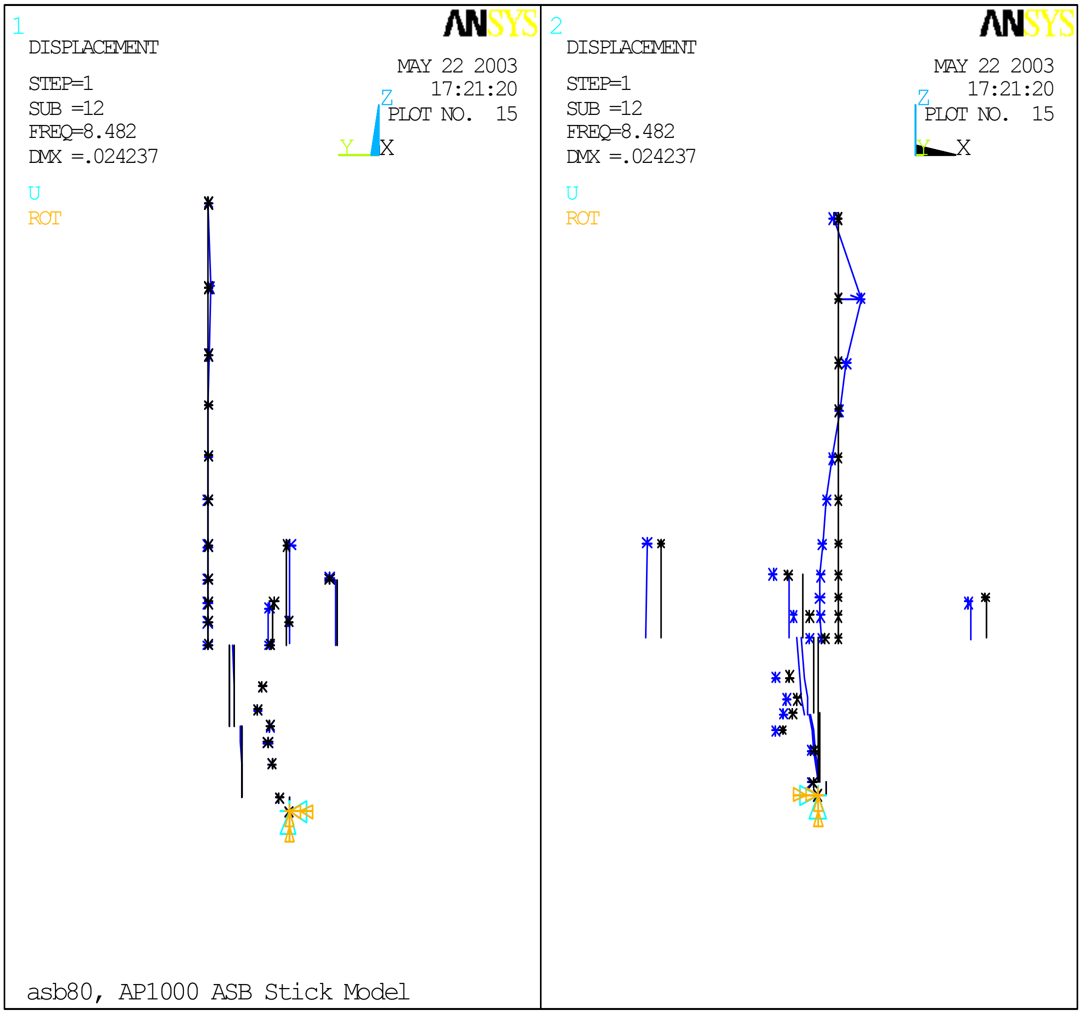


Figure 3.7.2-9 (Sheet 8 of 16)

**Coupled Shield and Auxiliary Buildings
Modeshape Plots**

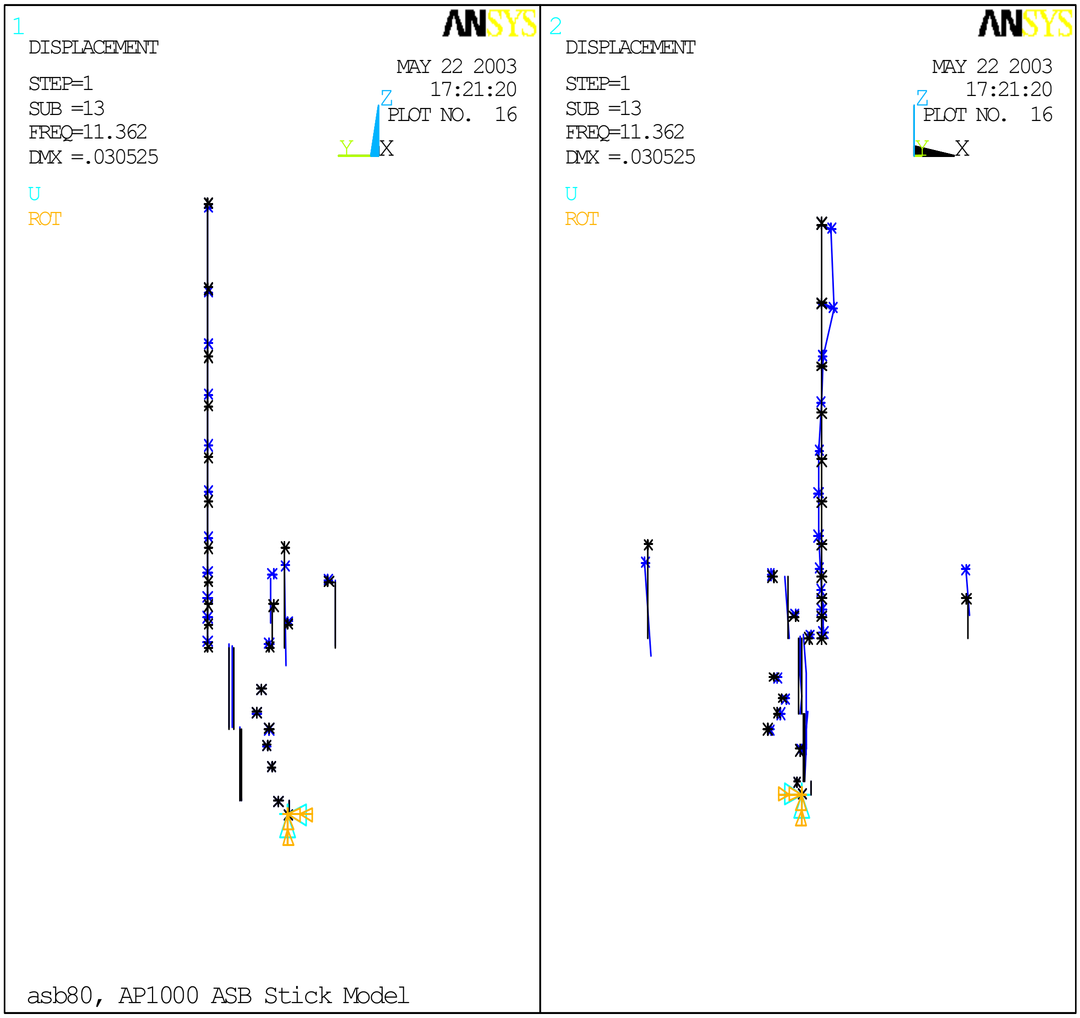


Figure 3.7.2-9 (Sheet 9 of 16)

**Coupled Shield and Auxiliary Buildings
Modeshape Plots**

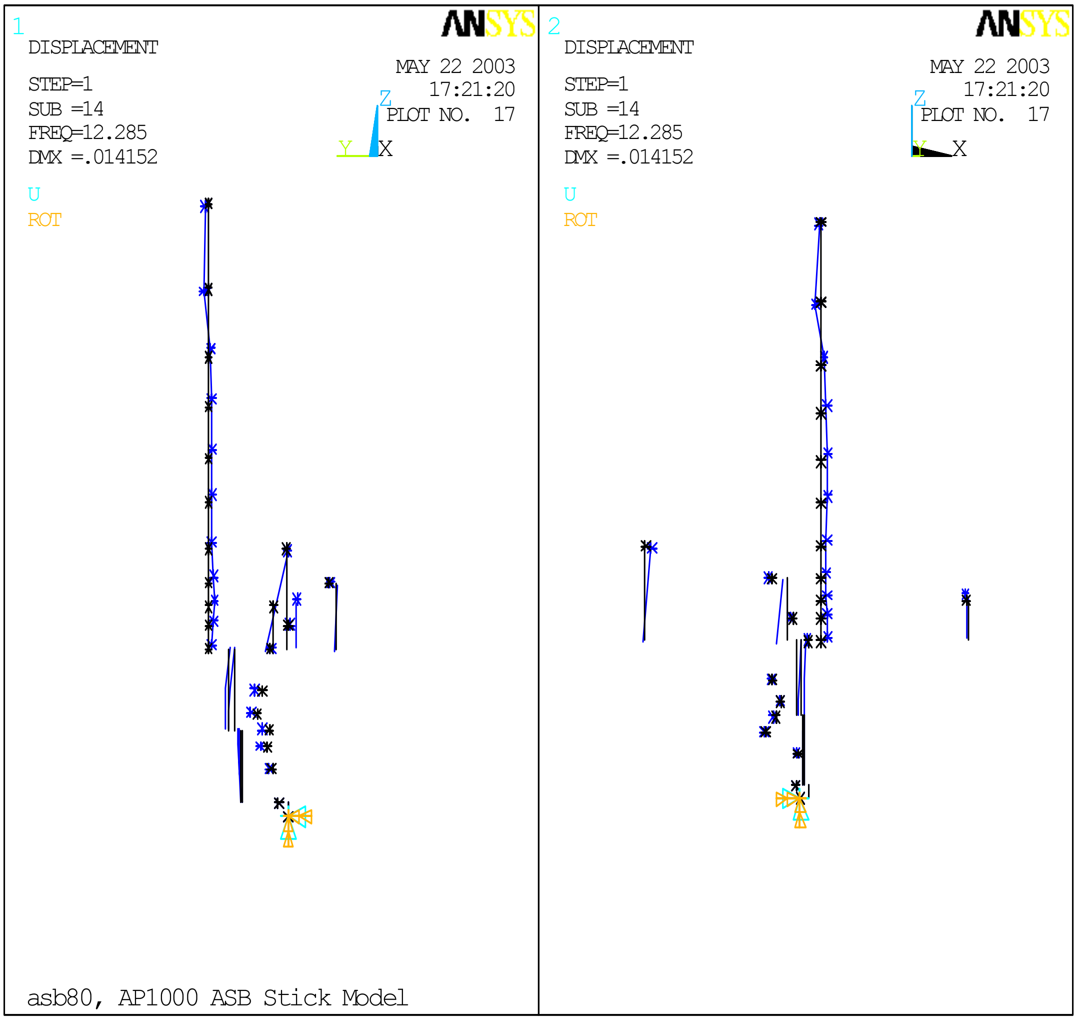


Figure 3.7.2-9 (Sheet 10 of 16)

Coupled Shield and Auxiliary Buildings Modeshape Plots

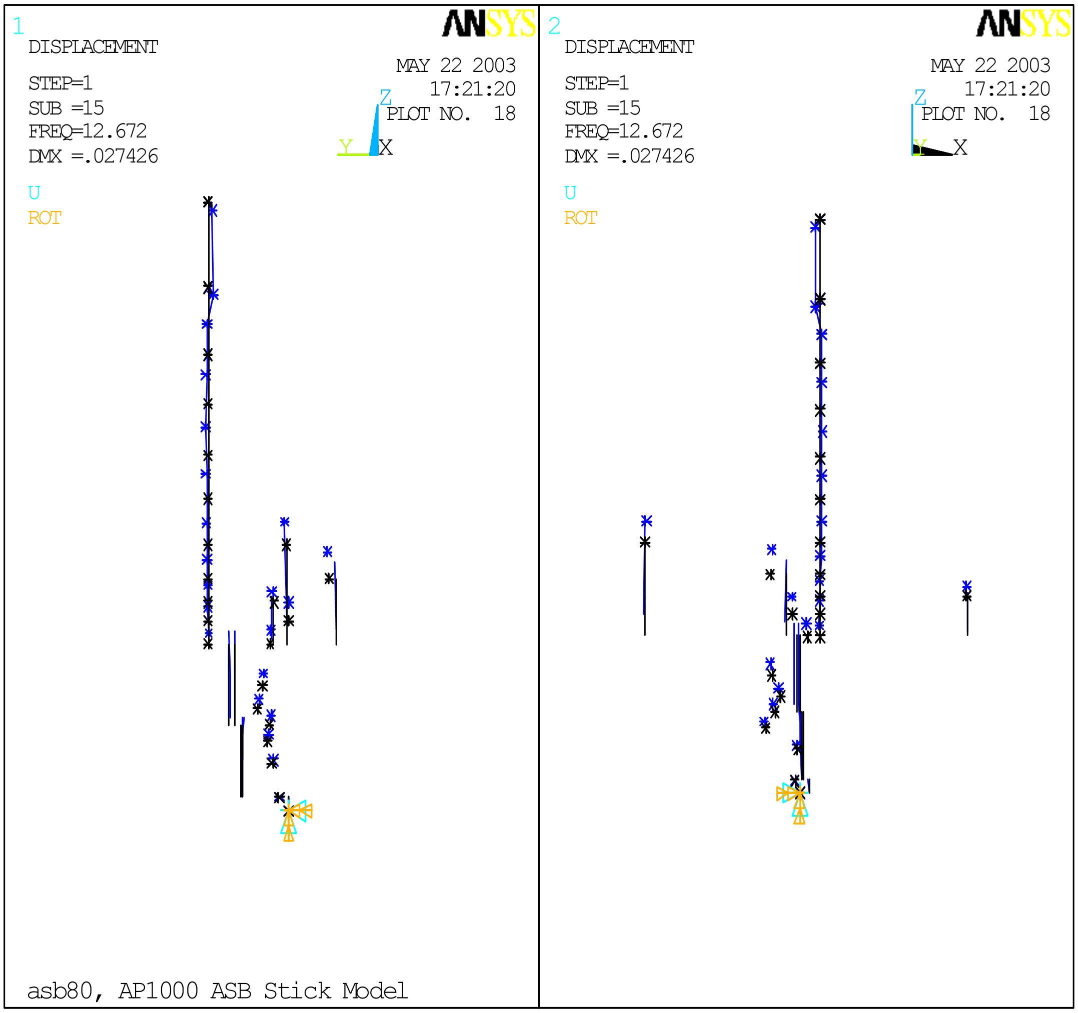


Figure 3.7.2-9 (Sheet 11 of 16)

Coupled Shield and Auxiliary Buildings Modeshape Plots

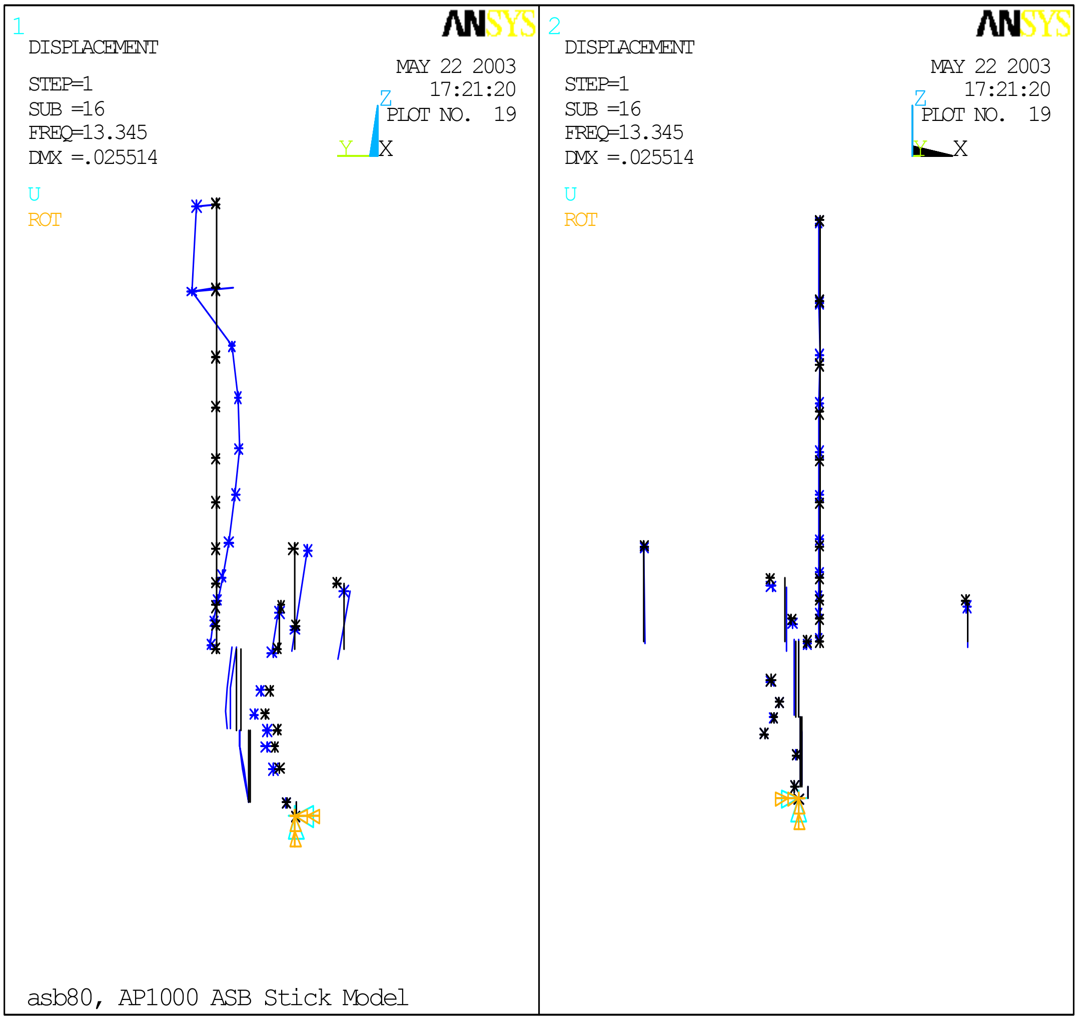


Figure 3.7.2-9 (Sheet 12 of 16)

**Coupled Shield and Auxiliary Buildings
Modeshape Plots**

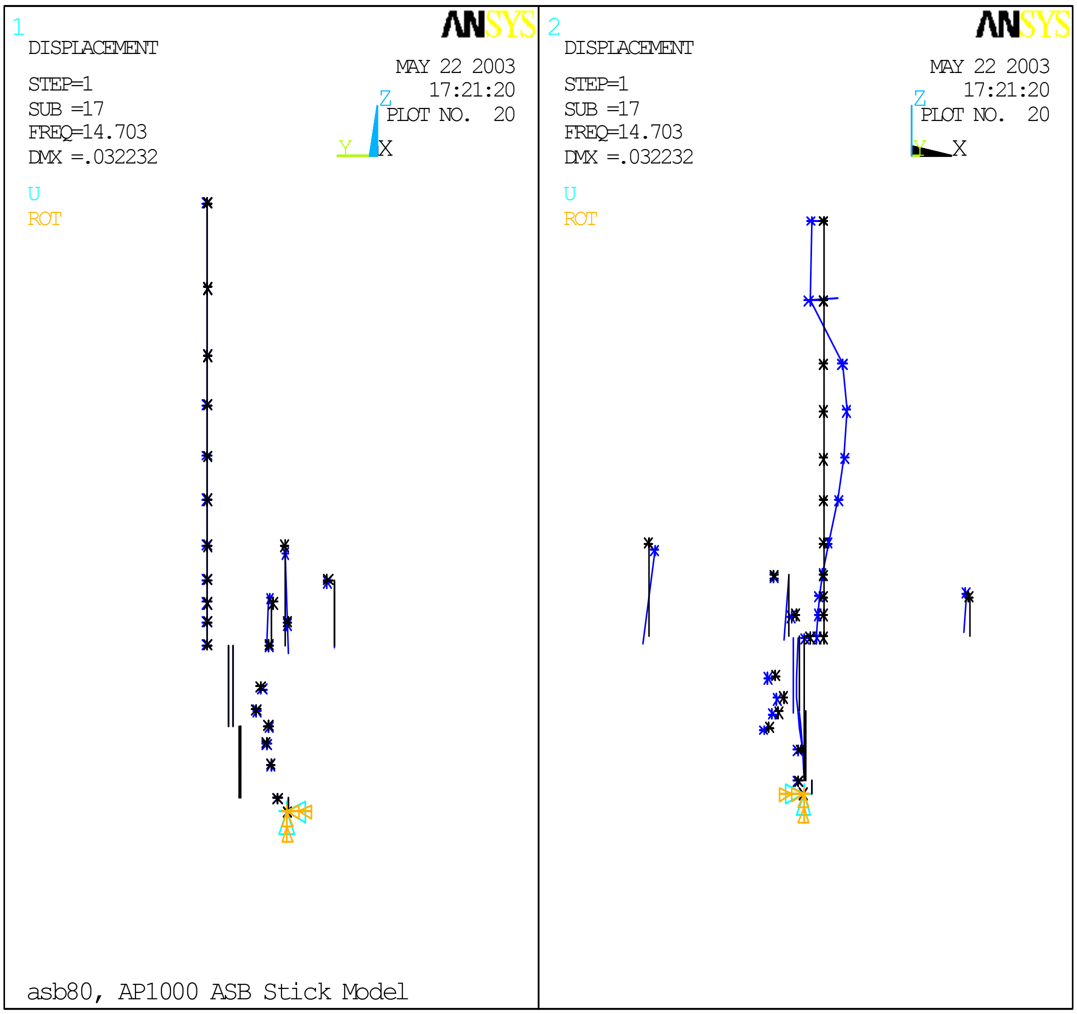


Figure 3.7.2-9 (Sheet 13 of 16)

Coupled Shield and Auxiliary Buildings Modeshape Plots

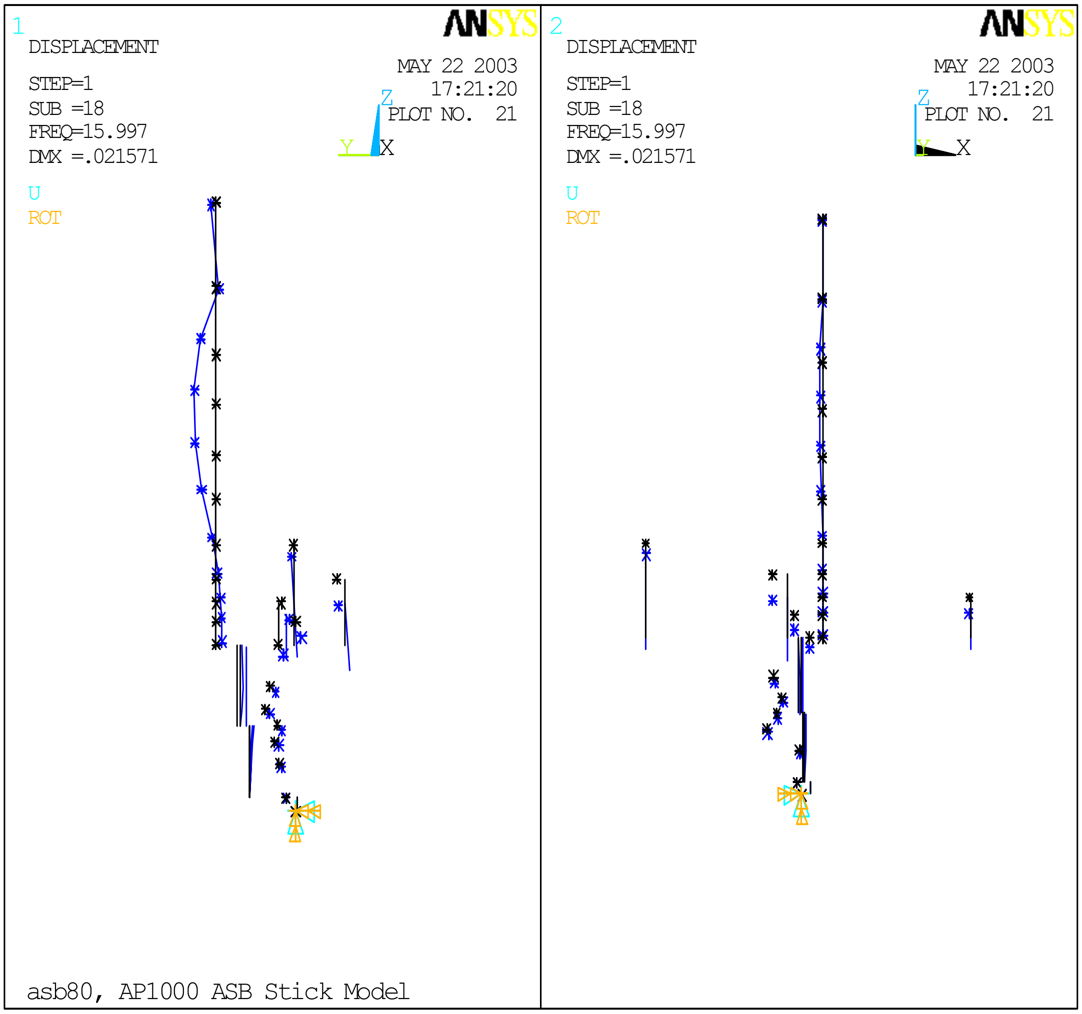


Figure 3.7.2-9 (Sheet 14 of 16)

Coupled Shield and Auxiliary Buildings Modeshape Plots

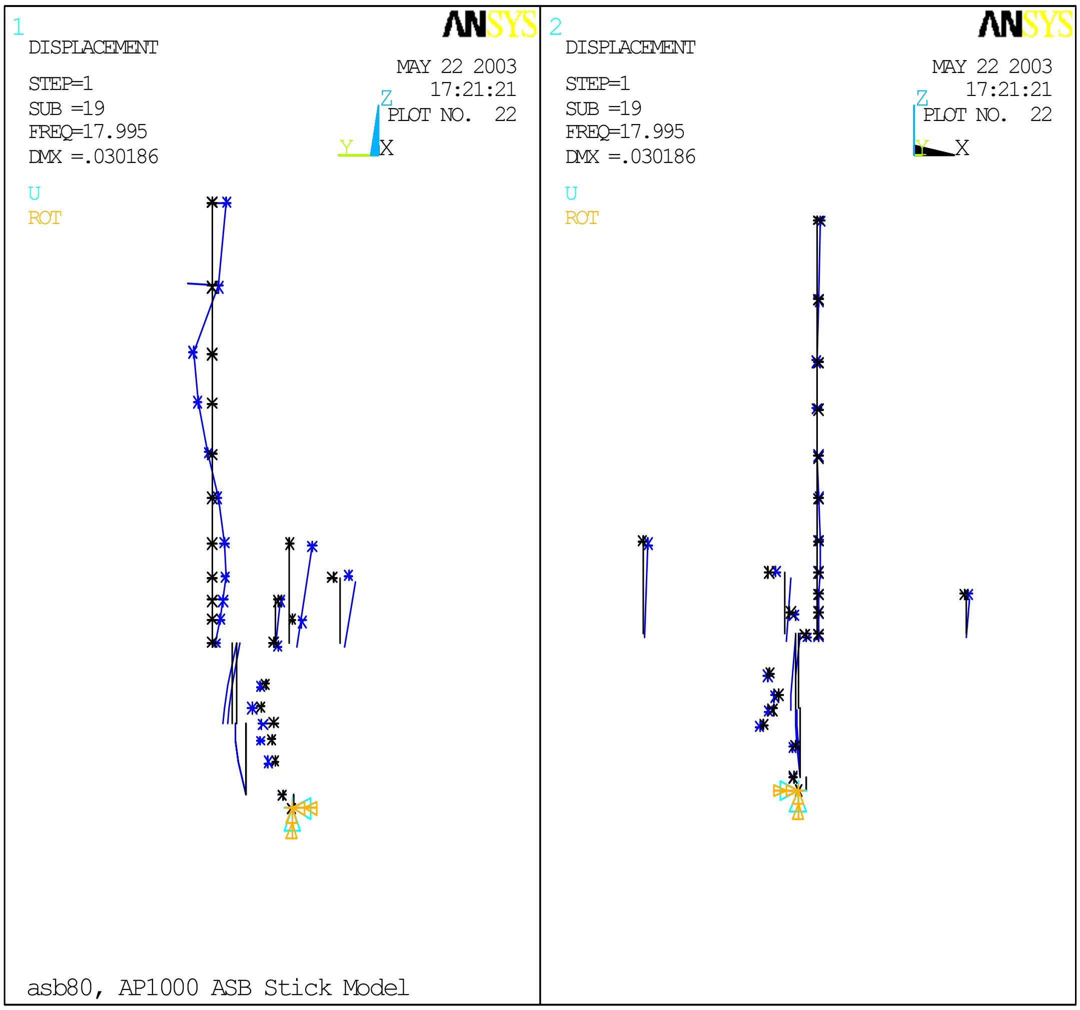


Figure 3.7.2-9 (Sheet 15 of 16)

Coupled Shield and Auxiliary Buildings Modeshape Plots

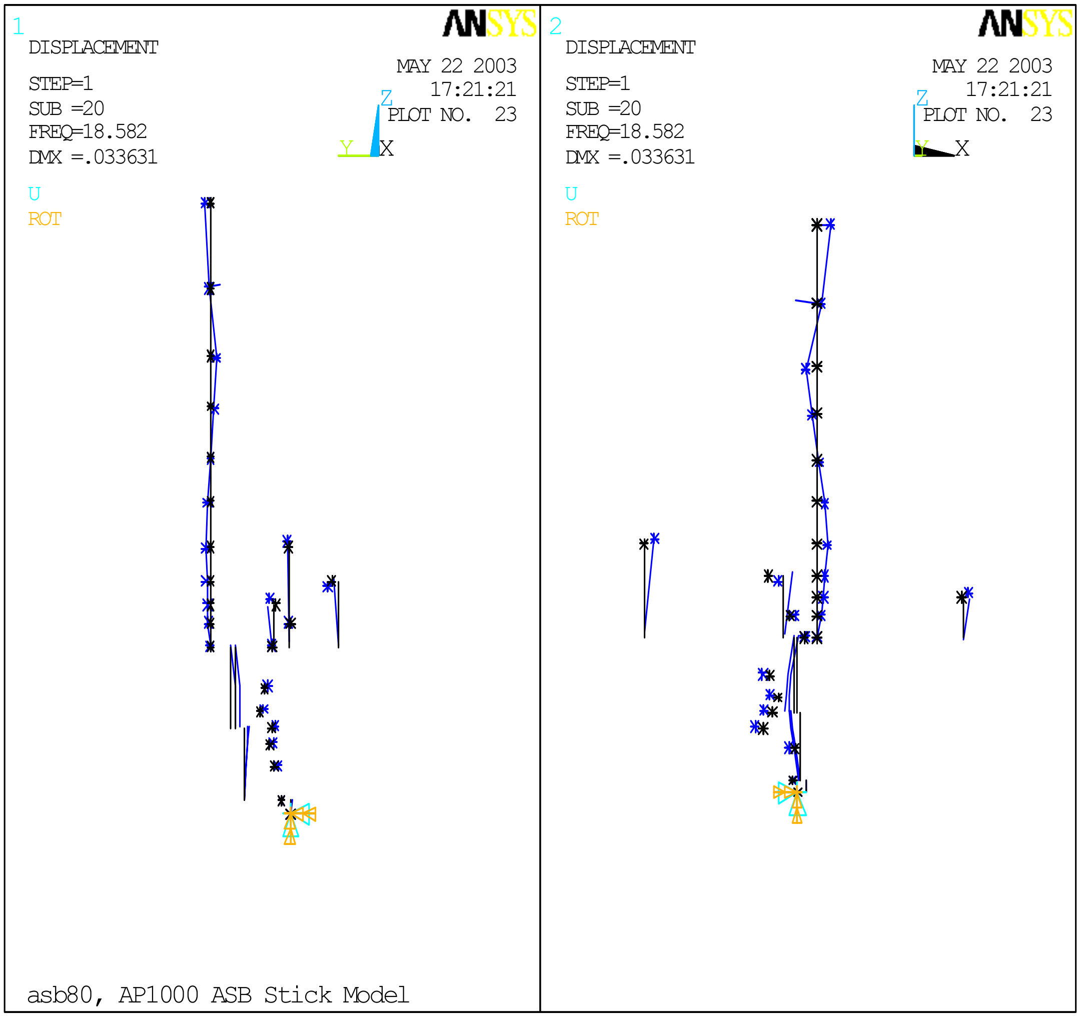
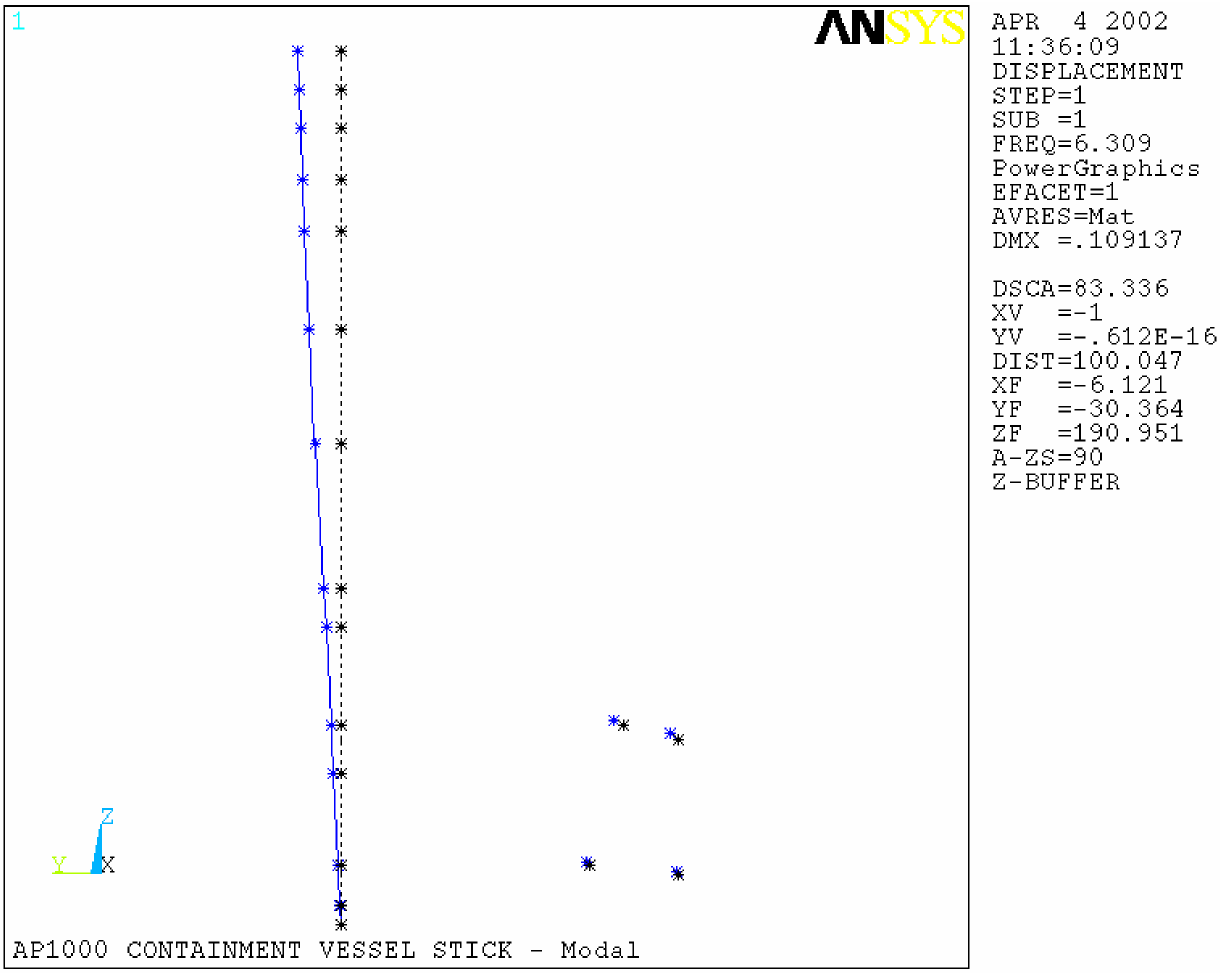


Figure 3.7.2-9 (Sheet 16 of 16)

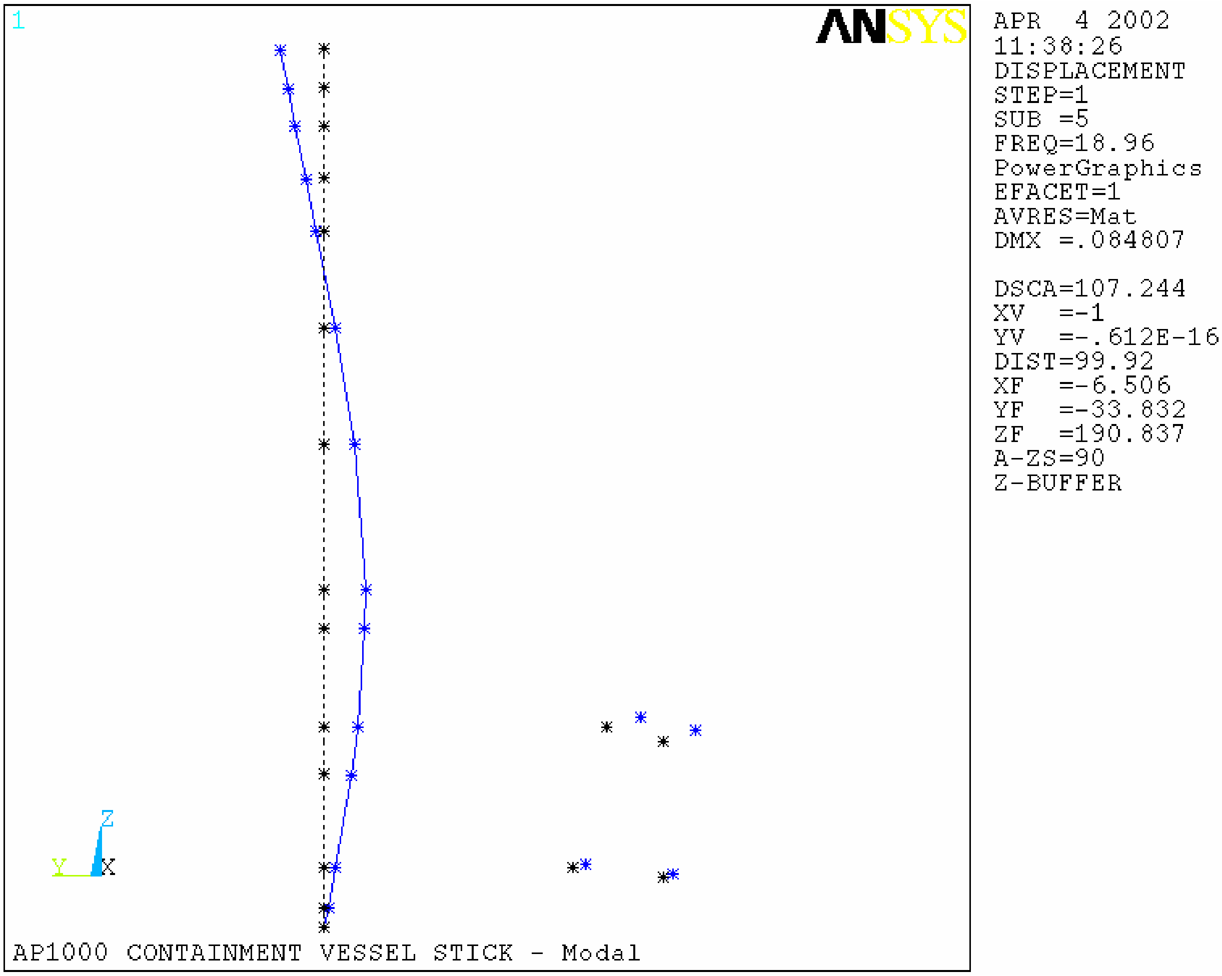
Coupled Shield and Auxiliary Buildings Modeshape Plots



First Horizontal Mode (Y-Direction)

Figure 3.7.2-10 (Sheet 1 of 4)

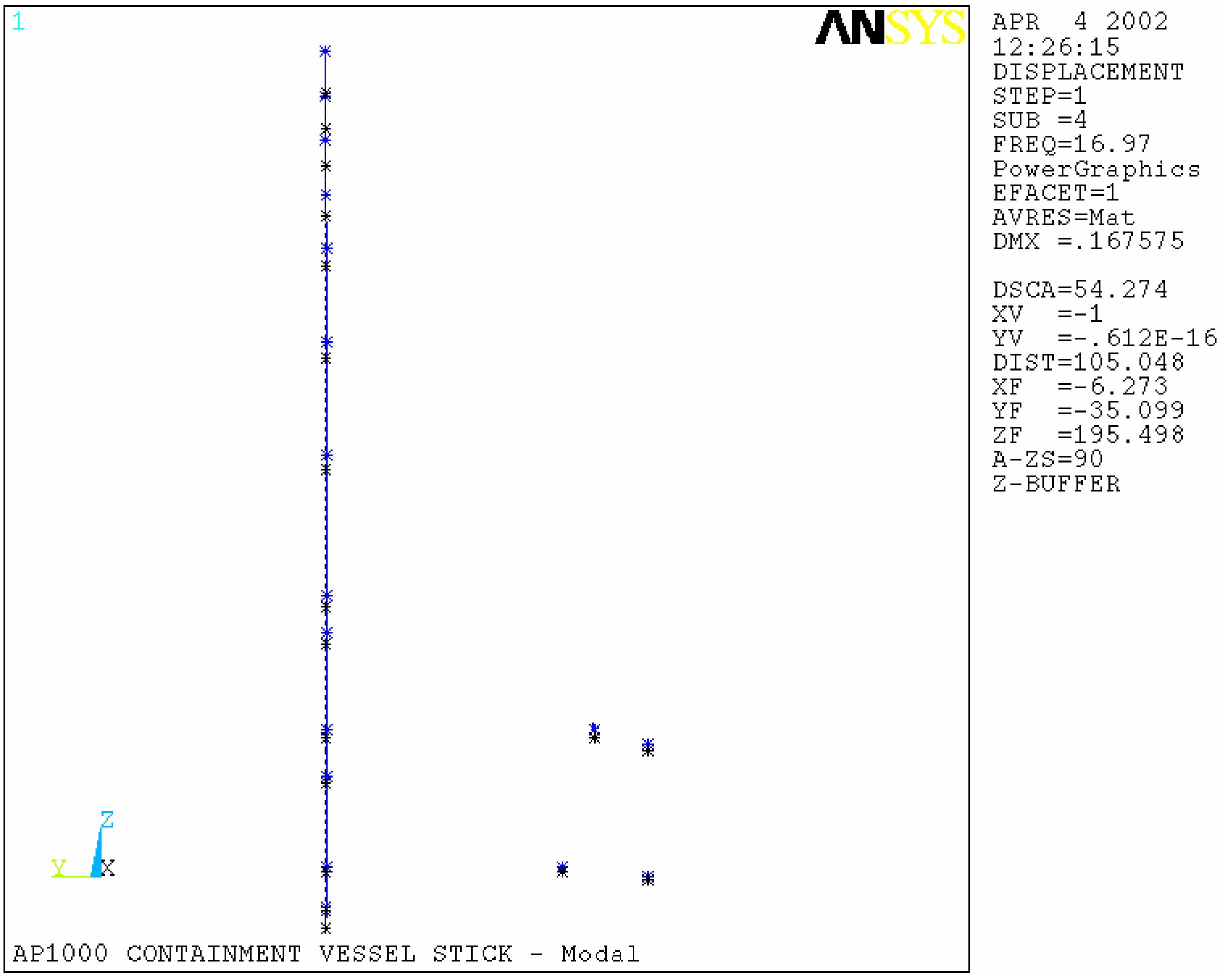
Steel Containment Vessel Modeshape Plots



Second Horizontal Mode Y-Direction

Figure 3.7.2-10 (Sheet 2 of 4)

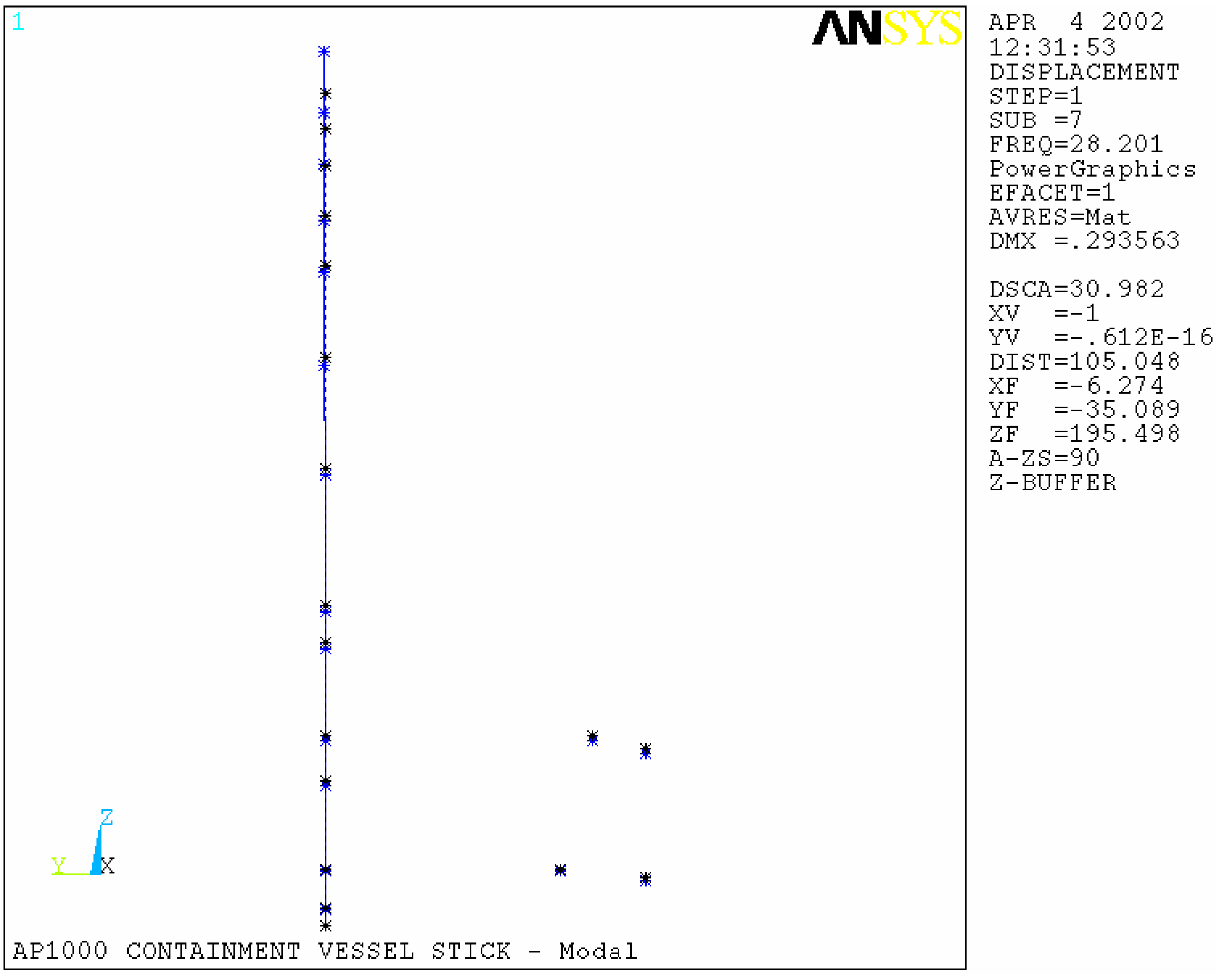
Steel Containment Vessel Modeshape Plots



First Vertical Mode

Figure 3.7.2-10 (Sheet 3 of 4)

Steel Containment Vessel Modeshape Plots



Second Vertical Mode

Figure 3.7.2-10 (Sheet 4 of 4)

Steel Containment Vessel Modeshape Plots

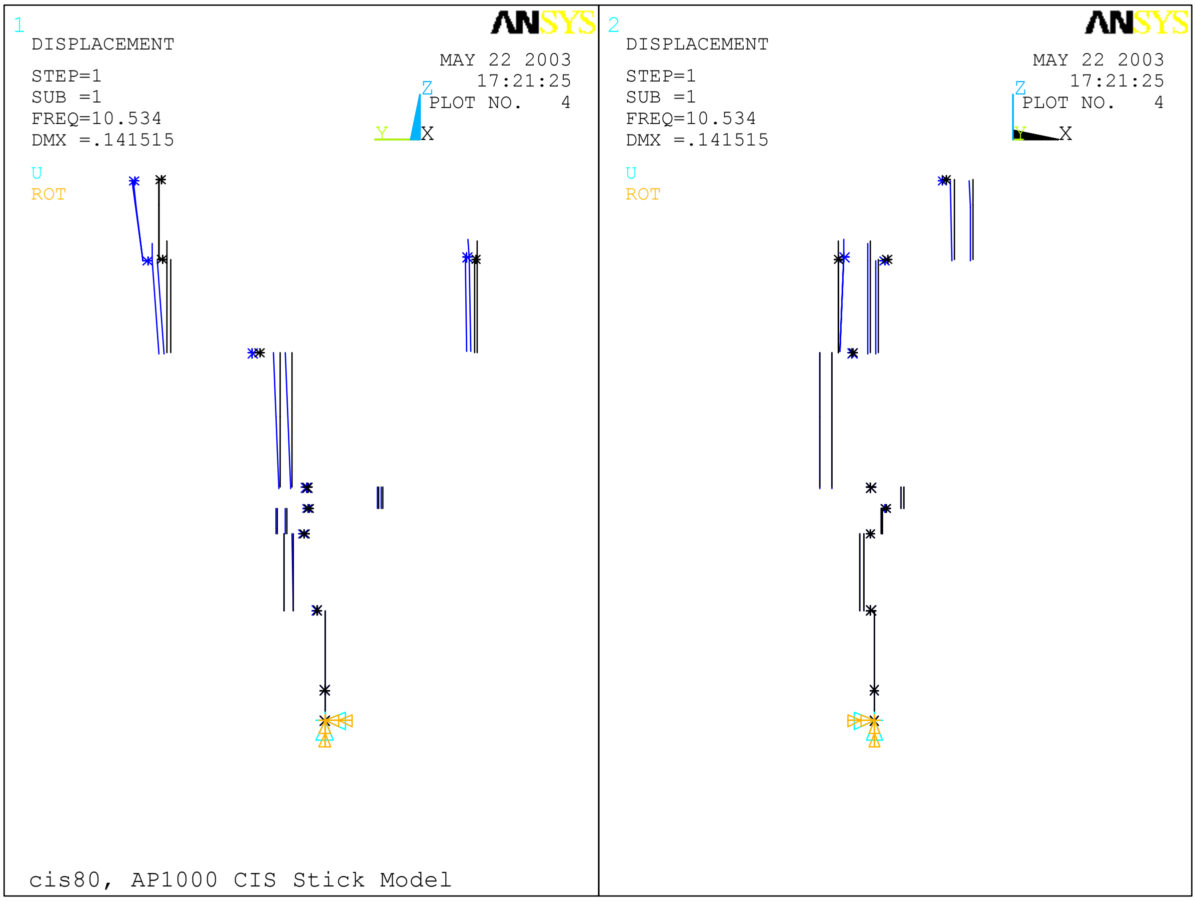


Figure 3.7.2-11 (Sheet 1 of 6)

Containment Internal Structures Without RCL Modeshape Plots

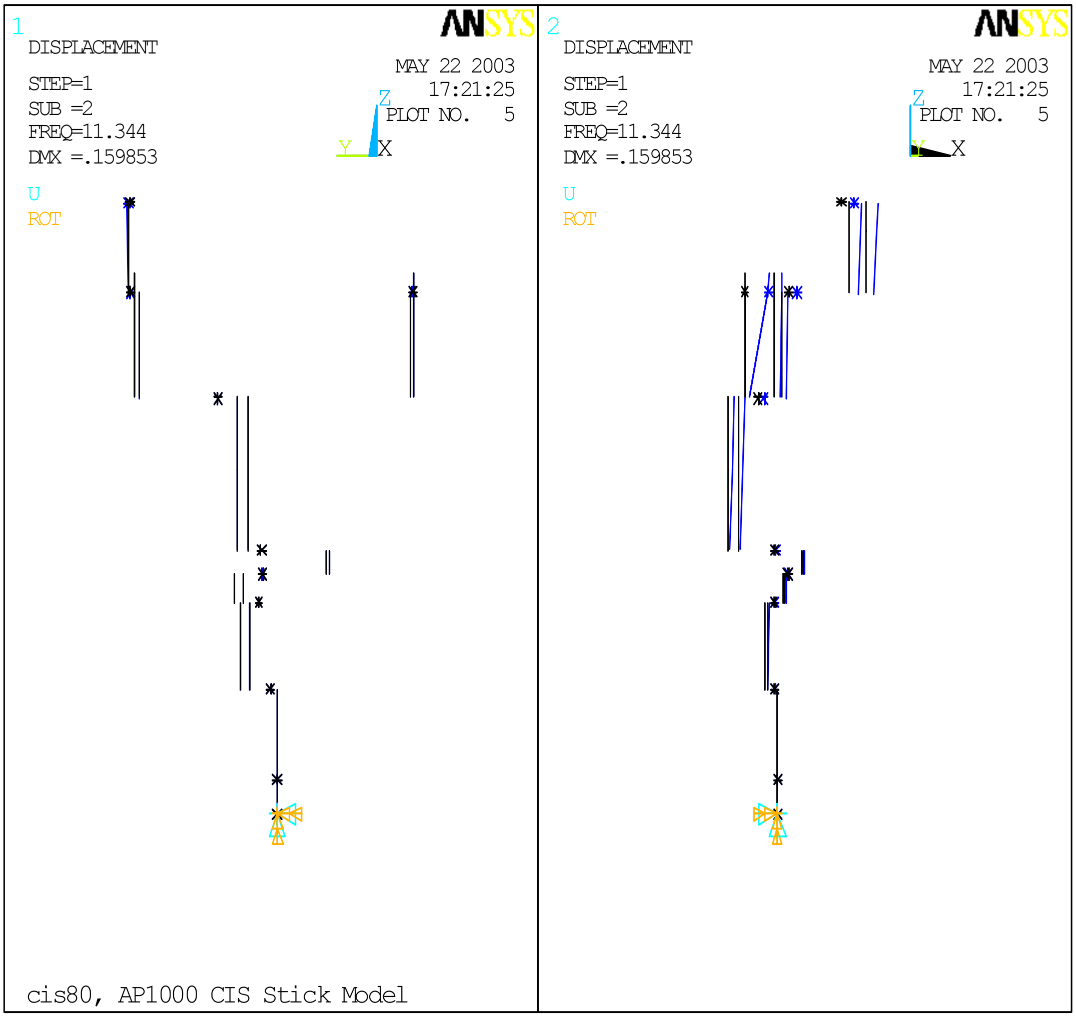


Figure 3.7.2-11 (Sheet 2 of 6)

Containment Internal Structures Without RCL Modeshape Plots

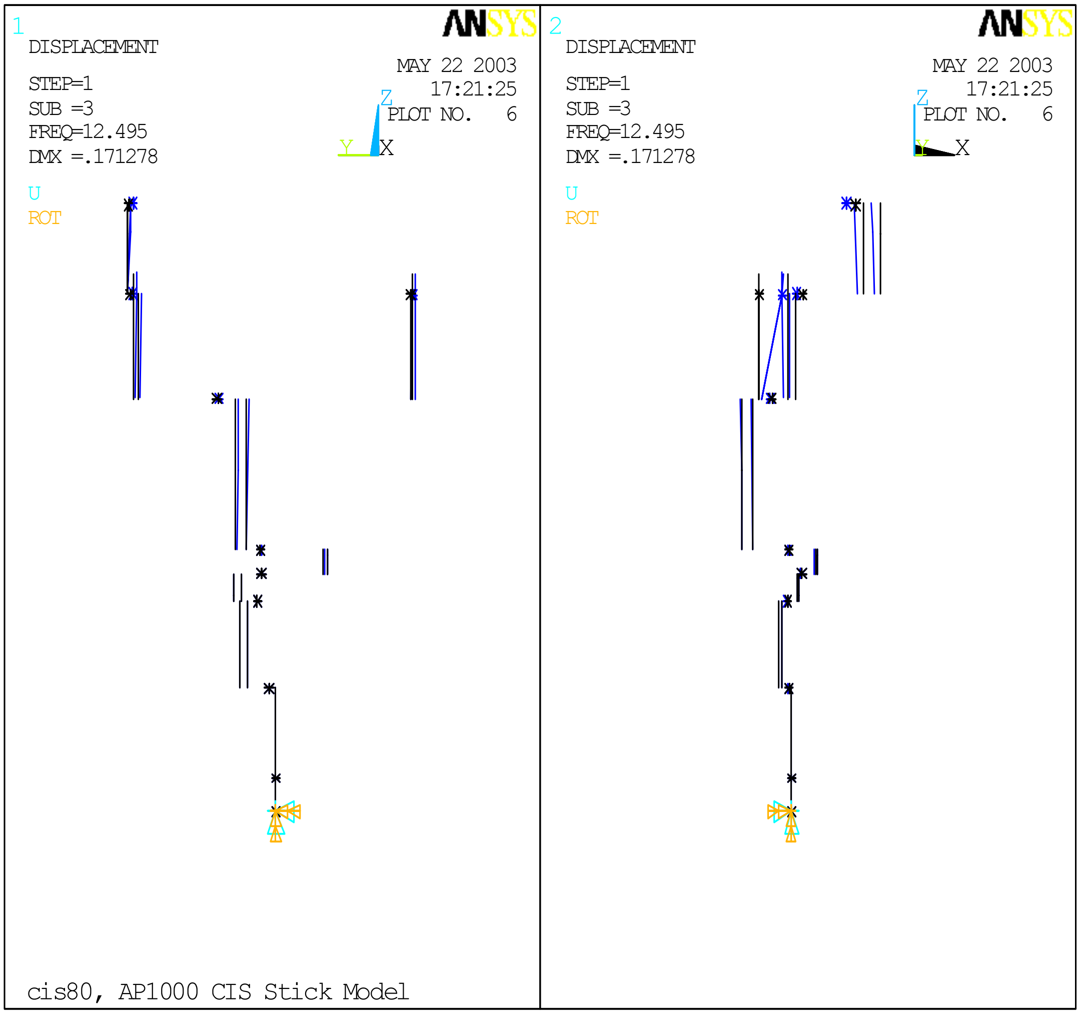


Figure 3.7.2-11 (Sheet 3 of 6)

Containment Internal Structures Without RCL
Modeshape Plots

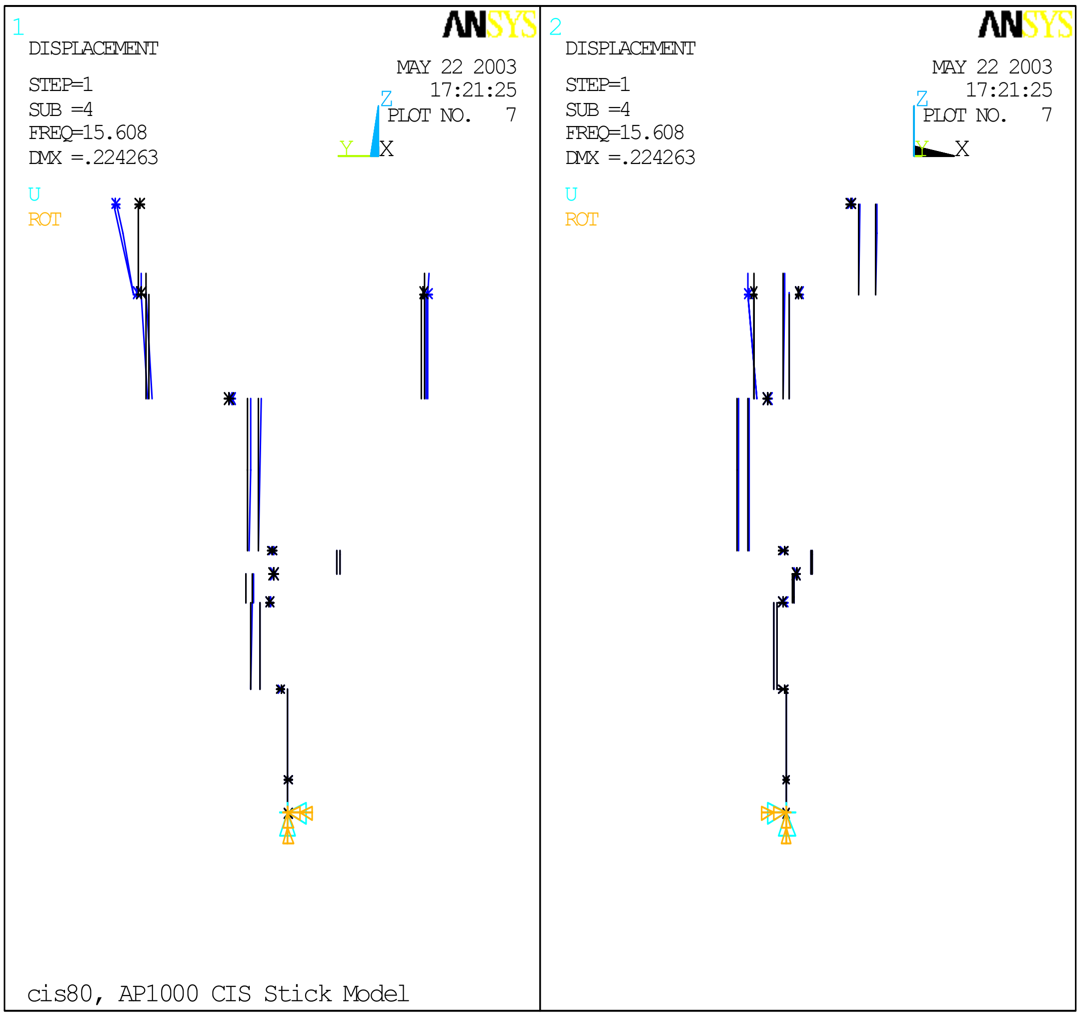


Figure 3.7.2-11 (Sheet 4 of 6)

Containment Internal Structures Without RCL Modeshape Plots

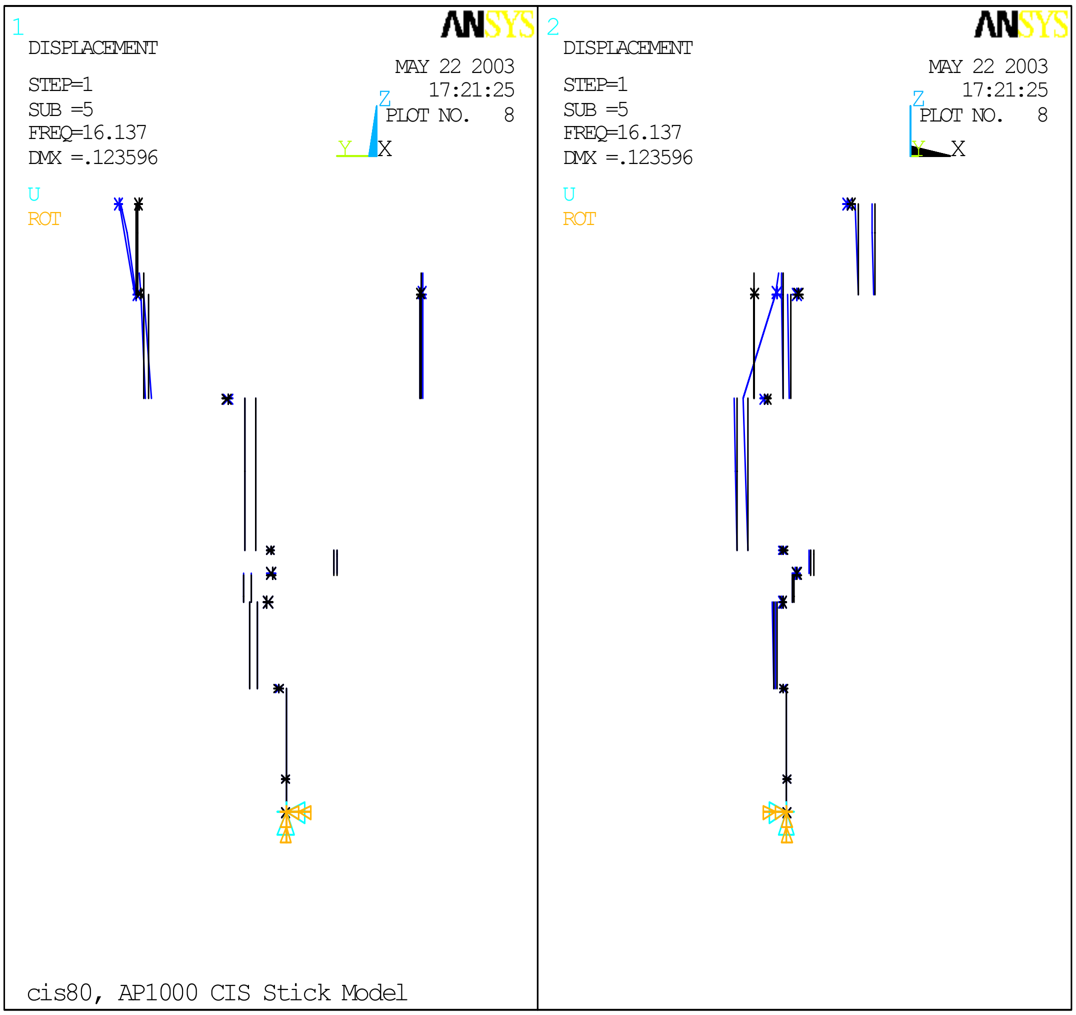


Figure 3.7.2-11 (Sheet 5 of 6)

Containment Internal Structures Without RCL Modeshape Plots

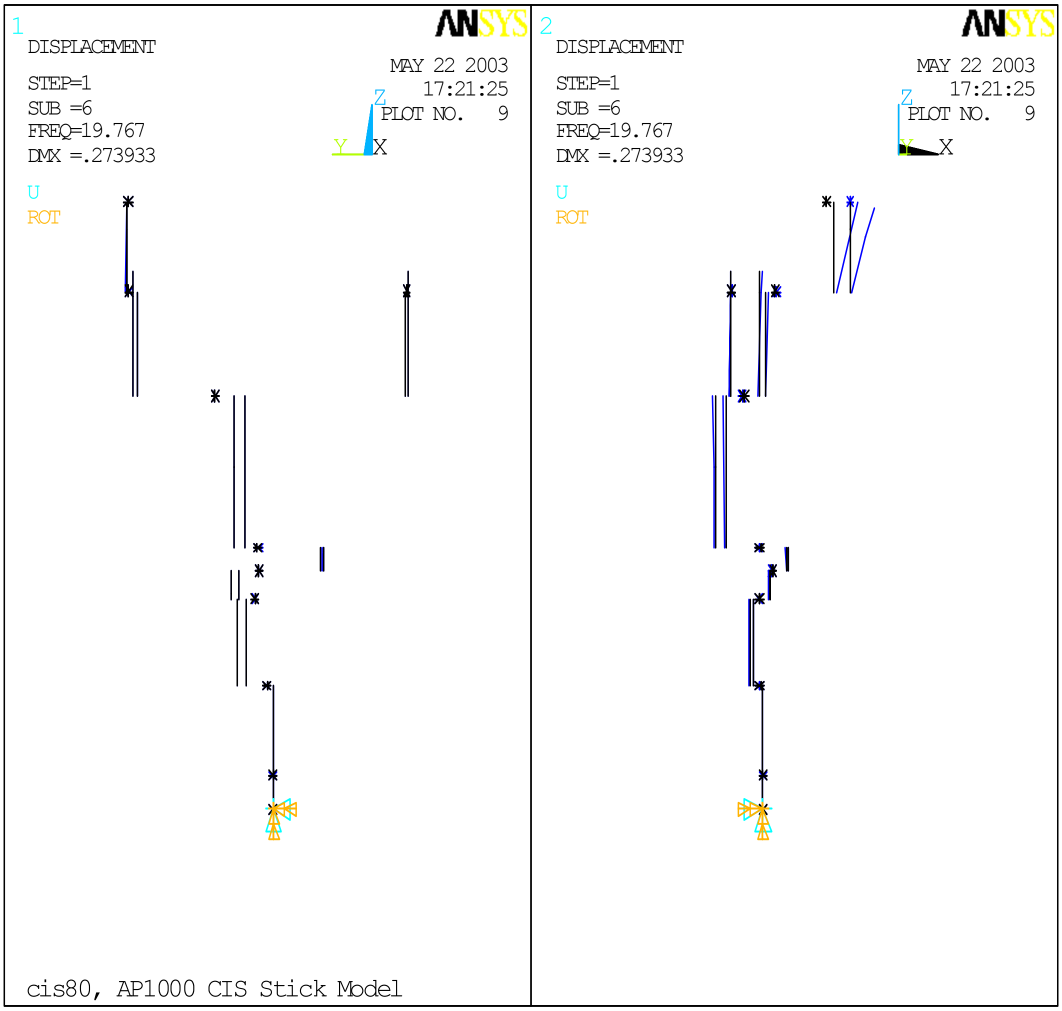


Figure 3.7.2-11 (Sheet 6 of 6)

Containment Internal Structures Without RCL Modeshape Plots

[This page intentionally blank]

Withheld under 10 CFR 2.390.

Figure 3.7.2-12 (Sheet 1 of 12)

**[Nuclear Island Key Structural Dimensions
Plan at El. 66′-6″]***

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 3.7.2-12 (Sheet 2 of 12)

**[Nuclear Island Key Structural Dimensions
Plan at El. 82′-6″]***

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 3.7.2-12 (Sheet 3 of 12)

**[Nuclear Island Key Structural Dimensions
Plan at El. 100′-0″& 107′-2″]***

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 3.7.2-12 (Sheet 4 of 12)

**[*Nuclear Island Key Structural Dimensions*
Plan at El. 117′-6″]***

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 3.7.2-12 (Sheet 5 of 12)

**[Nuclear Island Key Structural Dimensions
Plan at El. 135′-3″]***

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 3.7.2-12 (Sheet 6 of 12)

**[Nuclear Island Key Structural Dimensions
Plan at El. 153′-0″ & 160′-6″]***

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 3.7.2-12 (Sheet 7 of 12)

**[Nuclear Island Key Structural Dimensions
Plan at El. 160′-6″ & 180′-0″]***

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 3.7.2-12 (Sheet 8 of 12)

**[Nuclear Island Key Structural Dimensions
Section A - A]***

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 3.7.2-12 (Sheet 9 of 12)

**[Nuclear Island Key Structural Dimensions
Section B - B]***

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 3.7.2-12 (Sheet 10 of 12)

**[*Nuclear Island Key Structural Dimensions*
Sections C - C and H - H]***

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 3.7.2-12 (Sheet 11 of 12)

**[Nuclear Island Key Structural Dimensions
Section G - G]***

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Withheld under 10 CFR 2.390.

Figure 3.7.2-12 (Sheet 12 of 12)

**[Nuclear Island Key Structural Dimensions
Section J - J]***

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

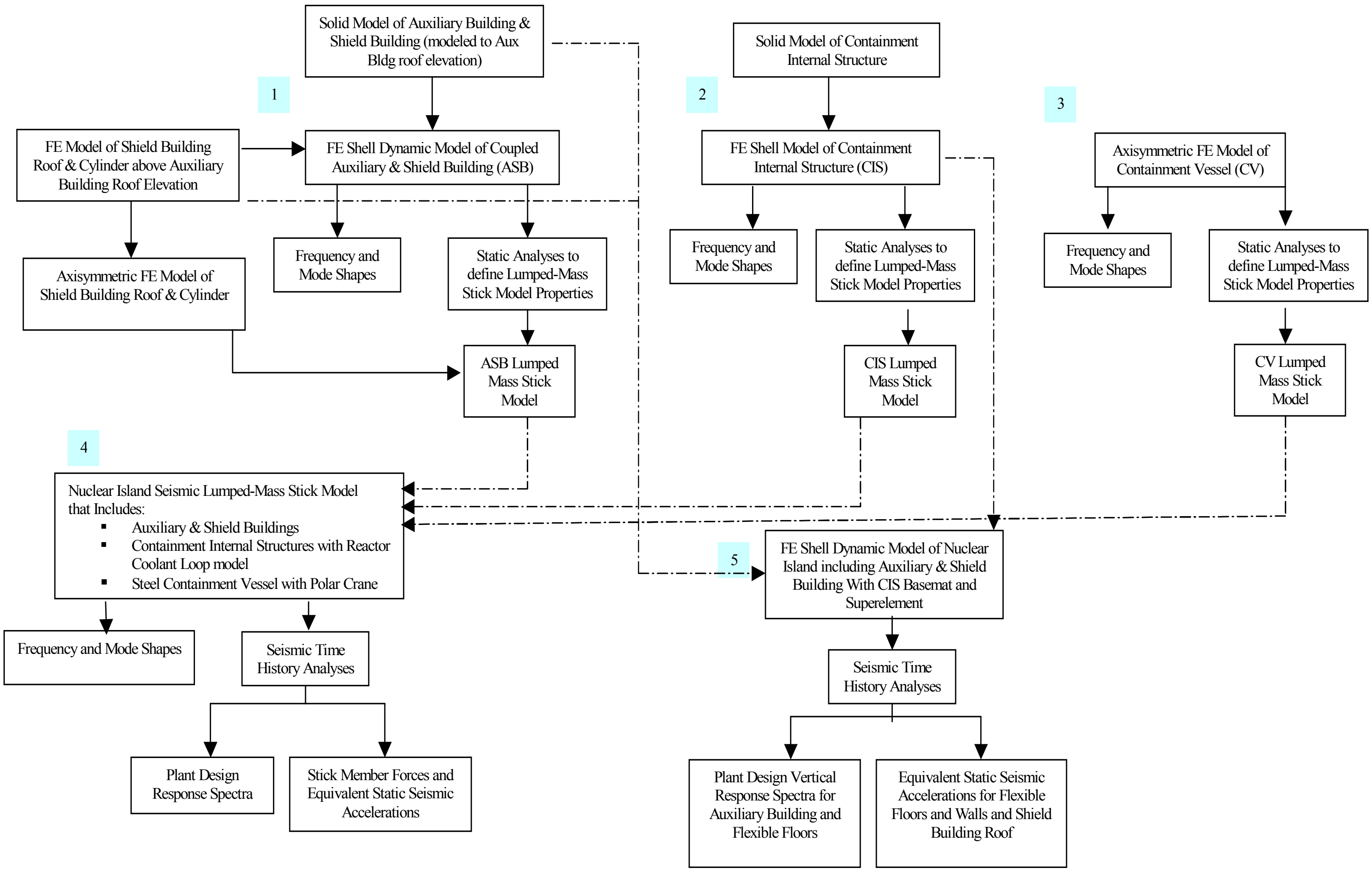


Figure 3.7.2-13

Nuclear Island Seismic Analysis Models

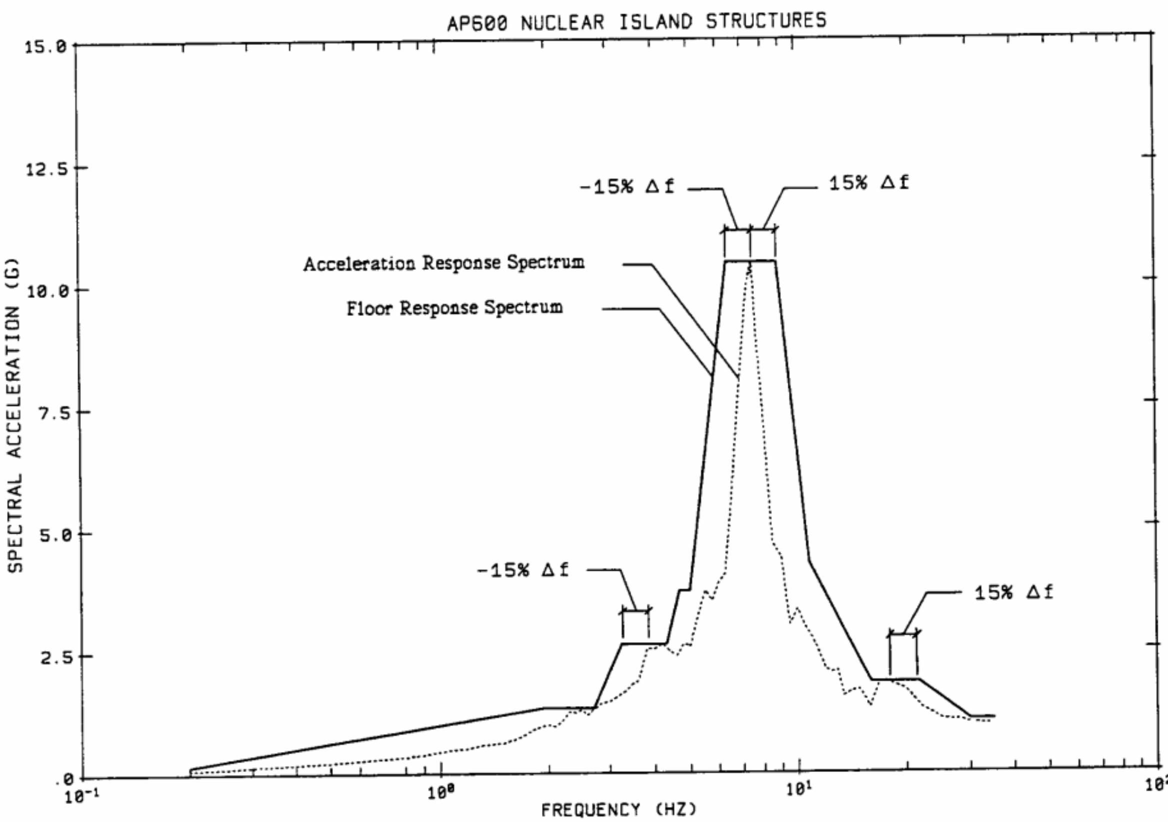


Figure 3.7.2-14

Typical Design Floor Response Spectrum

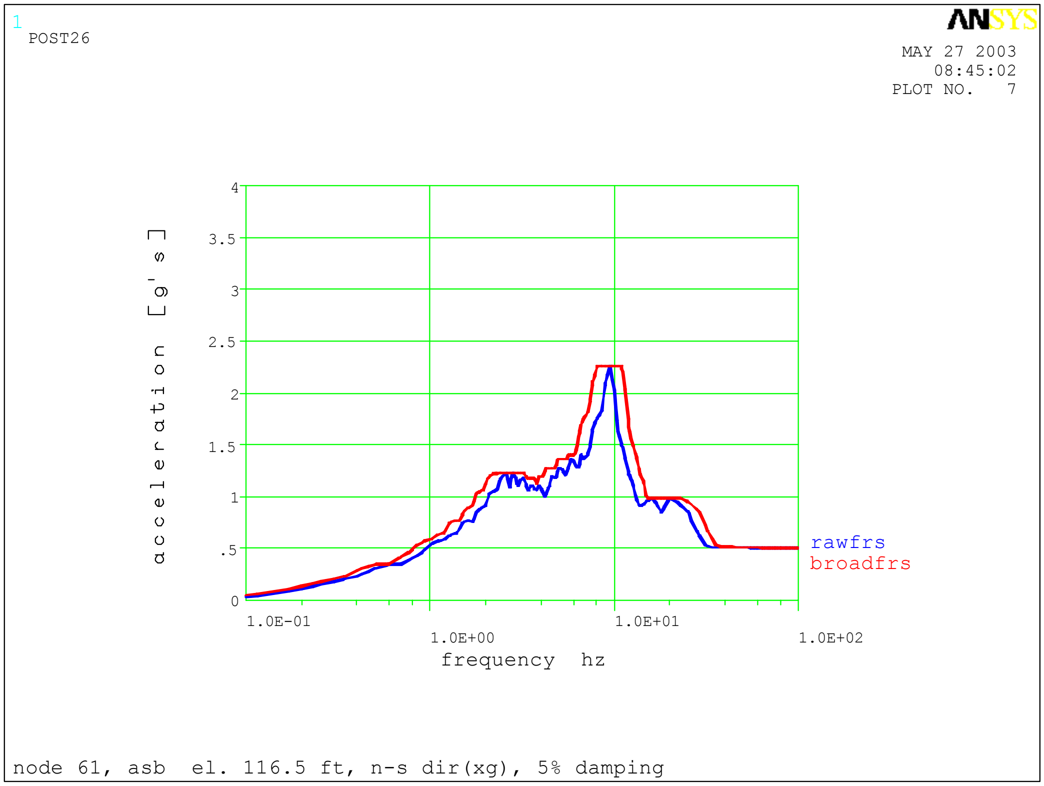


Figure 3.7.2-15 (Sheet 1 of 15)

Coupled Shield and Auxiliary Buildings SSE Floor Response Spectra

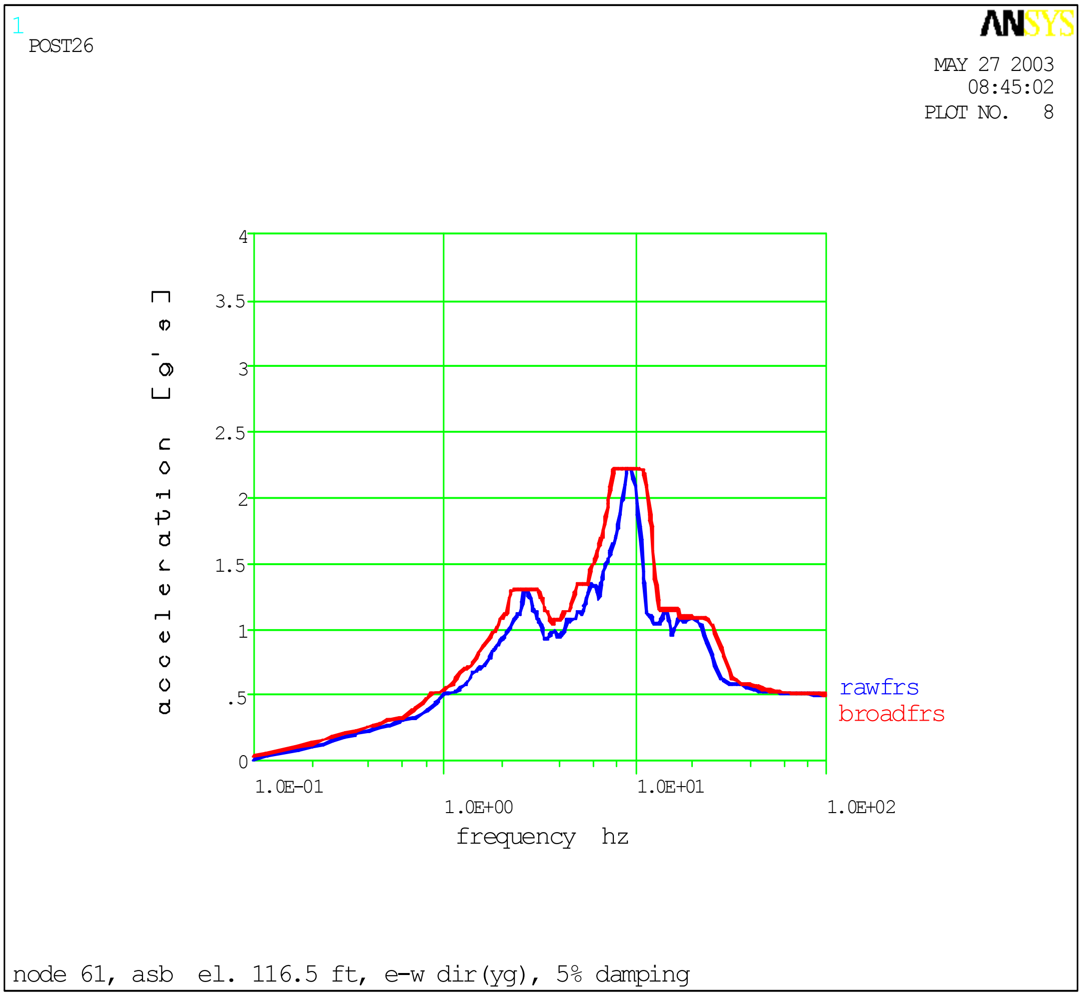


Figure 3.7.2-15 (Sheet 2 of 15)

Coupled Shield and Auxiliary Buildings SSE Floor Response Spectra

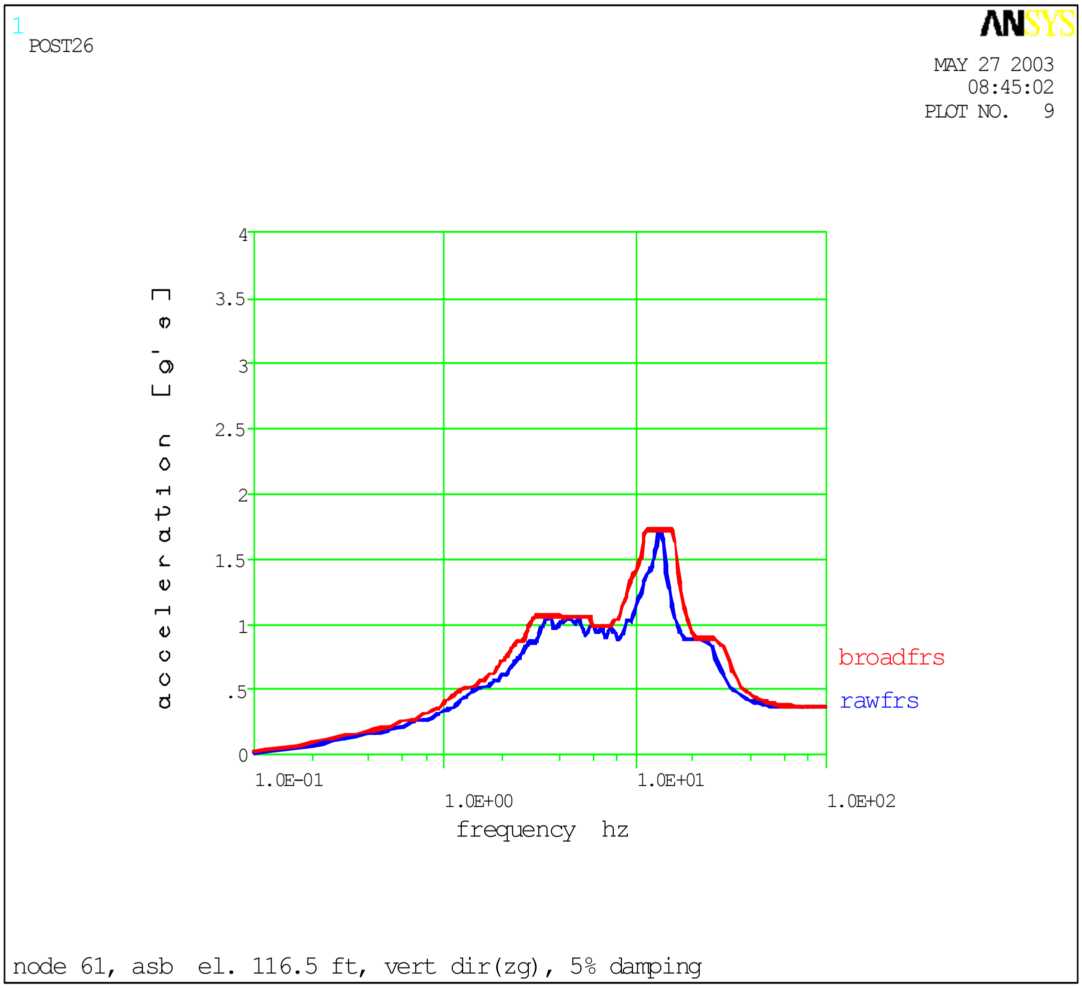


Figure 3.7.2-15 (Sheet 3 of 15)

Coupled Shield and Auxiliary Buildings SSE Floor Response Spectra

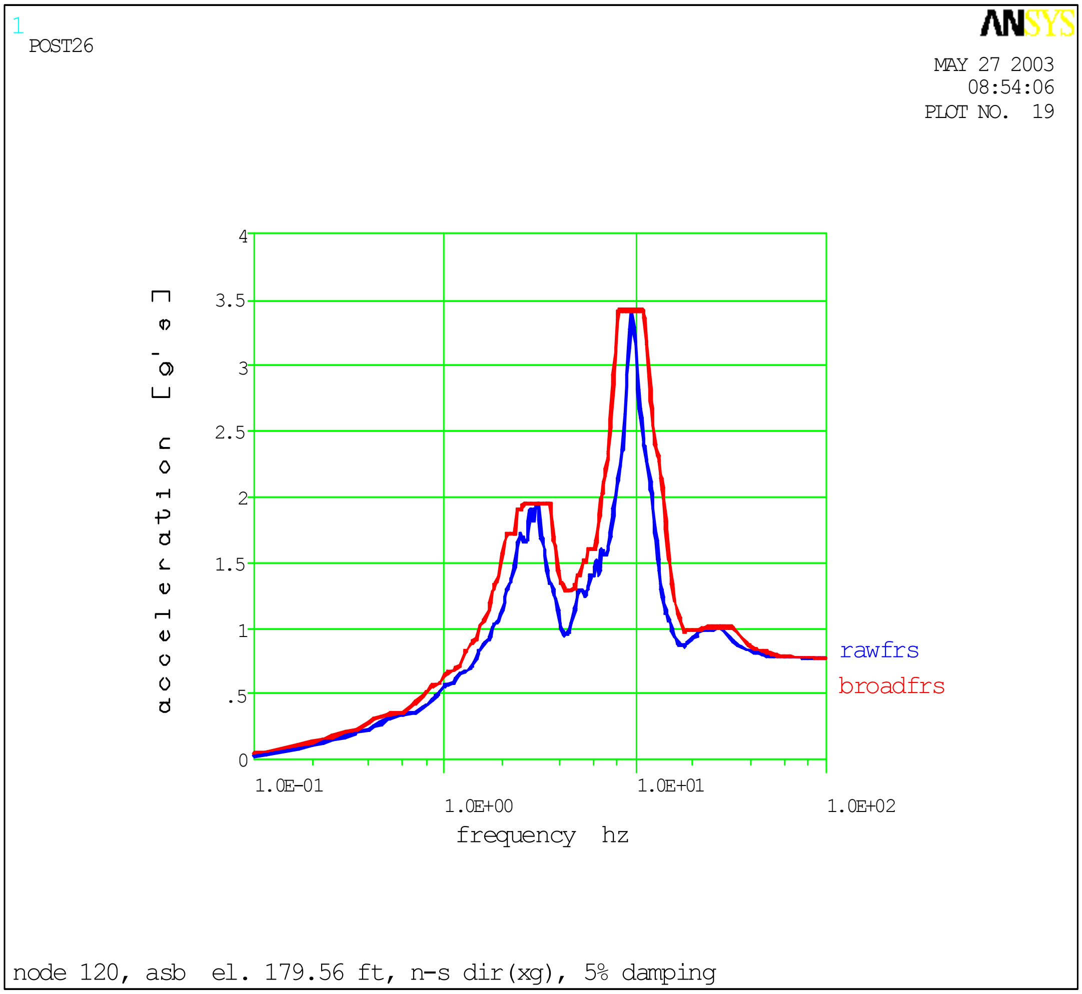


Figure 3.7.2-15 (Sheet 4 of 15)

Coupled Shield and Auxiliary Buildings SSE Floor Response Spectra

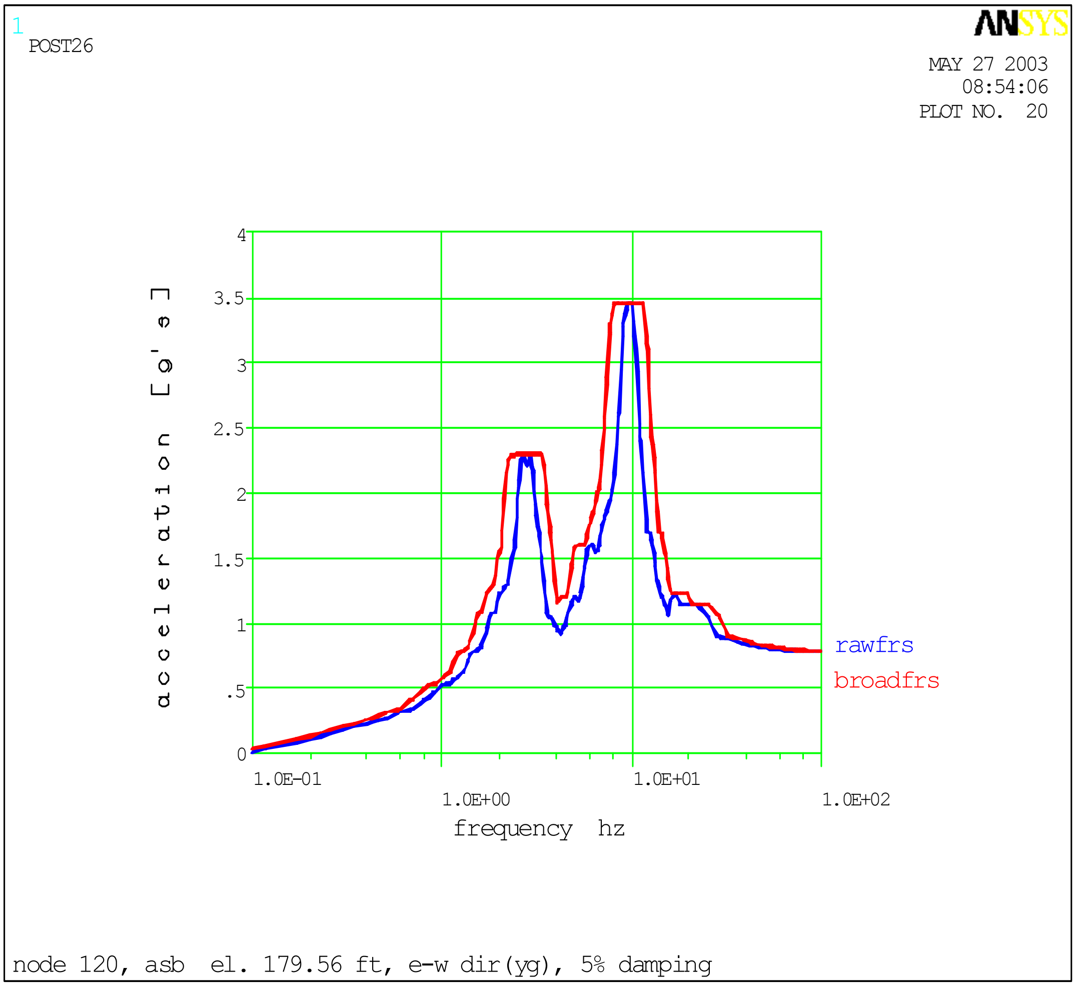


Figure 3.7.2-15 (Sheet 5 of 15)

Coupled Shield and Auxiliary Buildings SSE Floor Response Spectra

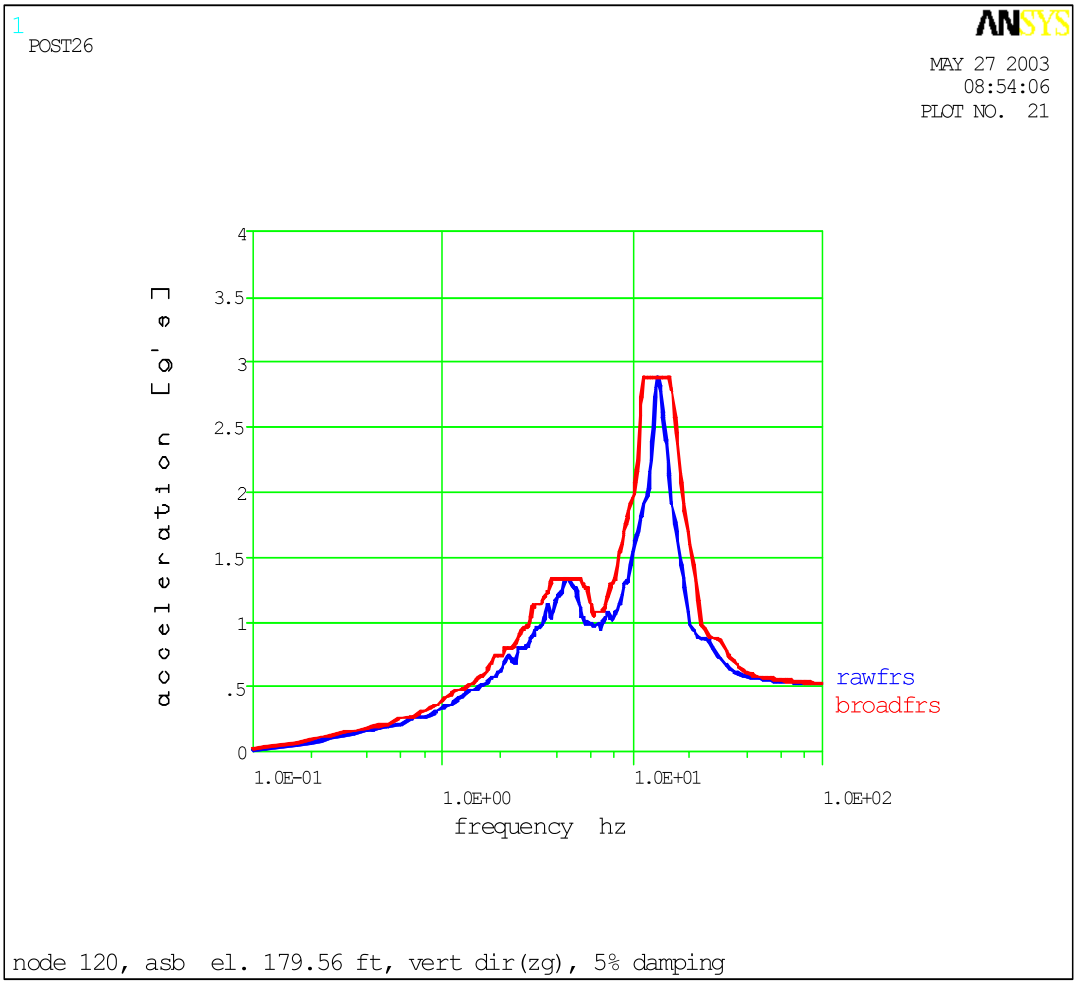


Figure 3.7.2-15 (Sheet 6 of 15)

Coupled Shield and Auxiliary Buildings SSE Floor Response Spectra

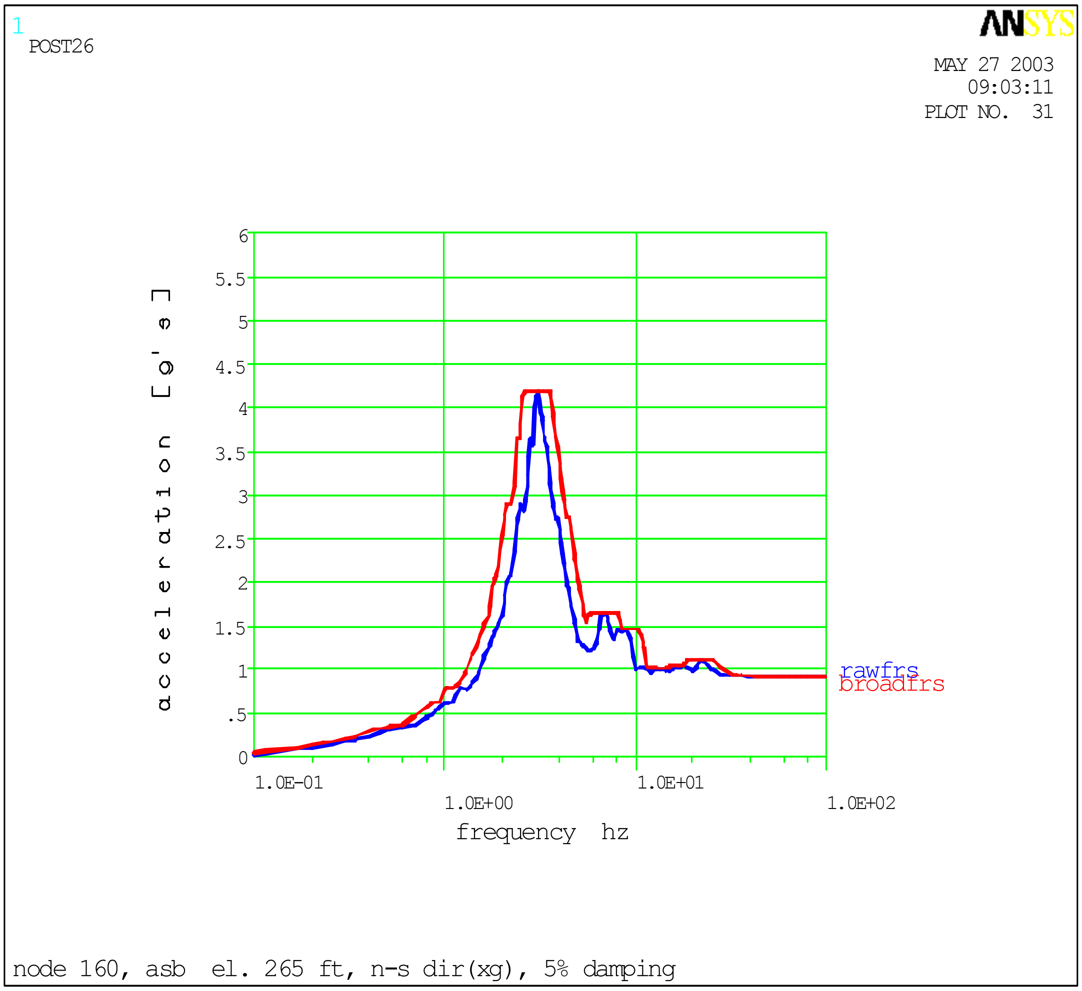


Figure 3.7.2-15 (Sheet 7 of 15)

Coupled Shield and Auxiliary Buildings SSE Floor Response Spectra

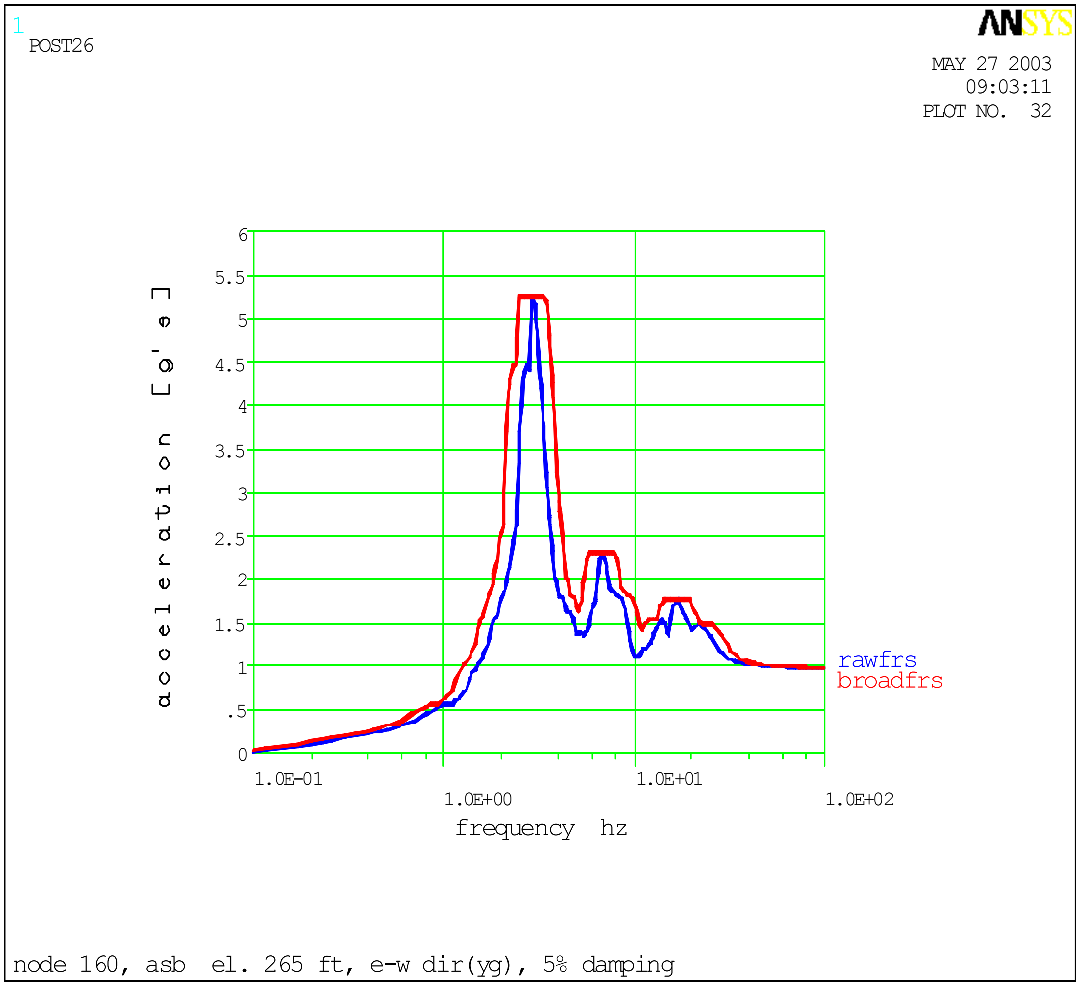


Figure 3.7.2-15 (Sheet 8 of 15)

Coupled Shield and Auxiliary Buildings SSE Floor Response Spectra

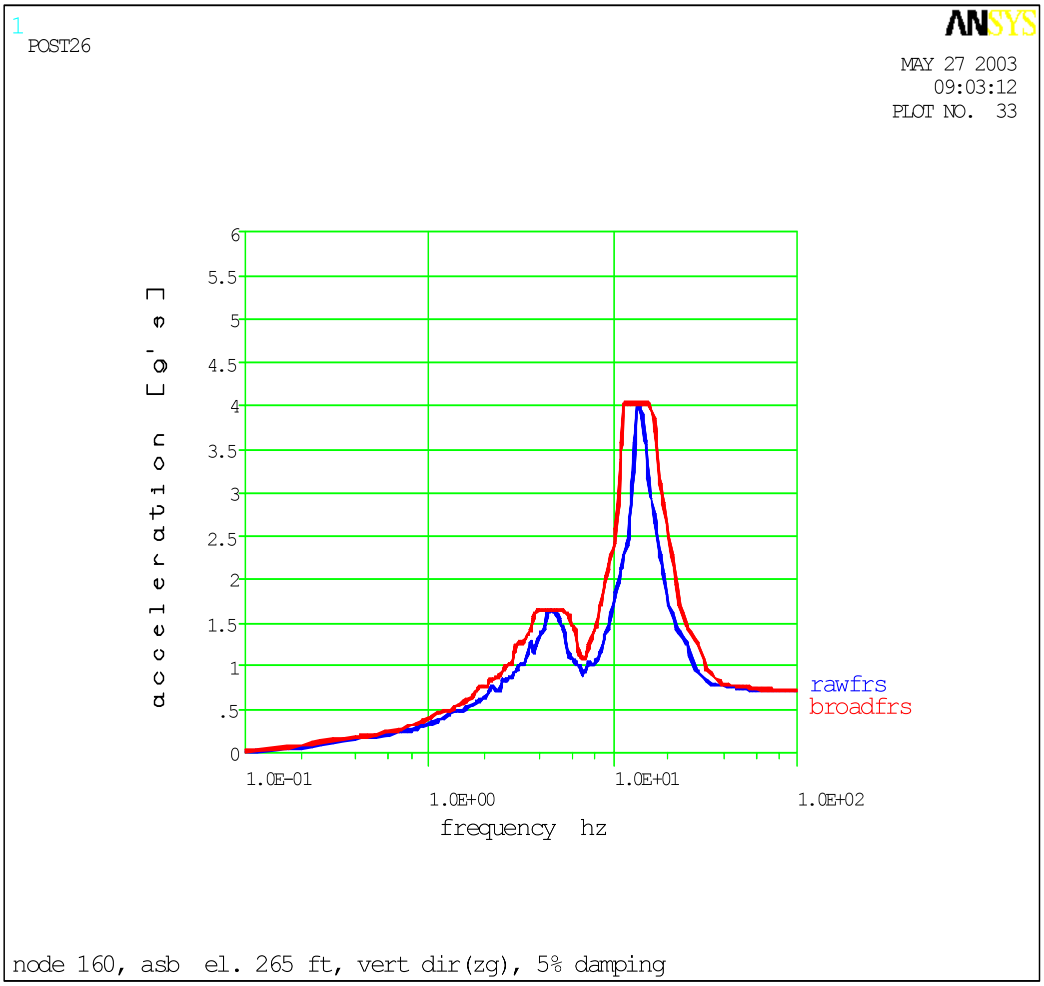


Figure 3.7.2-15 (Sheet 9 of 15)

Coupled Shield and Auxiliary Buildings SSE Floor Response Spectra

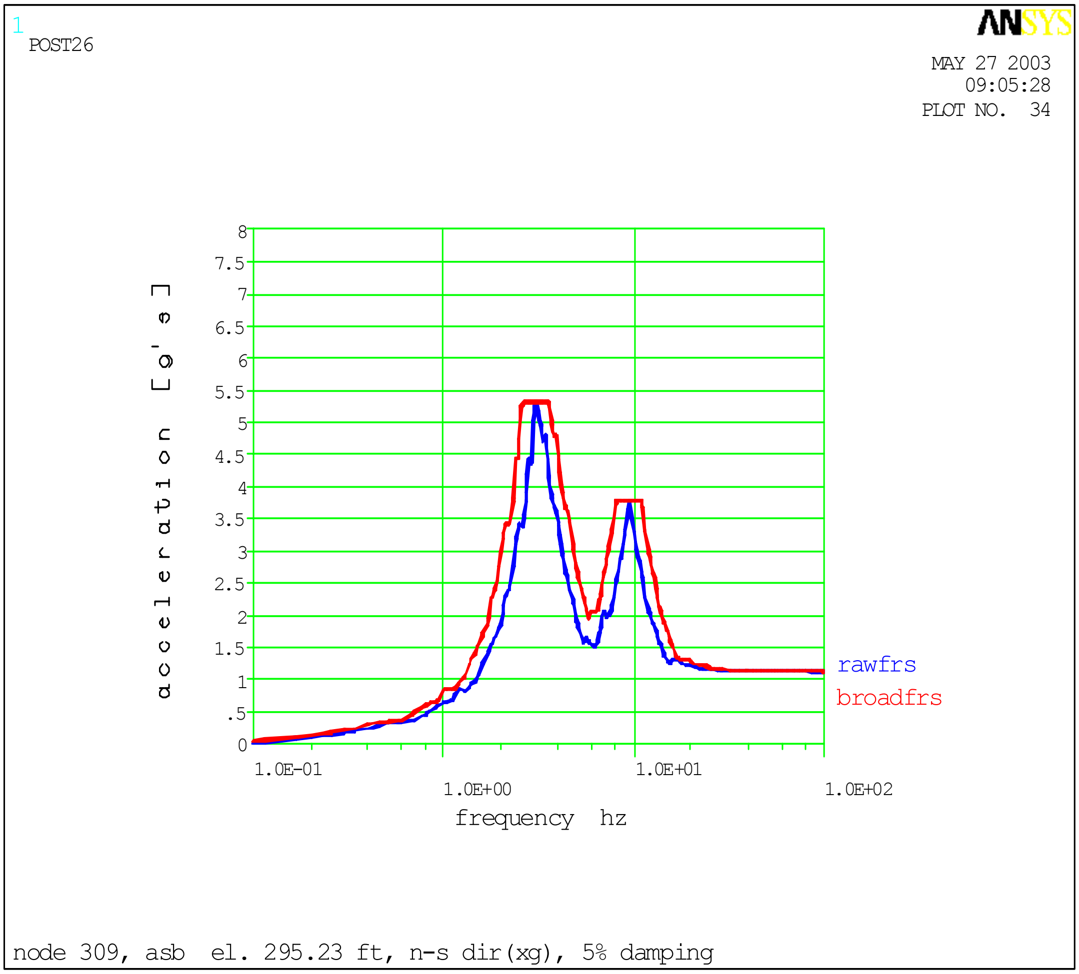


Figure 3.7.2-15 (Sheet 10 of 15)

Coupled Shield and Auxiliary Buildings SSE Floor Response Spectra

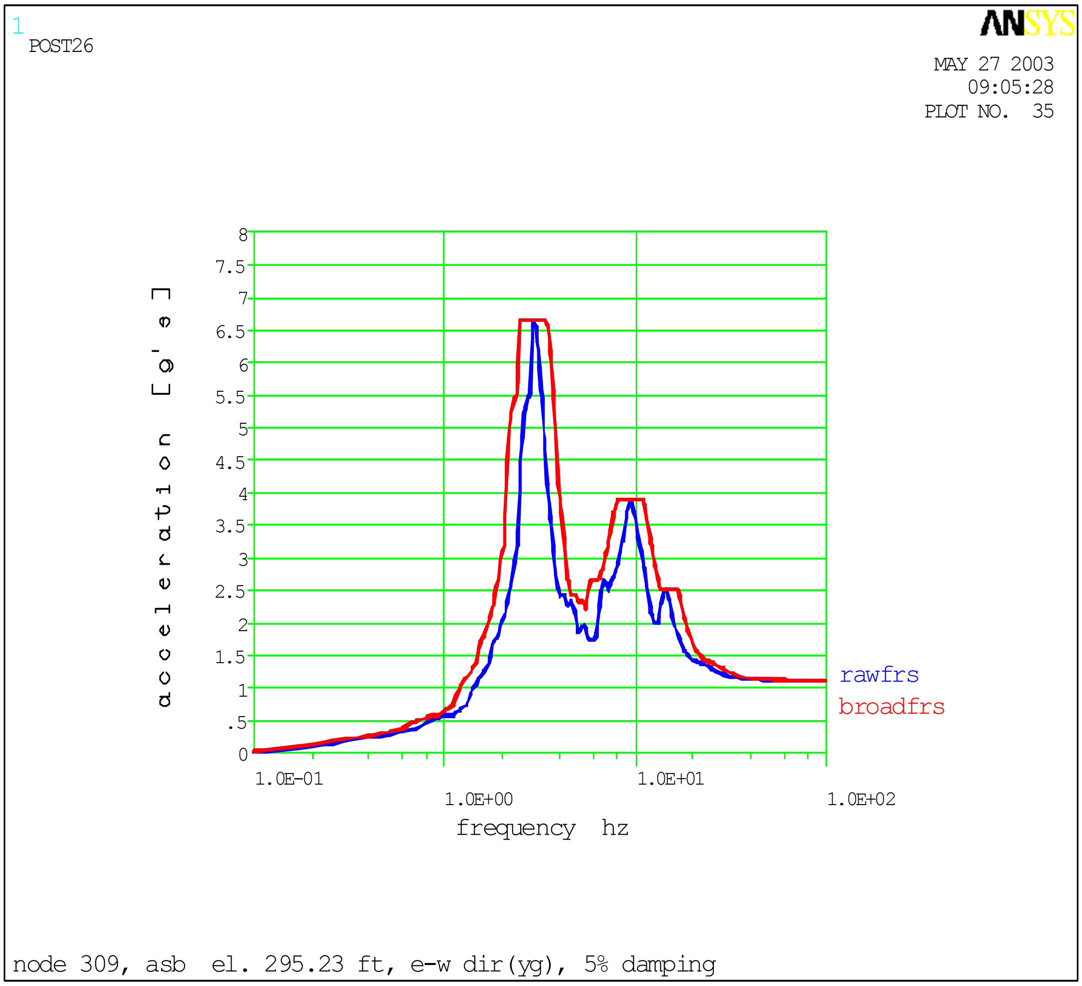


Figure 3.7.2-15 (Sheet 11 of 15)

Coupled Shield and Auxiliary Buildings SSE Floor Response Spectra

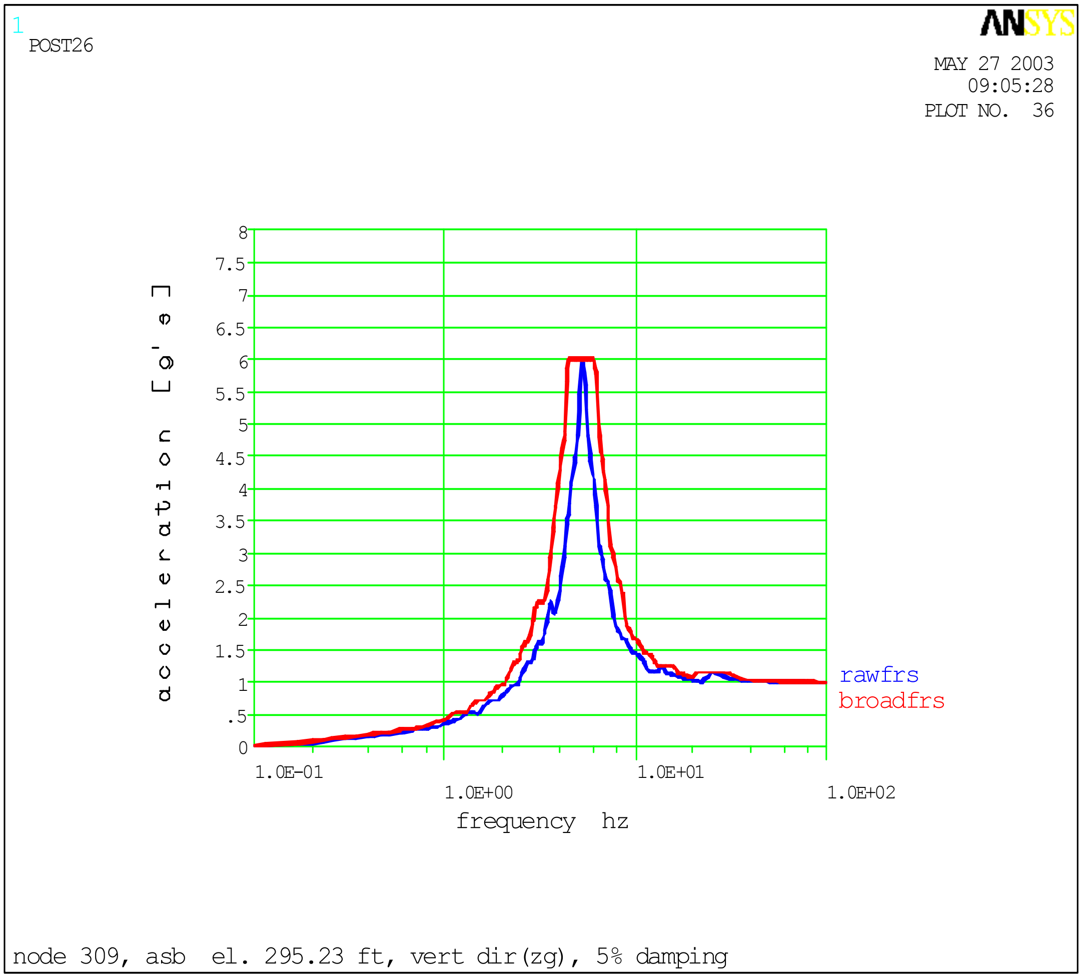


Figure 3.7.2-15 (Sheet 12 of 15)

Coupled Shield and Auxiliary Buildings SSE Floor Response Spectra

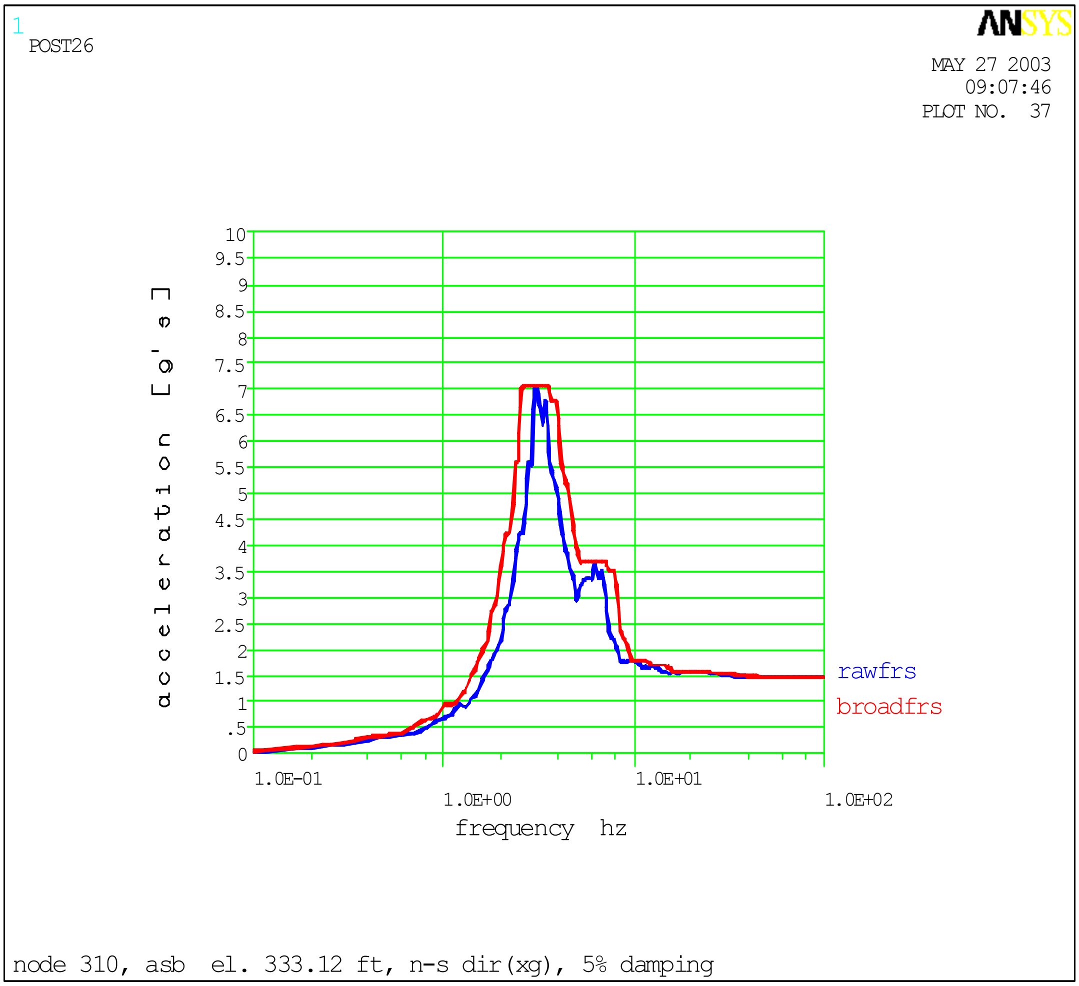


Figure 3.7.2-15 (Sheet 13 of 15)

Coupled Shield and Auxiliary Buildings SSE Floor Response Spectra

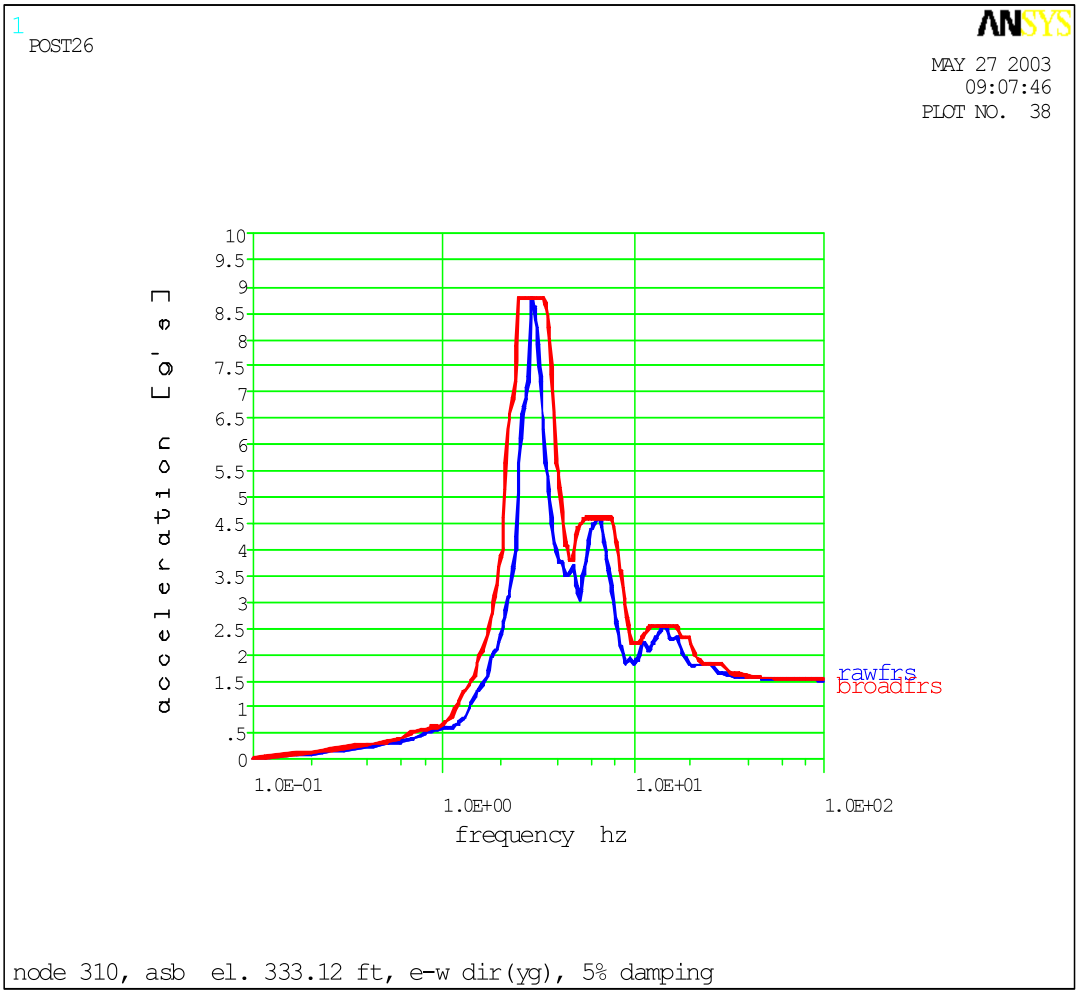


Figure 3.7.2-15 (Sheet 14 of 15)

Coupled Shield and Auxiliary Buildings SSE Floor Response Spectra

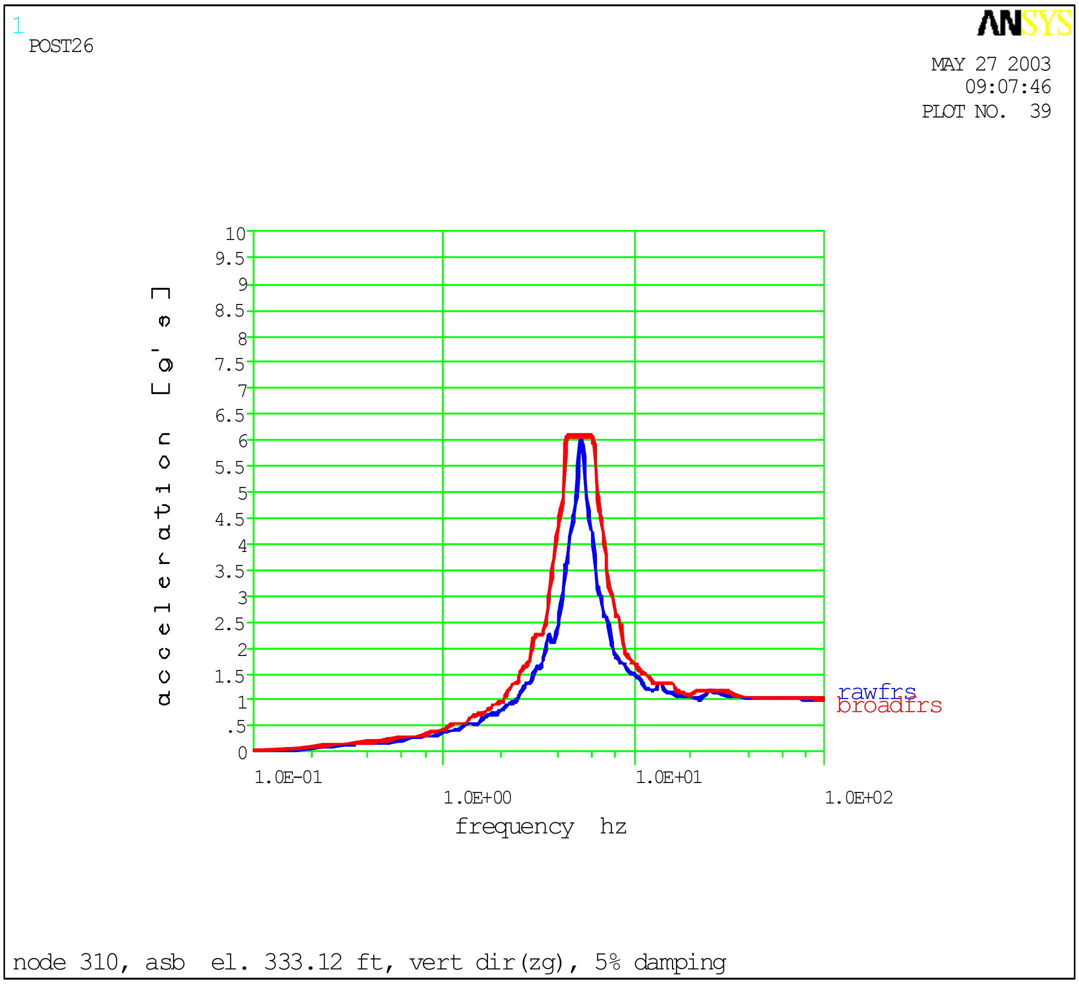


Figure 3.7.2-15 (Sheet 15 of 15)

Coupled Shield and Auxiliary Buildings SSE Floor Response Spectra

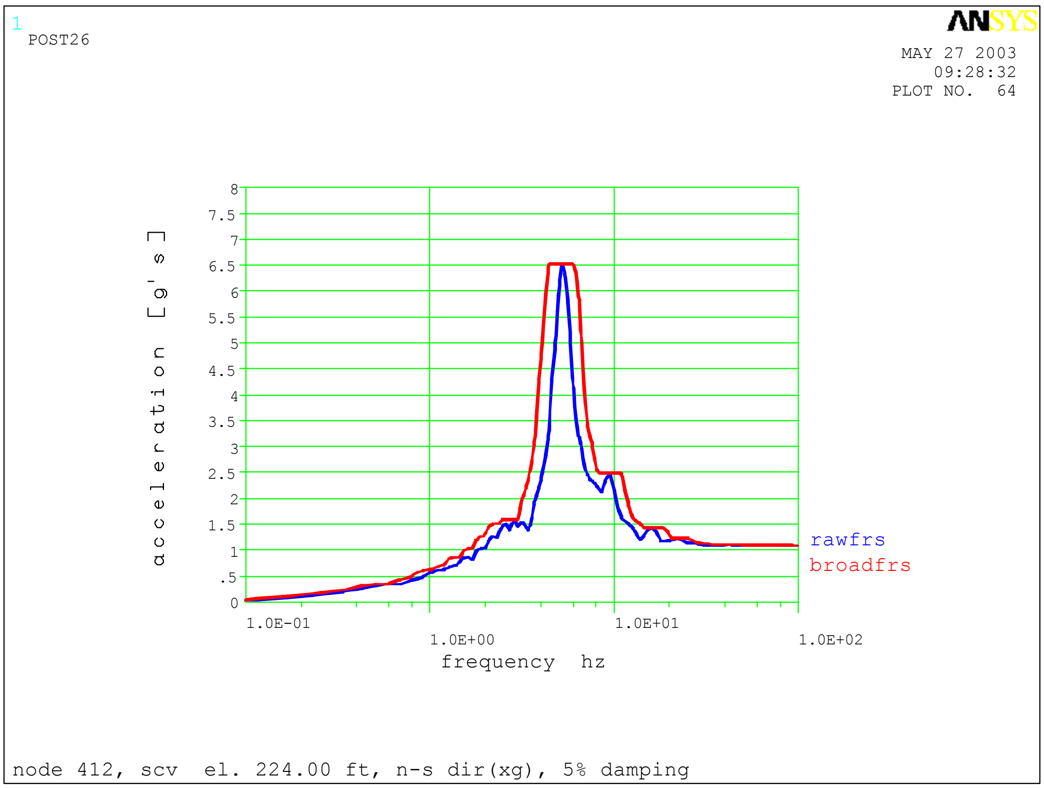


Figure 3.7.2-16 (Sheet 1 of 6)

Steel Containment Vessel SSE Floor Response Spectra

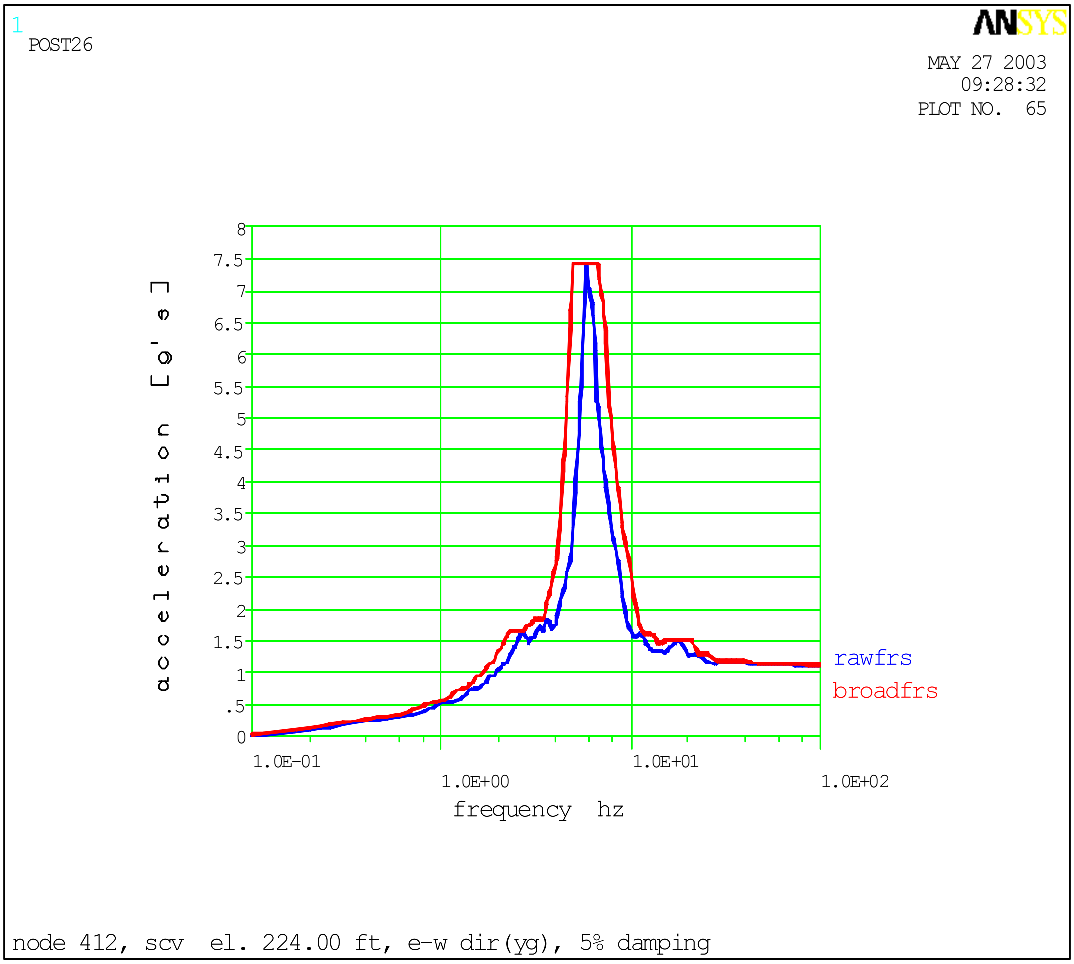


Figure 3.7.2-16 (Sheet 2 of 6)

Steel Containment Vessel SSE Floor Response Spectra

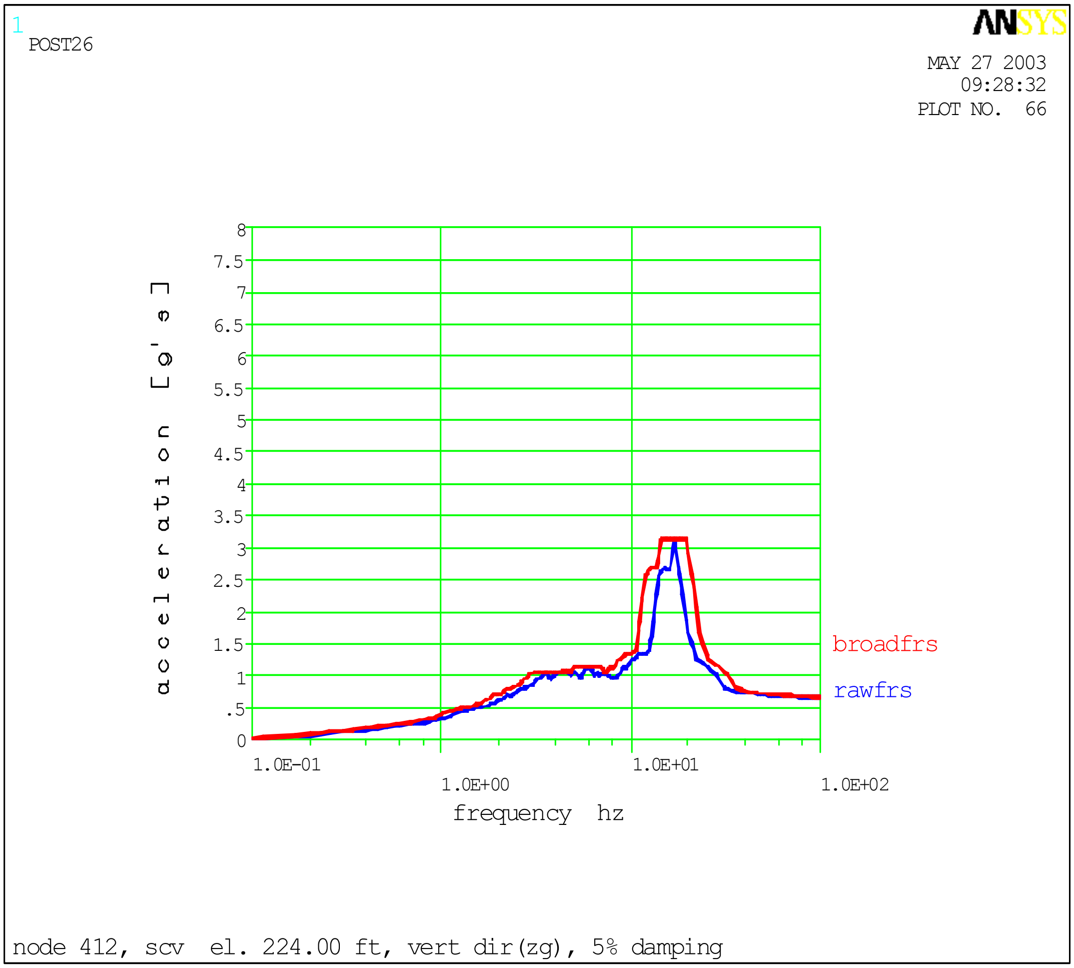


Figure 3.7.2-16 (Sheet 3 of 6)

Steel Containment Vessel SSE Floor Response Spectra

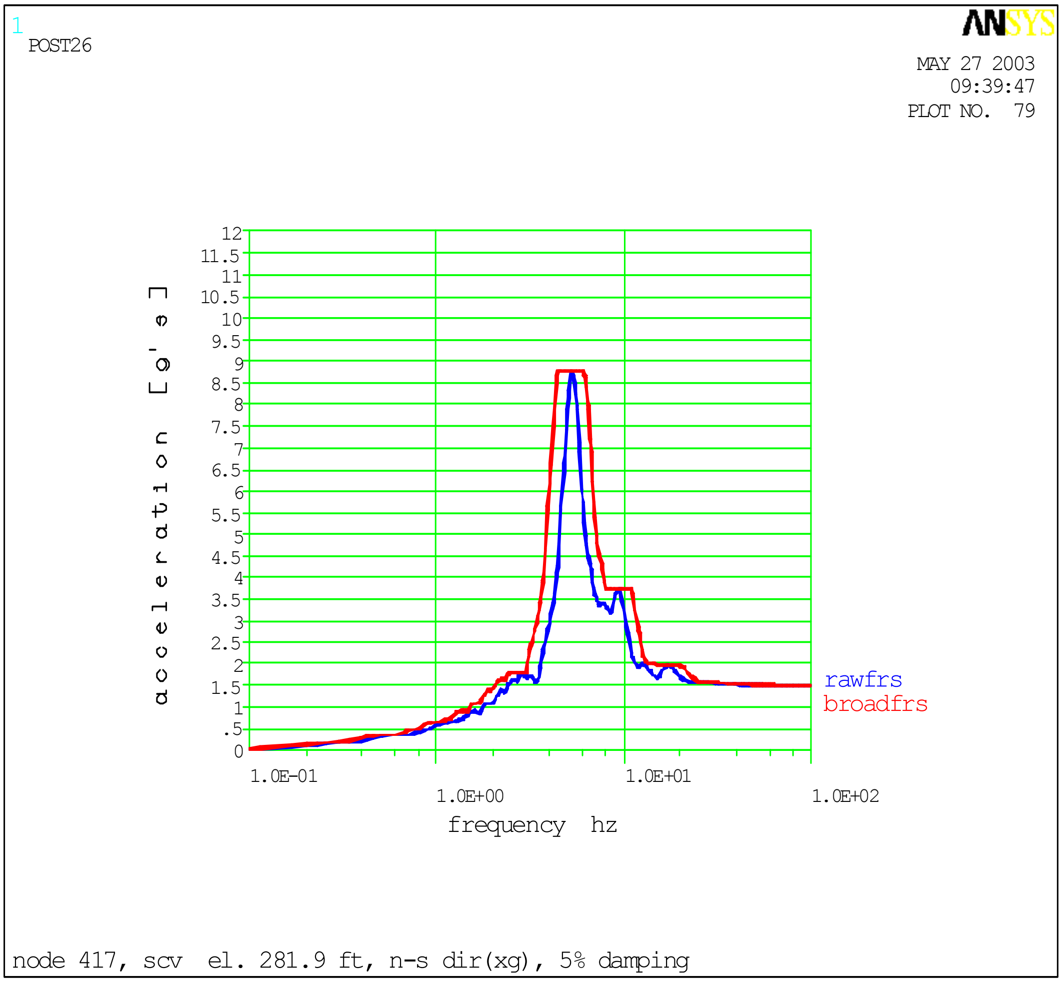


Figure 3.7.2-16 (Sheet 4 of 6)

Steel Containment Vessel SSE Floor Response Spectra

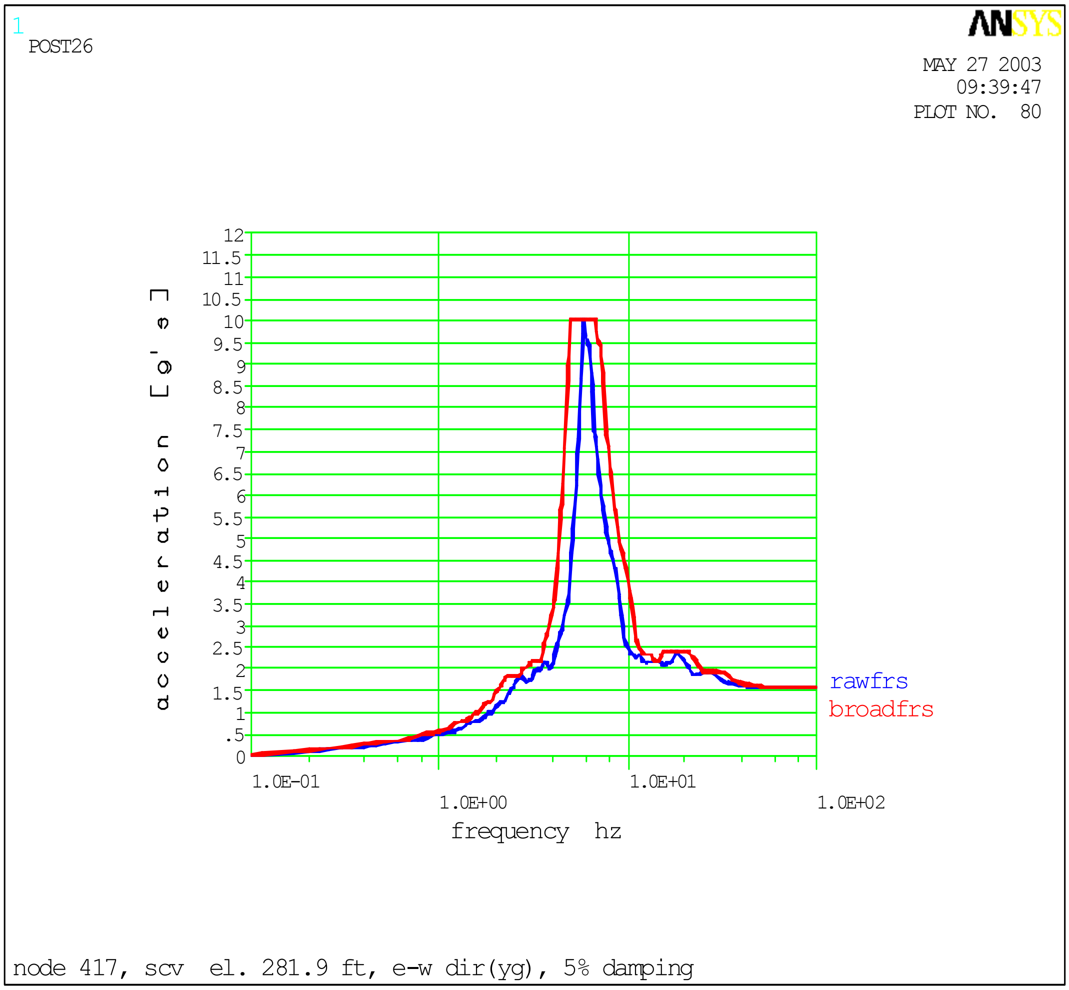


Figure 3.7.2-16 (Sheet 5 of 6)

Steel Containment Vessel SSE Floor Response Spectra

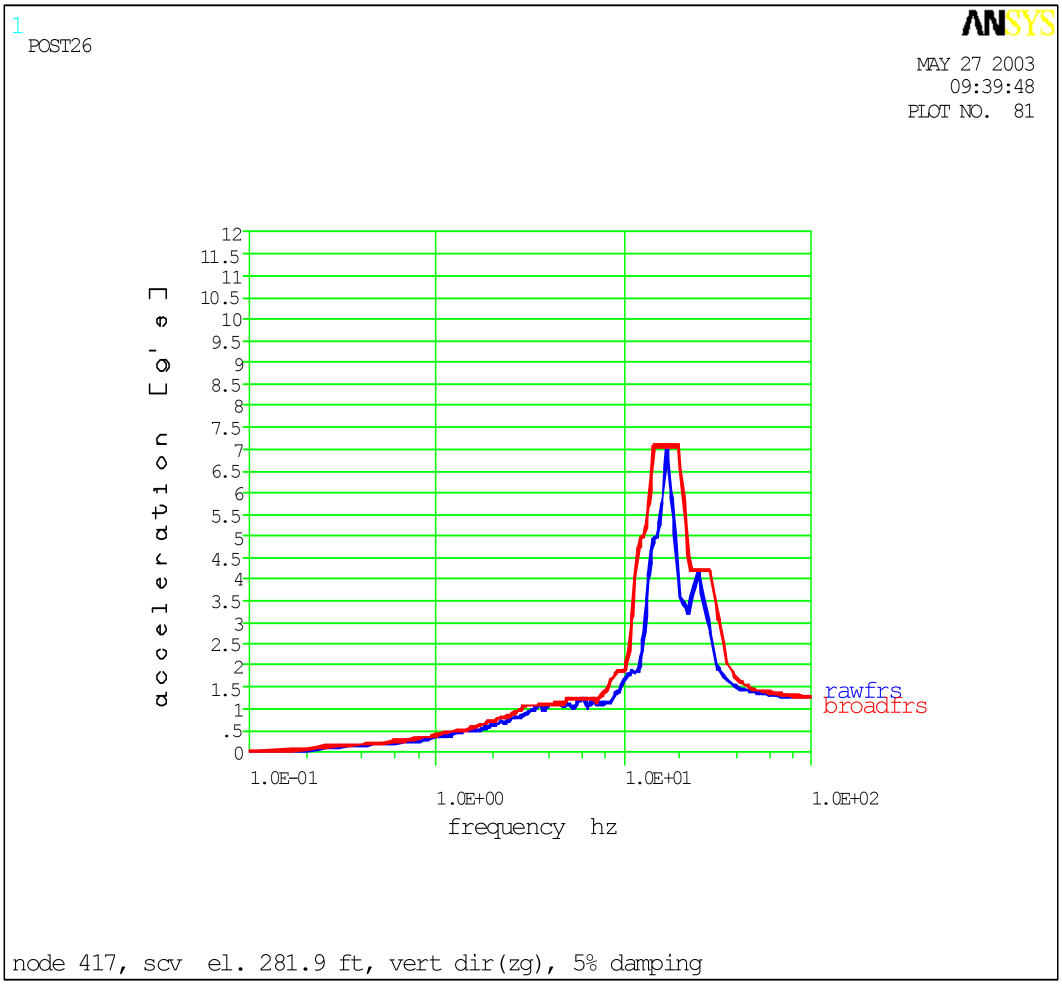


Figure 3.7.2-16 (Sheet 6 of 6)

Steel Containment Vessel SSE Floor Response Spectra

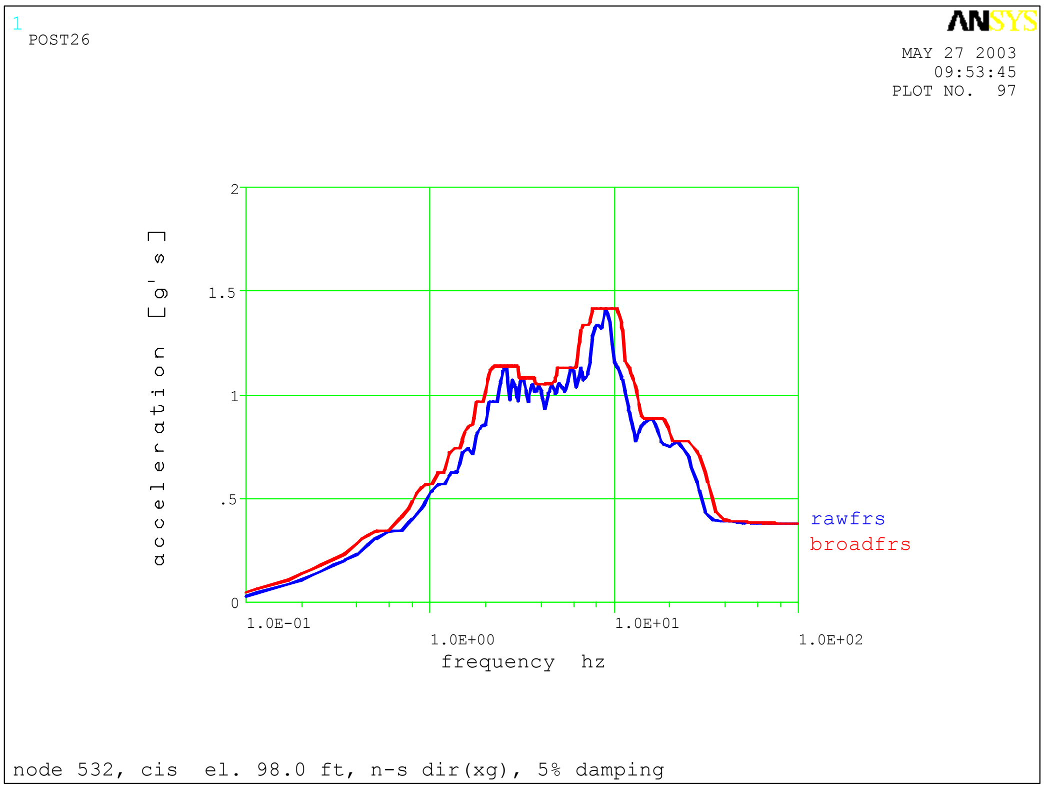


Figure 3.7.2-17 (Sheet 1 of 9)

Containment Internal Structures SSE Floor Response Spectra

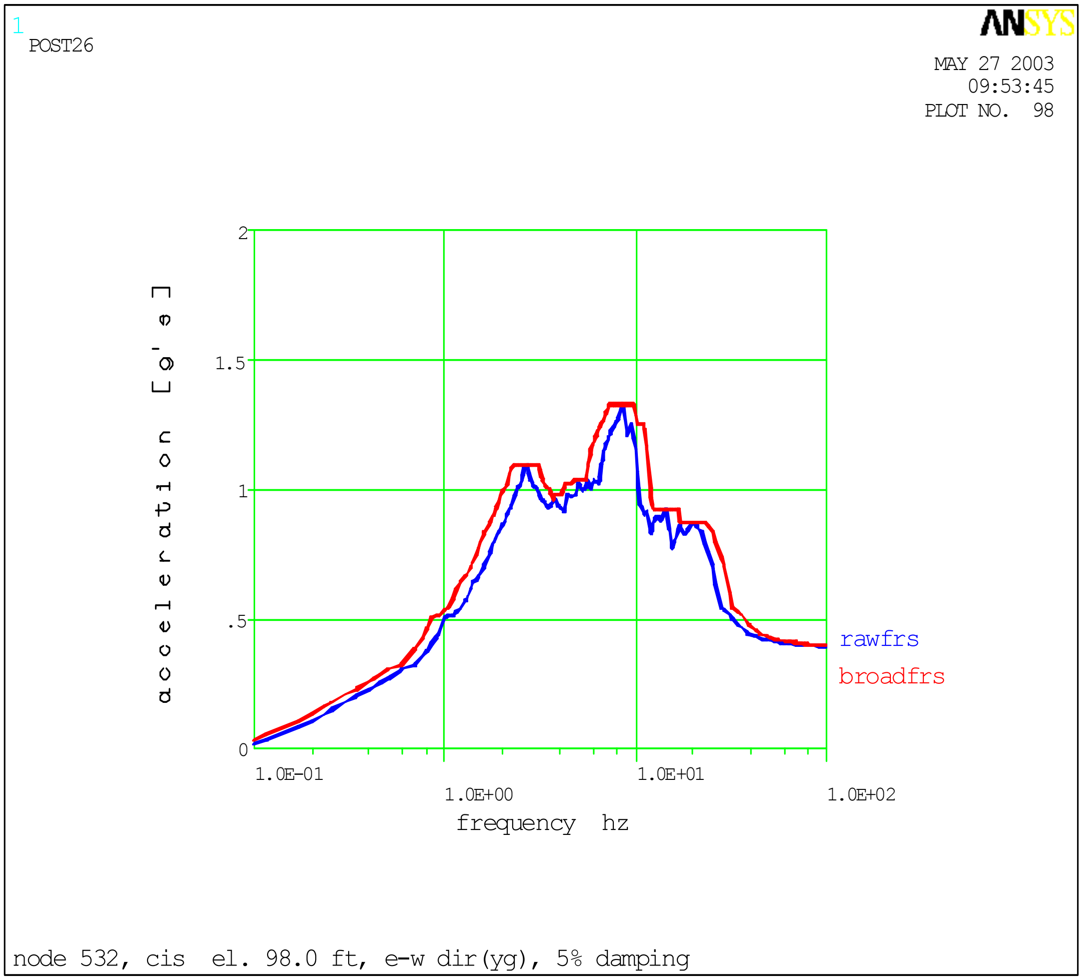


Figure 3.7.2-17 (Sheet 2 of 9)

Containment Internal Structures SSE Floor Response Spectra

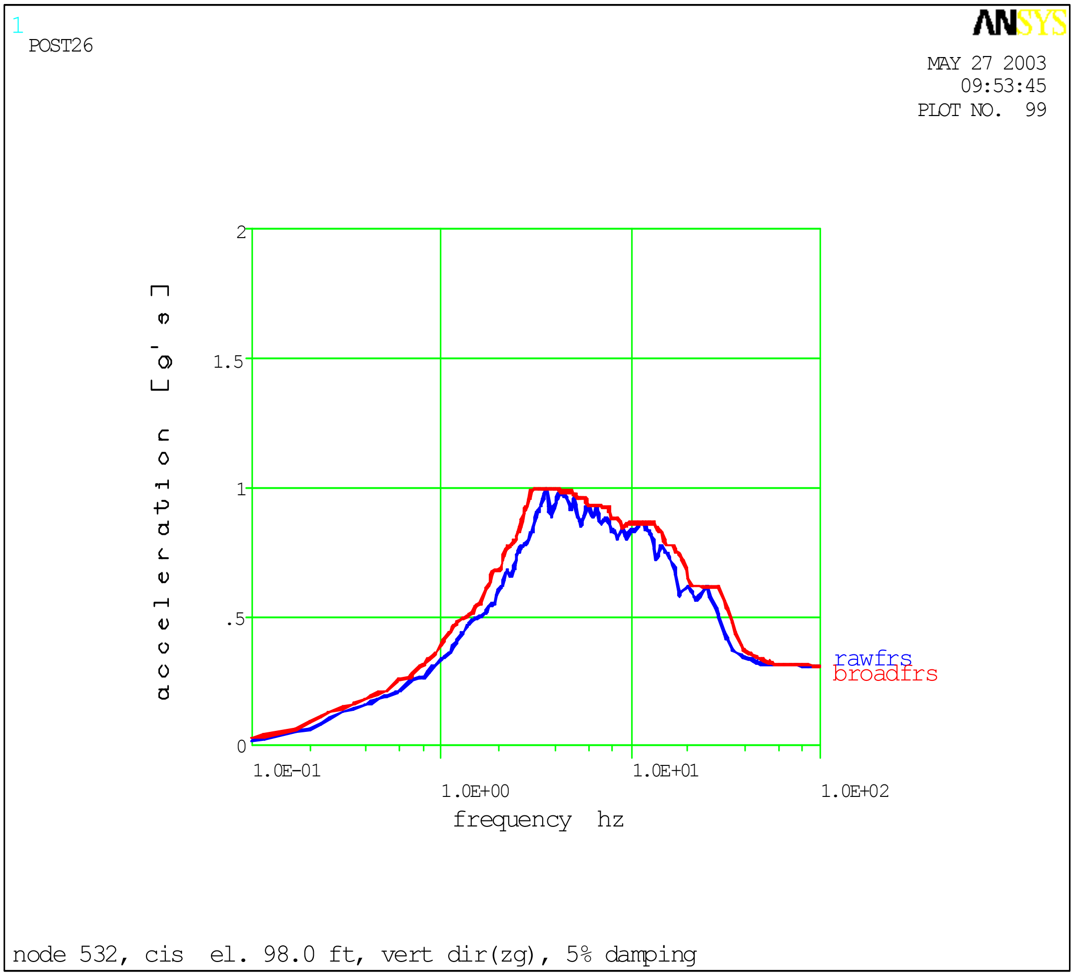


Figure 3.7.2-17 (Sheet 3 of 9)

Containment Internal Structures SSE Floor Response Spectra

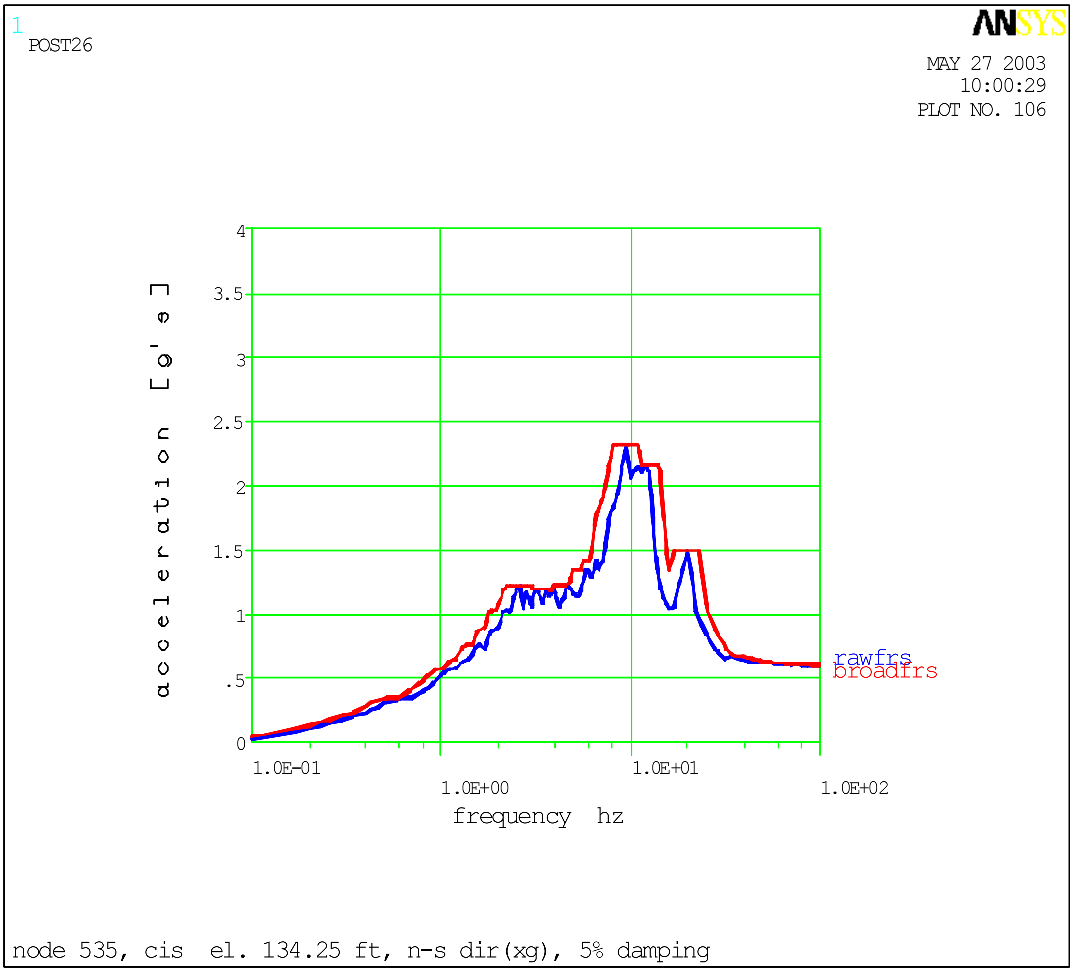


Figure 3.7.2-17 (Sheet 4 of 9)

Containment Internal Structures SSE Floor Response Spectra

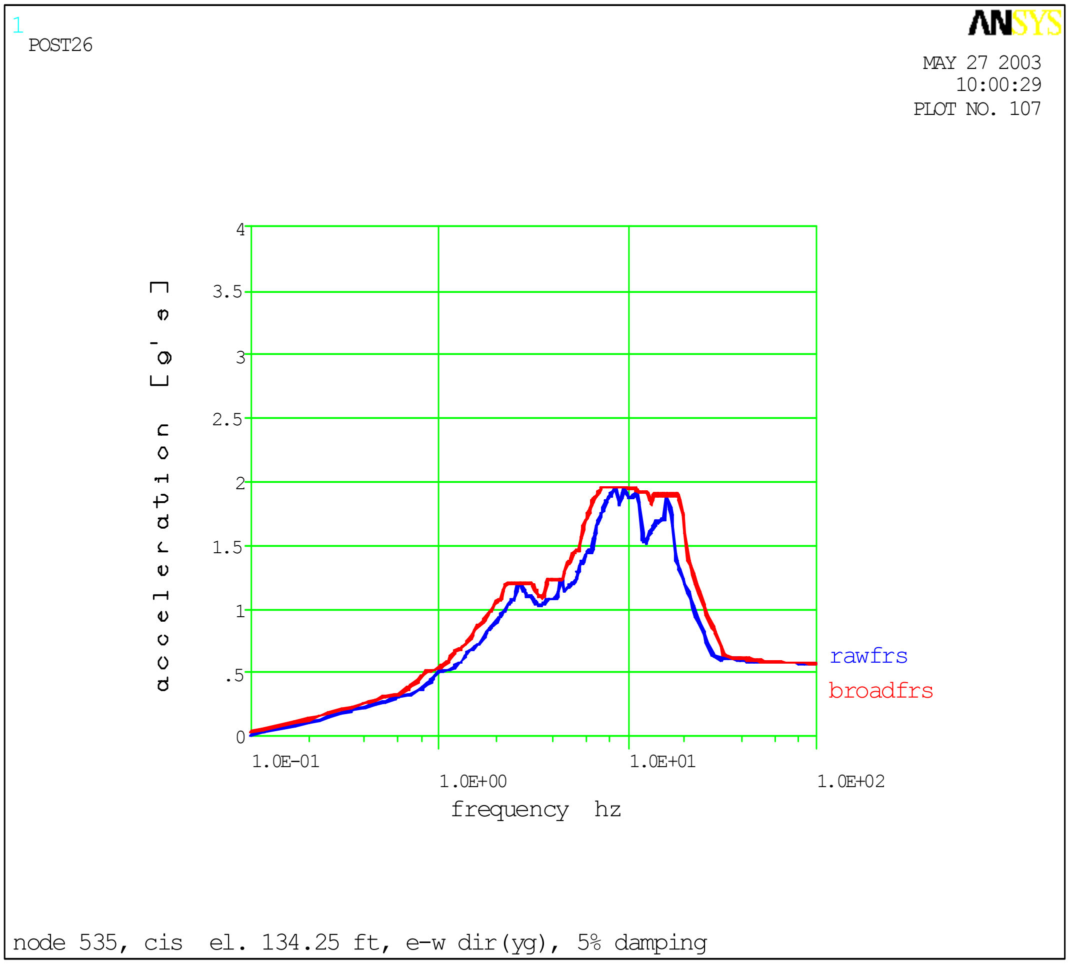


Figure 3.7.2-17 (Sheet 5 of 9)

Containment Internal Structures SSE Floor Response Spectra

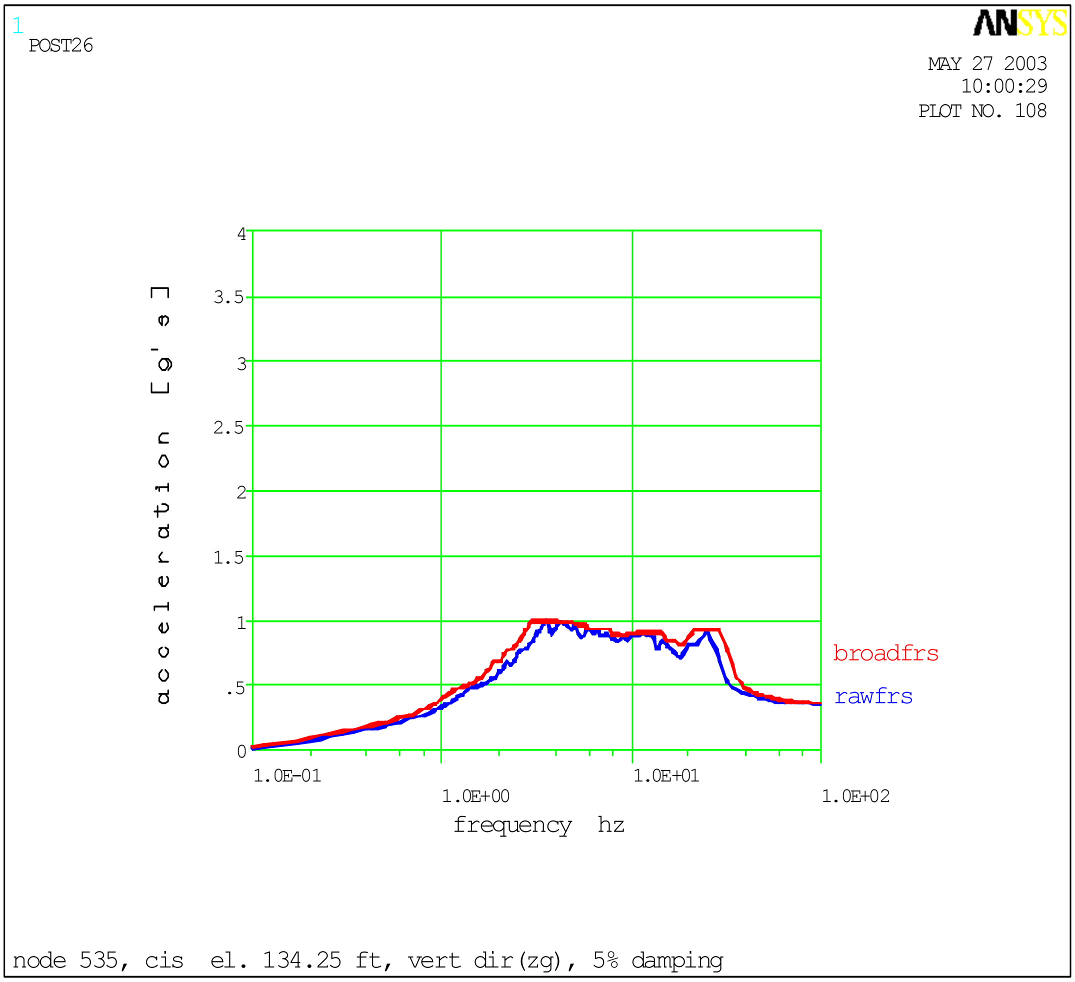


Figure 3.7.2-17 (Sheet 6 of 9)

Containment Internal Structures SSE Floor Response Spectra

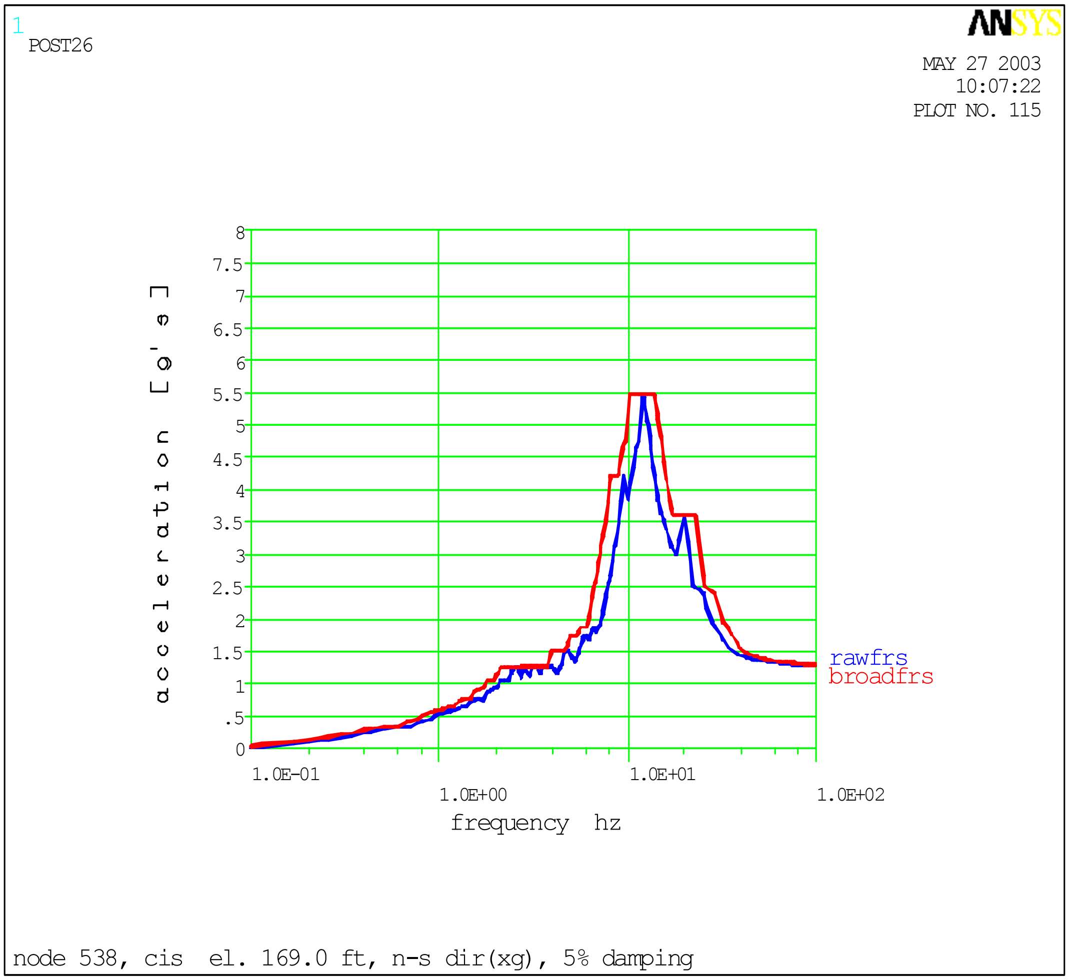


Figure 3.7.2-17 (Sheet 7 of 9)

Containment Internal Structures SSE Floor Response Spectra

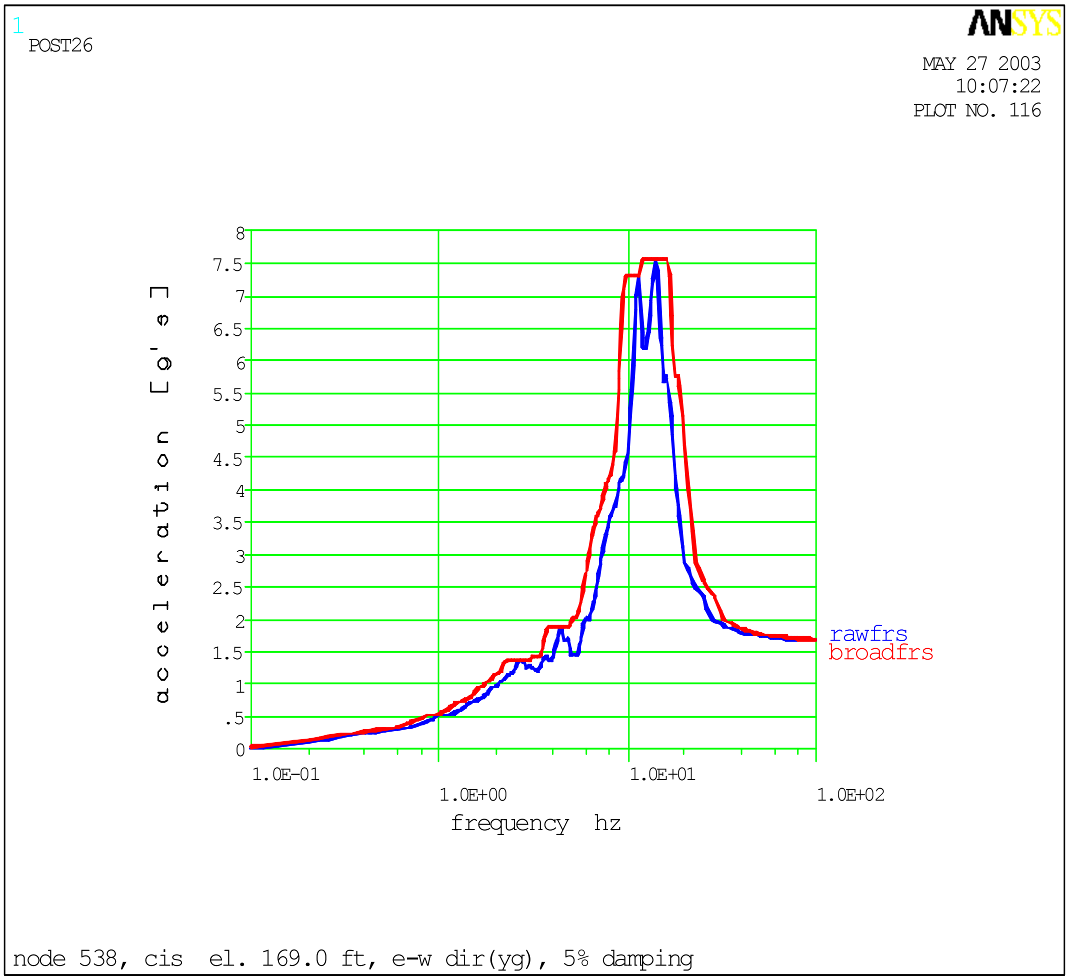


Figure 3.7.2-17 (Sheet 8 of 9)

Containment Internal Structures SSE Floor Response Spectra

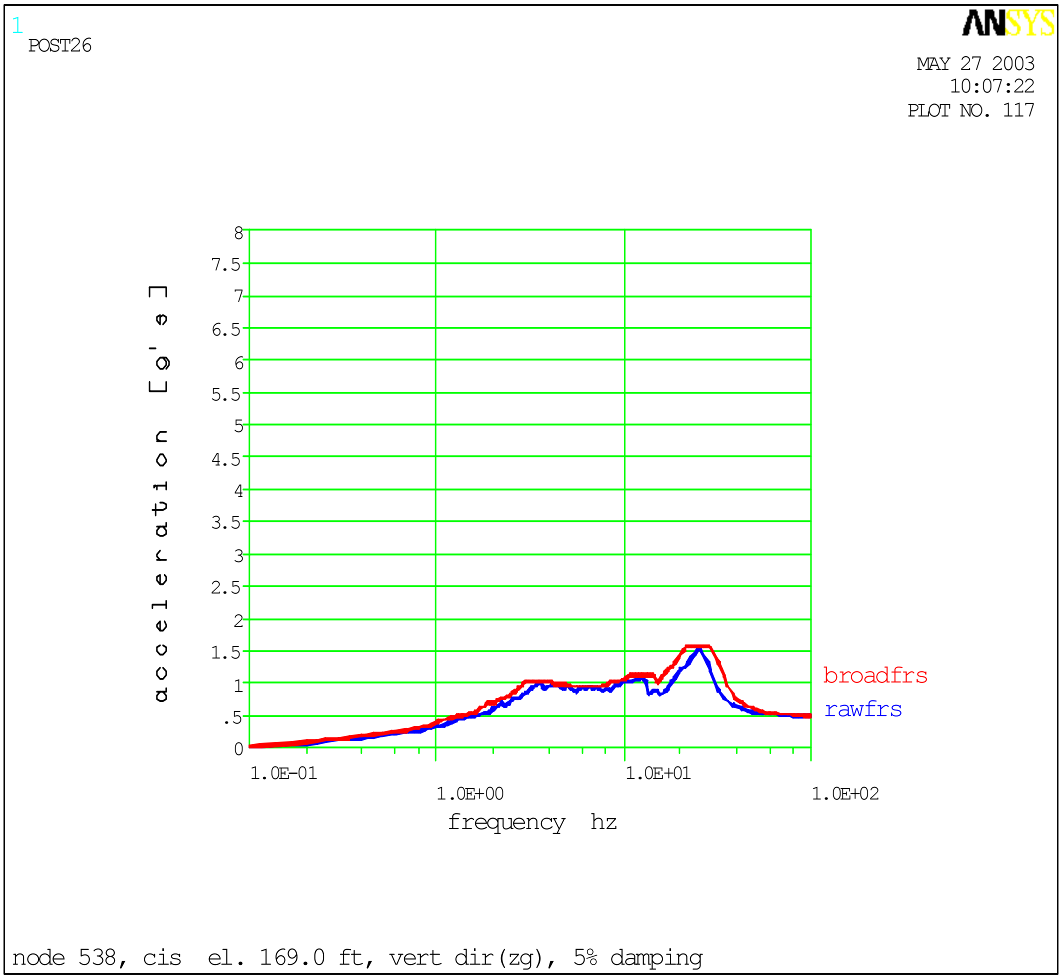


Figure 3.7.2-17 (Sheet 9 of 9)

Containment Internal Structures SSE Floor Response Spectra

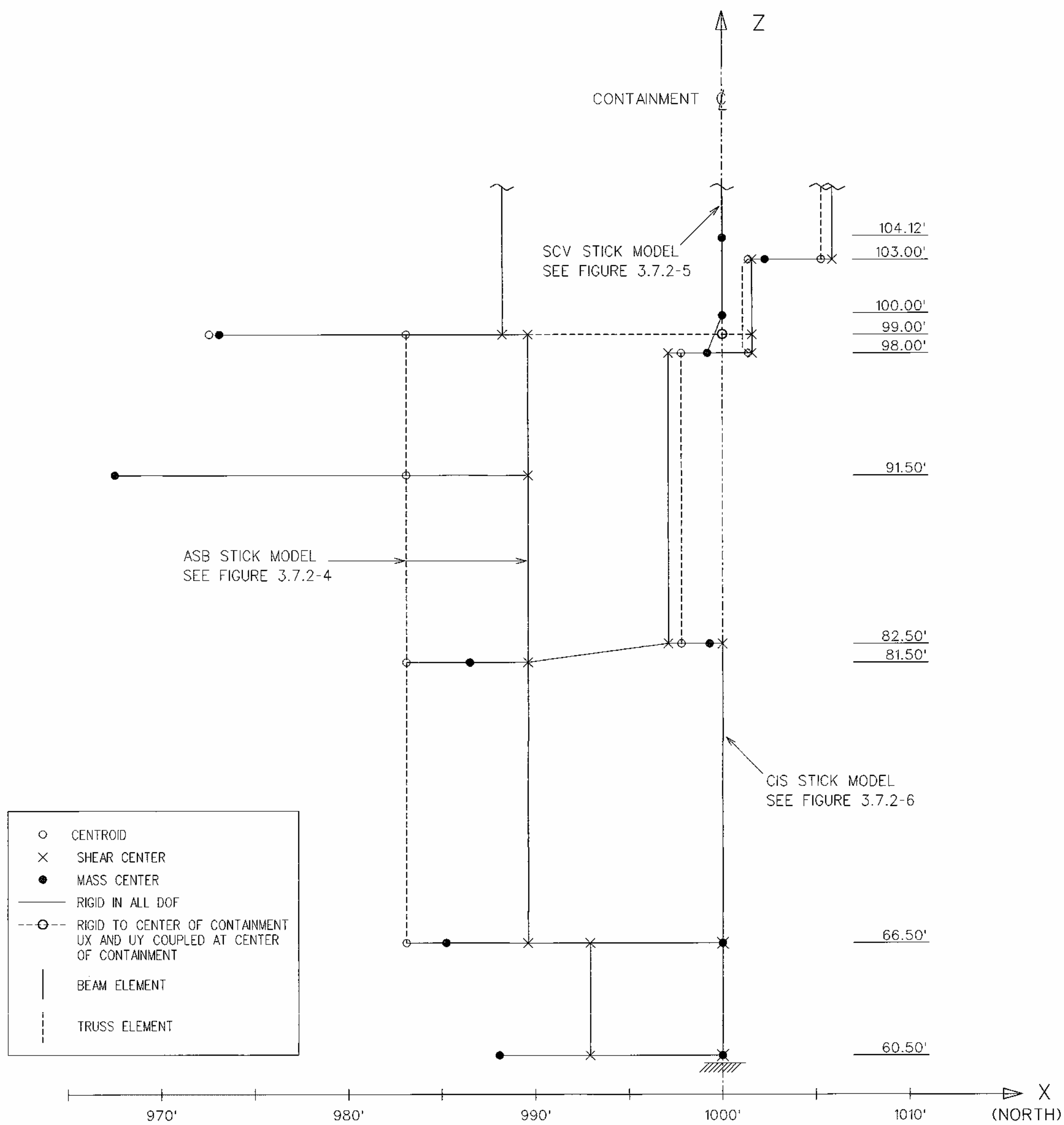


Figure 3.7.2-18

Connection Between Lumped Mass Stick Model – Fixed Base Analysis

[This page intentionally blank]

Withheld under 10 CFR 2.390.

Figure 3.7.2-19 (Sheet 1 of 10)

Annex Building Key Structural Dimensions
Plan at Elevation 100′-0″

Withheld under 10 CFR 2.390.

Figure 3.7.2-19 (Sheet 2 of 10)

**Annex Building Key Structural Dimensions
Plan at Elevation 107′-2″ and 117′-6″**

Withheld under 10 CFR 2.390.

Figure 3.7.2-19 (Sheet 3 of 10)

Annex Building Key Structural Dimensions
Plan at Elevation 135′-3″

Withheld under 10 CFR 2.390.

Figure 3.7.2-19 (Sheet 4 of 10)

**Annex Building Key Structural Dimensions
Plan at Elevation 158′-0″ and 146′-3″**

Withheld under 10 CFR 2.390.

Figure 3.7.2-19 (Sheet 5 of 10)

Annex Building Key Structural Dimensions
Roof Plan at Elevation 154′-0″ and 181′-11 3/4″

Withheld under 10 CFR 2.390.

Figure 3.7.2-19 (Sheet 6 of 10)

**Annex Building Key Structural Dimensions
Section A - A**

Withheld under 10 CFR 2.390.

Figure 3.7.2-19 (Sheet 7 of 10)

**Annex Building Key Structural Dimensions
Section B - B**

Withheld under 10 CFR 2.390.

Figure 3.7.2-19 (Sheet 8 of 10)

Annex Building Key Structural Dimensions
Section C - C

Withheld under 10 CFR 2.390.

Figure 3.7.2-19 (Sheet 9 of 10)

Annex Building Key Structural Dimensions
Sections D - D, E - E, & F - F

Withheld under 10 CFR 2.390.

Figure 3.7.2-19 (Sheet 10 of 10)

Annex Building Key Structural Dimensions
Sections G - G, H - H, & J - J

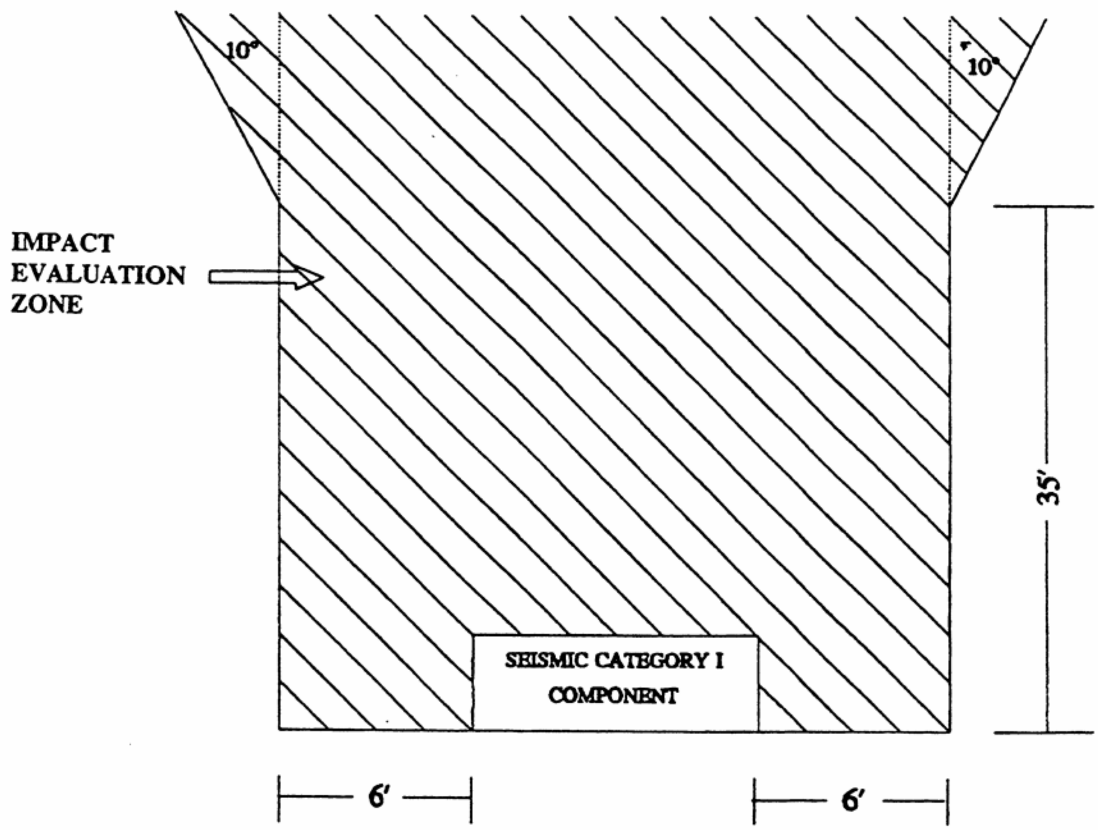


Figure 3.7.3-1

Impact Evaluation Zone

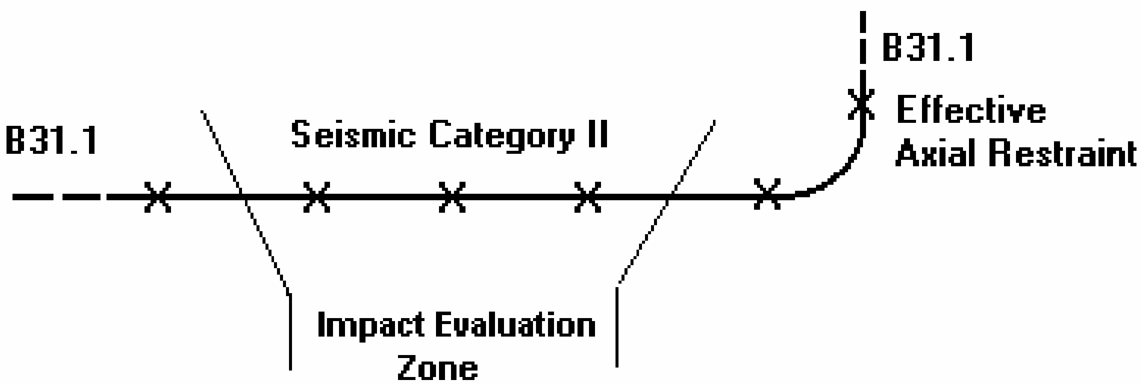


Figure 3.7.3-2

Impact Evaluation Zone and Seismic Supported Piping

3.8 Design of Category I Structures

3.8.1 Concrete Containment

This subsection is not applicable to the AP1000.

3.8.2 Steel Containment

3.8.2.1 Description of the Containment

3.8.2.1.1 General

This subsection describes the structural design of the steel containment vessel and its parts and appurtenances. The steel containment vessel is an integral part of the containment system whose function is described in Section 6.2. It serves both to limit releases in the event of an accident and to provide the safety-related ultimate heat sink.

The containment vessel is an ASME metal containment. The information contained in this subsection is based on the design specification and preliminary design and analyses of the vessel. Final detailed analyses will be documented in the ASME Design Report.

The containment arrangement is indicated in the general arrangement figures in Section 1.2. The portion of the vessel above elevation 132′-3″ is surrounded by the shield building but is exposed to ambient conditions as part of the passive cooling flow path. A flexible watertight and airtight seal is provided at elevation 132′-3″ between the containment vessel and the shield building. The portion of the vessel below elevation 132′-3″ is fully enclosed within the shield building.

Figure 3.8.2-1 shows the containment vessel outline, including the plate configuration and crane girder. It is a free-standing, cylindrical steel vessel with ellipsoidal upper and lower heads. [*The containment vessel has the following design characteristics:*

Diameter: 130 feet
Height: 215 feet 4 inches
Design Code: ASME III, Div. 1
Material: SA738, Grade B
Design Pressure: 59 psig
Design Temperature: 300°F
Design External Pressure: 2.9 psid

The wall thickness in most of the cylinder is 1.75 inches. The wall thickness of the lowest course of the cylindrical shell is increased to 1.875 inches to provide margin in the event of corrosion in the embedment transition region. The thickness of the heads is 1.625 inches.]* The heads are ellipsoidal with a major diameter of 130 feet and a height of 37 feet, 7.5 inches.

The containment vessel includes the shell, hoop stiffeners and crane girder, equipment hatches, personnel airlocks, penetration assemblies, and miscellaneous appurtenances and attachments. The design for external pressure is dependent on the spacing of the hoop stiffeners and crane girder, which are shown on Figure 3.8.2-1. [*The spacing between each pair of ring supports (the bottom*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

flange of the crane girder, the hoop stiffeners, and the concrete floor at elevation 100′-0″) is less than 50 feet, 6 inches.]*

The polar crane is designed for handling the reactor vessel head during normal refueling. The crane girder and wheel assemblies are designed to support a special trolley to be installed in the event of steam generator replacement.

The containment vessel supports most of the containment air baffle as described in subsection 3.8.4. The air baffle is arranged to permit inspection of the exterior surface of the containment vessel. Steel plates are welded to the dome as part of the water distribution system, described in subsection 6.2.2. The polar crane system is described in subsection 9.1.5.

3.8.2.1.2 Containment Vessel Support

The bottom head is embedded in concrete, with concrete up to elevation 100′ on the outside and to the maintenance floor at elevation 107′-2″ on the inside. The containment vessel is assumed as an independent, free-standing structure above elevation 100′. The thickness of the lower head is the same as that of the upper head. There is no reduction in shell thickness even though credit could be taken for the concrete encasement of the lower head.

Vertical and lateral loads on the containment vessel and internal structures are transferred to the basemat below the vessel by shear studs, friction, and bearing. The shear studs are not required for design basis loads. They provide additional margin for earthquakes beyond the safe shutdown earthquake.

Seals are provided at the top of the concrete on the inside and outside of the vessel to prevent moisture between the vessel and concrete. A typical cross section design of the seal is presented in Figure 3.8.2-8, sheets 1 and 2.

3.8.2.1.3 Equipment Hatches

Two equipment hatches are provided. One is at the operating floor (elevation 135′-3″) with an inside diameter of 16 feet. The other is at floor elevation 107′-2″ to permit grade-level access into the containment, with an inside diameter of 16 feet. The hatches, shown in Figure 3.8.2-2, consist of a cylindrical sleeve with a pressure seated dished head bolted on the inside of the vessel. The containment internal pressure acts on the convex face of the dished head and the head is in compression. The flanged joint has double O-ring or gum-drop seals with an annular space that may be pressurized for leak testing the seals. Each of the two equipment hatches is provided with an electrically powered hoist and with a set of hardware, tools, equipment and a self-contained power source for moving the hatch from its storage location and installing it in the opening.

3.8.2.1.4 Personnel Airlocks

Two personnel airlocks are provided, one located adjacent to each of the equipment hatches. Figure 3.8.2-3 shows the typical arrangement. Each personnel airlock has about a 10-foot external diameter to accommodate a door opening of width 3 feet 6 inches and height 6 feet 8 inches. The airlocks are long enough to provide a clear distance of 8 feet, which is not impaired by the swing

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

of the doors within the lock. The airlocks extend radially out from the containment vessel through the shield building. They are supported by the containment vessel.

Each airlock has two double-gasketed, pressure-seated doors in series. The doors are mechanically interlocked to prevent simultaneous opening of both doors and to allow one door to be completely closed before the second door can be opened. The interlock can be bypassed by using special tools and procedures.

3.8.2.1.5 Mechanical Penetrations

The mechanical penetrations consist of the fuel transfer penetration and mechanical piping penetrations and are listed in Table 6.2.3-4.

Figure 3.8.2-4, sheet 1, shows typical details for the main steam penetration. This includes bellows to minimize piping loads applied to the containment vessel and a guardpipe to protect the bellows and to prevent overpressurization of the containment annulus in a postulated pipe rupture event. Similar details are used for the feedwater penetration.

Figure 3.8.2-4, sheet 2, shows typical details for the startup feedwater penetration. This includes a guardpipe to prevent overpressurization of the containment annulus in a postulated pipe rupture event. Similar details are used for the steam generator blowdown penetration.

Figure 3.8.2-4, sheet 3, shows typical details for the normal residual heat removal penetration. Similar details are used for other penetrations below elevation 107′-2″ where there is concrete inside the containment vessel. The flued head is integral with the process piping and is welded to the containment sleeve. The welds are accessible for in-service inspection. The containment sleeve is separated from the concrete by compressible material.

Figure 3.8.2-4, sheet 4 shows typical details for the other mechanical penetrations. These consist of a sleeve welded to containment with either a flued head welded to the sleeve (detail A), or with the process piping welded directly to the sleeve (detail B). Flued heads are used for stainless piping greater than 2 inches in nominal diameter and for piping with high operating temperatures.

Design requirements for the mechanical penetrations are as follows:

- Design and construction of the process piping follow ASME, Section III, Subsection NC. Design and construction of the remaining portions follow ASME Code, Section III, Subsection NE. The boundary of jurisdiction is according to ASME Code, Section III, Subsection NE.
- Penetrations are designed to maintain containment integrity under design basis accident conditions, including pressure, temperature, and radiation.
- Guard pipes are designed for pipe ruptures as described in subsection 3.6.2.1.1.4.
- Bellows are stainless steel or nickel alloy and are designed to accommodate axial and lateral displacements between the piping and the containment vessel. These displacements include

thermal growth of the main steam and feedwater piping during plant operation, relative seismic movements, and containment accident and testing conditions. Cover plates are provided to protect the bellows from foreign objects during construction and operation. These cover plates are removable to permit in-service inspection.

The fuel transfer penetration, shown in Figure 3.8.2-4, sheet 5, is provided to transfer fuel between the containment and the fuel handling area of the auxiliary building. The fuel transfer tube is welded to the penetration sleeve. The containment boundary is a double-gasketed blind flange at the refueling canal end. The expansion bellows are not a part of the containment boundary. Rather, they are water seals during refueling operations and accommodate differential movement between the containment vessel, containment internal structures, and the auxiliary building.

3.8.2.1.6 Electrical Penetrations

Figure 3.8.2-4, sheet 6, shows a typical 12-inch-diameter electrical penetration. The penetration assemblies consist of three modules (or six modules in a similar 18-inch-diameter penetration) passing through a bulkhead attached to the containment nozzle. Electrical design of these penetrations is described in subsection 8.3.1.1.5.

Electrical penetrations are designed to maintain containment integrity under design basis accident conditions, including pressure, temperature, and radiation. Double barriers permit testing of each assembly to verify that containment integrity is maintained. Design and testing is according to IEEE Standard 317-83 and IEEE Standard 323-74.

3.8.2.2 Applicable Codes, Standards, and Specifications

[*The containment vessel is designed and constructed according to the 2001 edition of the ASME Code, Section III, Subsection NE, Metal Containment, including the 2002 Addenda. Stability of the containment vessel and appurtenances is evaluated using ASME Code, Case N-284-1, Metal Containment Shell Buckling Design Methods, Class MC, Section III, Division 1, as published in the 2001 Code Cases, 2001 Edition, July 1, 2001.*]*

Structural steel nonpressure parts, such as ladders, walkways, and handrails are designed to the requirements for steel structures defined in subsection 3.8.4.

Section 1.9 discusses compliance with the Regulatory Guides and the Standard Review Plans.

3.8.2.3 Loads and Load Combinations

Table 3.8.2-1 summarizes the design loads, load combinations and ASME Service Levels. They meet the requirements of the ASME Code, Section III, Subsection NE. The containment vessel is designed for the following loads specified during construction, test, normal plant operation and shutdown, and during accident conditions:

D Dead loads or their related internal moments and forces, including any permanent piping and equipment loads

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- L Live loads or their related internal moments and forces, including crane loads
- P_o Operating pressure loads during normal operating conditions resulting from pressure variations either inside or outside containment
- T_o Thermal effects and loads during normal operating conditions, based on the most critical transient or steady-state condition
- R_o Piping and equipment reactions during normal operating conditions, based on the most critical transient or steady-state condition
- W Loads generated by the design wind on the portion of the containment vessel above elevation 132′, as described in subsection 3.3.1.1
- E_s Loads generated by the safe shutdown earthquake (SSE) as described in Section 3.7
- W_t Loads generated by the design tornado on the portion of the containment vessel above elevation 132′, as described in subsection 3.3.2
- P_t Test pressure
- P_d Containment vessel design pressure that exceeds the pressure load generated by the postulated pipebreak accidents and passive cooling function
- P_e Containment vessel external pressure
- T_a Thermal loads under thermal conditions generated by the postulated break or passive cooling function and including T_o. This includes variations around the shell due to the surrounding buildings and maldistribution of the passive containment cooling system water.
- R_a Piping and equipment reactions under thermal conditions generated by the postulated break, as described in Section 3.6, and including R_o
- Y_r Loads generated by the reaction on the broken high-energy pipe during the postulated break, as described in Section 3.6
- Y_j Jet impingement load on a structure generated by the postulated break, as described in Section 3.6
- Y_m Missile impact load on a structure generated by or during the postulated break, as from pipe whipping, as described in Section 3.6

Note that loads associated with flooding of the containment below elevation 107′ are resisted by the concrete structures and not by the containment vessel.

3.8.2.4 Design and Analysis Procedures

The design and analysis procedures for the containment vessel are according to the requirements of the ASME Code, Section III, Subsection NE.

The analyses are summarized in Table 3.8.2-4. The detailed analyses will use a series of general-purpose finite element, axisymmetric shell and special purpose computer codes to conduct such analyses. Code development, verification, validation, configuration control, and error reporting and resolution are according to the Quality Assurance requirements of Chapter 17.

3.8.2.4.1 Analyses for Design Conditions

3.8.2.4.1.1 Axisymmetric Shell Analyses

The containment vessel is modelled as an axisymmetric shell and analyzed using the ANSYS computer program. A model used for static analyses is shown in Figure 3.8.2-6.

Dynamic analyses of the axisymmetric model, which is similar to that shown in Figure 3.8.2-6, are performed to obtain frequencies and mode shapes. These are used to confirm the adequacy of the containment vessel stick model as described in subsection 3.7.2.3.2. Static stress analyses are performed for each of the following loads:

- Dead load
- Internal pressure
- Equivalent static seismic accelerations
- Polar crane wheel loads
- Wind loads
- Thermal loads

The equivalent static accelerations applied in the seismic analysis are the maximum acceleration responses based on the results for the hard rock site shown in Table 3.7.2-6. These accelerations are applied as separate load cases in the east-west, north-south, and vertical directions. The torsional moments, which include the effects of the eccentric masses, are increased to account for accidental torsion and are evaluated in a separate calculation.

The results of these load cases are factored and combined in accordance with the load combinations identified in Table 3.8.2-1. These results are used to evaluate the general shell away from local penetrations and attachments, that is, for areas of the shell represented by the axisymmetric geometry. The results for the polar crane wheel loads are also used to establish local shell stiffnesses for inclusion in the containment vessel stick model described in subsection 3.7.2.3. The results of the analyses and evaluations are included in the containment vessel design report.

Design of the containment shell is primarily controlled by the internal pressure of 59 psig. The meridional and circumferential stresses for the internal pressure case are shown in Figure 3.8.2-5. The most highly stressed regions for this load case are the portions of the shell away from the

hoop stiffeners and the knuckle region of the top head. In these regions the stress intensity is close to the allowable for the design condition.

Major loads that induce compressive stresses in the containment vessel are internal and external pressure and crane and seismic loads. Each of these loads and the evaluation of the compressive stresses are discussed below.

- Internal pressure causes compressive stresses in the knuckle region of the top head and in the equipment hatch covers. The evaluation methods are similar to those discussed in subsection 3.8.2.4.2 for the ultimate capacity.
- Evaluation of external pressure loads is performed in accordance with ASME Code, Section III, Subsection NE, Paragraph NE-3133.
- Crane wheel loads due to crane dead load, live load, and seismic loads result in local compressive stresses in the vicinity of the crane girder. These are evaluated in accordance with ASME Code, Case N-284.
- Overall seismic loads result in axial compression and tangential shear stresses at the base of the cylindrical portion. These are evaluated in accordance with ASME Code, Case N-284.

The bottom head is embedded in the concrete base at elevation 100 feet. This leads to circumferential compressive stresses at the discontinuity under thermal loading associated with the design basis accident. The containment vessel design includes a Service Level A combination in which the vessel above elevation 107′-2″ is specified at the design temperature of 300°F and the portion of the embedded vessel (and concrete) below elevation 100 feet is specified at a temperature of 70°F. The temperature profile for the vessel is linear between these elevations. Containment shell buckling close to the base is evaluated against the criteria of ASME Code, Case N-284.

Revision 1 of Code Case N-284 is used for the evaluation of the containment shell and equipment hatches.

3.8.2.4.1.2 Local Analyses

The penetrations and penetration reinforcements are designed in accordance with the rules of ASME III, Subsection NE. The design of the large penetrations for the two equipment hatches and the two airlocks use the results of finite element analyses which consider the effect of the penetration and its dynamic response as follows:

1. The upper airlock and equipment hatch penetrations are modeled in individual finite element models. The lower airlock and equipment hatch are modeled in a combined finite element model (Figure 3.8.2-7) including the boundary conditions representing the embedment. The finite element models include a portion of the shell sufficient that the boundary conditions do not affect the results of the local analyses.

2. Surface loads are applied for pressure and inertia loads on the shell included in the model. Loads corresponding to the stresses in the unpenetrated vessel at the location of the penetration, obtained from the axisymmetric analyses described in the previous subsection, are applied as boundary conditions for the local finite element models.

3. The out-of-plane stiffness of the containment vessel is determined for unit radial loads and moments at the location of the penetration. The frequency of the local radial and rotational modes are calculated using single degree of freedom models with mass and rotational inertias of the penetration. Seismic response accelerations for the radial and rotational modes are determined from the applicable floor response spectra for the containment vessel. Equivalent static radial loads and moments are calculated from these seismic response accelerations.

4. Radial loads and moments due to the local seismic response and due to external loads on the penetration are applied statically at the location of the penetration. These loads are applied individually corresponding to the three directions of input (radial, tangential and vertical). The three directions of seismic input are combined by the square root sum of the squares method or by the 100%, 40%, 40% method as described in subsection 3.7.2.6.

5. Stresses due to local loads on the penetration (step 4) are combined with those from the global vessel analyses (step 2). Stresses are evaluated against the stress intensity criteria of ASME Section III, Subsection NE. Stability is evaluated against ASME Code Case N-284. Local stresses in the regions adjacent to the major penetrations are evaluated in accordance with paragraph 1711 of the code case. Stability is not evaluated in the reinforced penetration neck and insert plate which are substantially stiffer than the adjacent shell.

The final design of containment vessel elements (reinforcement) adjacent to concentrated masses (penetrations) is completed by the Combined License applicant and documented in the ASME Code design report.

The 16 foot diameter equipment hatch located at elevation 112′-6″ and the personnel airlock located at elevation 110′-6″ are in close proximity to each other and to the concrete embedment. Design of these penetrations uses the finite element model shown in Figure 3.8.2-7. Static analyses are performed for dead loads and containment pressure. Response spectrum analyses are performed for seismic loads. Stresses are evaluated as described for the single penetrations in step 5 above.

Finite element analyses are performed to confirm that the design of the penetration in accordance with the ASME code provides adequate margin against buckling. A finite element ANSYS model, as shown in Figure 3.8.2-7, represents the portion of the vessel close to the embedment with the lower equipment hatch and personnel airlock. This is analyzed for external pressure and axial loads and demonstrates that the penetration reinforcement is sufficient and precludes buckling close to the penetrations. The lowest buckling mode occurs in the shell away from the penetrations and embedment.

3.8.2.4.2 Evaluation of Ultimate Capacity

The capacity of the containment vessel has been calculated for internal pressure loads for use in the probabilistic risk assessment analyses and severe accident evaluations. Each element of the containment vessel boundary was evaluated to estimate the maximum pressure at an ambient temperature of 100°F corresponding to the following stress and buckling criteria:

- Deterministic severe accident pressure capacity corresponding to ASME Service Level C limits on stress intensity, ASME paragraph NE-3222, and ASME Code Case N-284 for buckling of the equipment hatch covers, and 60 percent of critical buckling for the top head. The deterministic severe accident pressure capacity corresponds to the approach in SECY 93-087, to maintain a reliable leak-tight barrier approximately 24 hours following the onset of core damage under the more likely severe accident challenges. This approach was approved by the Nuclear Regulatory Commission as outline in the Staff Requirements Memorandum on SECY-93-087 - Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light Water Reactor (ALWR) Designs, Dated July 21, 1993.

- Best estimate capacity corresponding to gross membrane yield at the ASME-specified minimum yield stress (SA738, Grade B, yield stress = 60 ksi, ultimate stress = 85 ksi), and critical buckling for the equipment hatch covers and top head.

The results are shown in Table 3.8.2-2. The analyses at a temperature of 100°F are described in the following paragraphs for each element. The critical regions identified in this table are then examined further for their response at higher temperatures. This results in the best-estimate capacity based on the ASME-specified minimum yield properties. The evaluation considered the containment boundary elements including:

- Cylindrical shell
- Top and bottom heads
- Equipment hatches and covers
- Personnel airlocks
- Mechanical and electrical penetrations

The evaluation identified the most likely failure mode to be that associated with gross yield of the cylindrical shell. Loss of containment function would be expected to occur because the large post-yield deflections would lead to local failures at penetrations, bellows, or other local discontinuities.

3.8.2.4.2.1 Tensile Stress Evaluation of Shell

Results of the axisymmetric analyses of the cylinder and top head described in subsection 3.8.2.4.1 for dead load and internal pressure were evaluated to determine the pressure at which stresses reach yield at an ambient temperature of 100°F. The analyses assume the shell is fixed at elevation 100′, where the bottom head is embedded in concrete. The steel bottom head is identical to the top head and has a pressure capability greater than the top head due to the additional strength of the embedment concrete.

The allowable stress intensity under Service Level C loads is equal to yield. This corresponds to an internal pressure of 135 psig. The critical section is the cylinder, where the general primary membrane stress intensity is greatest.

The best-estimate yield analysis uses the von Mises criterion to establish yield rather than the more conservative ASME stress intensity approach. This increases the yield stress by about 15 percent for the cylinder, where the longitudinal stress is equal to one-half of the hoop stress resulting in first yield at an internal pressure of 155 psig. At this pressure, hoop stresses in the cylinder reach yield. The radial deflection is about 1.6 inches. As pressure increases further, large deflections occur. For a material such as SA738, where the yield plateau extends from a strain of 0.2 percent to 0.6 percent, deflections would increase to 4.8 inches at yield without a substantial increase in pressure. Strain hardening would then permit a further increase in pressure with large radial deflections, as described in subsection 3.8.2.4.2.6.

3.8.2.4.2.2 Buckling Evaluation of Top Head

The top head has a radius-to-height ratio of 1.728. This is not as shallow as most ellipsoidal or torispherical heads, which typically have a radius-to-height ratio of 2. The ratio was specifically selected to minimize the local stresses and buckling in the knuckle region due to internal pressure. As the ratio decreases, the magnitude of compressive stresses in the knuckle region decreases; for a radius-to-height ratio of 1.4 or smaller, there are no compressive stresses and therefore there is no potential for buckling.

Theoretical Buckling Capacity

The top head was analyzed using the BOSOR-5 computer code (Reference 1). This code permits consideration of both large displacements and nonlinear material properties. It calculates shell stresses and checks stability at each load step. The analysis included a portion of the cylinder with a thickness of 1.625 inches. In this analysis, yield of the cylinder started at a pressure of 144 psig using elastic – perfectly plastic material properties, a yield stress of 60 ksi, and the von Mises yield criterion. Yield of the top of the crown started at an internal pressure of 146 psig. Yield of the knuckle region started at 152 psig. A theoretical plastic buckling pressure of 174 psig was determined. At this pressure, the maximum effective prebuckling strain was 0.23 percent in the knuckle region where buckling occurred and 2.5 percent at the crown. The maximum deflection at the crown was 15.9 inches. A similar analysis was performed using nonlinear material properties considering the effects of residual stresses; buckling did not occur in this analysis, and failure would occur once strains at the crown reach ultimate. The failure mode was found to be an axisymmetric plastic collapse resulting from excessive vertical displacements at the crown. The maximum displacement was 43 inches at 195 psig.

Predicted Pressure Capacity

The actual buckling capacity may be lower than the theoretical buckling capacity because of effects not included in the analysis such as imperfections and residual stresses. This is considered by the use of capacity reduction factors that are based upon a correlation of theory and experiment. The capacity reduction factor for the top head was evaluated based on comparisons of BOSOR-5 analyses against test results of ellipsoidal and torispherical heads. This evaluation is described

below and concludes that no reduction in capacity need be considered; that is, a capacity reduction factor of 1.0 is appropriate.

The knuckle region of ellipsoidal and torispherical heads is subjected to meridional tension and circumferential compression. The meridional tension tends to stabilize the knuckle region and reduces its sensitivity to imperfection. The radius-to-height ratio of 1.728 of the AP1000 head results in a larger ratio of meridional tension to circumferential compression than on shallower heads, further reducing the sensitivity to imperfection.

Welding Research Council Bulletin 267 (Reference 22) shows a comparison of BOSOR-5 predictions of buckling against the results of 20 tests of small head models. These results are summarized in Table 4 of the reference and show ratios (capacity reduction factors) of actual buckling to the BOSOR-5 prediction with an average of 1.2. Only one of the 20 cases shows a capacity reduction factor less than 1.0.

Table 3.8.2-3 shows the key parameters, test results, and BOSOR-5 predictions for two large, fabricated 2:1 torispherical heads tested and reported in NUREG/CR-4926 (Reference 23). The theoretical plastic buckling pressure predicted by BOSOR-5 represents initial buckling based on actual material properties. The initial buckling did not cause failure for either of the tests, and test pressure continued to increase until rupture occurred in the spherical cap. The collapse pressures were three to four times the initial buckling pressures.

- **Test Head 1** – The test result of 58 psig is 79 percent of the predicted theoretical plastic buckling pressure of 74 psig. Many of the buckles occurred directly on the meridional weld seams of the knuckle. The knuckle welds were noticeably flatter than the corresponding welds of the Test 2 head. The as-built configuration extended inside the theoretical shape at some of the meridional weld seams and was most pronounced at the location of the first observed buckle. Model 1 exceeded the tolerances for formed heads specified for containment vessels in NE-4222.2 of ASME, Section III, Subsection NE.

- **Test Head 2** – The test result of 106 psi is 100 percent of the BOSOR-5 predicted theoretical plastic buckling pressure. For test head 2, the welds had no noticeable flat spots and there was a smooth transition between the sphere and knuckle sections. Test head 2 was well within the Code allowable deviations.

The low-capacity reduction factor of 0.79 for test head 1 is attributed to excessive imperfections associated with the fabrication of relatively thin plate (0.196 inch). These imperfections were visible and were outside the tolerances permitted by the ASME Code. The results of test head 1 are therefore not considered applicable to the AP1000. The results of test head 2 and of the small-scale models described in the Welding Research Council Bulletin support the application of a capacity reduction factor of 1.0.

The capacity of the AP1000 head was also investigated using an approach similar to that permitted in ASME Code, Case N284. This code case provides alternate rules for certain containment vessel geometries such as cylindrical shells. The theoretical elastic buckling pressure was calculated to be 536 psi using the linear elastic computer code, BOSOR-4 (Reference 24). A reduction factor (defined as the product of the capacity reduction factor and the plastic reduction

factor) was established as 0.385 based on the lower bound curve of test results of 20 ellipsoidal and 28 torispherical test specimens, which also include the two large fabricated heads previously discussed. This resulted in a predicted buckling capacity of 206 psig.

The preceding paragraphs addressed incipient buckling. It is concluded that buckling would not occur prior to reaching the pressure of 174 psig predicted in the BOSOR-5 analyses. Tests indicate that pressure can be significantly increased prior to rupture after the formation of the initial buckles. Failure would occur when local strains reach ultimate either close to a local buckle in the knuckle or at the center of the crown. The best estimate capacity of the head is taken as the theoretical plastic buckling pressure of 174 psig predicted in the BOSOR-5 analyses.

The deterministic severe accident pressure capacity is taken as 60 percent of critical buckling. This is consistent with the safety factor for Service Level C in ASME Code, Case N-284 and results in a containment head capacity of 104 psig.

3.8.2.4.2.3 Equipment Hatches

SECY 93-087 permits evaluation of certain severe accident scenarios against ASME Service Level C limits. The equipment hatch covers were evaluated for buckling against ASME paragraph NE-3222 and according to ASME Code, Case N-284. Use of ASME Code, Case N-284 for this application was confirmed to be appropriate by ASME. The containment internal pressure acts on the convex face of the dished head and the hatch covers are in compression under containment internal pressure loads. The critical buckling capacity is based on classical buckling capacities reduced by capacity reduction factors to account for the effects of imperfections and plasticity. These capacity reduction factors are based on test data and are generally lower-bound values for the tolerances specified in the ASME Code.

The critical buckling pressure is 211 psig for the 16-foot-diameter hatch at an ambient temperature of 100°F. For the Service Level C limits in accordance with paragraph NE 3222, a safety factor of 2.50 is specified, resulting in capabilities of 84 psig (16-foot-diameter). For the Service Level C limits in accordance with Code Case N284, a safety factor of 1.67 is specified, resulting in capabilities of 126 psig (16-foot-diameter).

Typical gaskets have been tested for severe accident conditions as described in NUREG/CR-5096 (Reference 25). The gaskets for the AP1000 will be similar to those tested with material such as Presray EPDM E 603. For such gaskets the onset of leakage occurred at a temperature of about 600°F.

3.8.2.4.2.4 Personnel Airlocks

The capacity of the personnel airlocks was determined by comparing the airlock design to that tested and reported in NUREG/CR-5118 (Reference 3). Critical parameters are the same, so the results of the test apply directly. In the tests the inner door and end bulkhead of the airlock withstood a maximum pressure of 300 psig at 400°F. The capacity of the airlock is therefore at least 300 psig at ambient temperature. The maximum pressure corresponding to Service Level C is conservatively estimated by reducing this capacity in the ratio of the minimum specified material yield to ultimate.

3.8.2.4.2.5 Mechanical and Electrical Penetrations

Subsections 3.8.2.1.3 through 3.8.2.1.6 describe the containment penetrations. Penetration reinforcement is designed following the area replacement method of the ASME Code. The insert plates and sleeves permit development of the hoop tensile yield stresses predicted as the limiting capacity in subsection 3.8.2.4.1. Capacities of the equipment hatch covers are discussed in subsection 3.8.2.4.2.3 and of the personnel airlocks in subsection 3.8.2.4.2.4.

Mechanical penetrations welded directly to the containment vessel are generally piping systems with design pressures greater than that of the containment vessel. Thicknesses of the flued head or end plate are established based on piping support loads or stiffness requirements. The capacities of these penetrations are greater than the capacity of the containment vessel cylinder.

Mechanical penetrations for the large-diameter high-energy lines, such as the main steam and feedwater piping, include expansion bellows. The piping and flued head have large pressure capability. The response of expansion bellows to severe pressure and deformations is described in NUREG/CR-5561 (Reference 4). The bellows can withstand large pressure loading but may tear once the containment vessel deflection becomes large. Testing reported in NUREG/CR-6154 (Reference 26) has shown that the bellows remain leaktight even when subjected to large deflections sufficient to fully compress the bellows. Such large deflections do not occur as long as the containment vessel remains elastic. As described in subsection 3.8.2.4.2.6, the radial deflection of the shell increases substantially once the containment cylinder yields. The resulting deflections are assumed to cause loss of containment function. The containment penetration bellows are designed for a pressure of 90 psig at design temperature within Service Level C limits, concurrent with the relative displacements imposed on the bellows when the containment vessel is pressurized to these magnitudes.

Electrical penetrations have a pressure boundary consisting of the sleeve and an end plate containing a series of modules. The pressure capacity of these elements is large and is greater than the capacity of the containment vessel cylinder at temperatures up to the containment design temperature. Electrical penetration assemblies are also designed to satisfy ASME Service Level C stress limits under a pressure of 90 psig at design temperature. Tests at pressures and temperatures representative of severe accident conditions are described in NUREG/CR-5334 (Reference 5), where the Westinghouse penetrations were irradiated, aged, then tested to 75 psia at 400°F. Other electrical penetration assemblies were tested to higher pressures and temperatures. These tests showed that the electrical penetration assemblies withstand severe accident conditions. The electrical penetration assemblies are qualified for the containment design basis event conditions as described in Appendix 3D. The assemblies are similar to one of those tested by Sandia as reported in NUREG/CR-5334 (Reference 5). The ultimate pressure capacity of the electrical penetration assemblies is primarily determined by the temperature. The maximum temperature of the containment vessel below the operating deck during a severe accident is below the temperature at which the assemblies from the three suppliers in the Sandia tests were tested.

3.8.2.4.2.6 Material Properties

The containment vessel is designed using SA738, Grade B material. This has a specified minimum yield of 60 ksi and ultimate of 85 ksi. Test data for materials having similar chemical

properties were reviewed. In a sample of 122 tests for thicknesses equaling or exceeding 1.50 inches and less than 1.75 inches, the actual yield had a mean value of 69.1 ksi with a standard deviation of 3.3 ksi. Thus, the actual yield is expected to be about 15 percent higher than the minimum yield. Membrane yield of the cylinder is predicted to occur at an internal pressure of 178 psig.

A stress-strain curve for material with chemistry similar to SA738, Grade B, indicated constant yield stress of 81.3 ksi from a strain of 0.002 to 0.006 followed by strain-hardening up to a maximum stress of 94.5 ksi at a strain of 0.079. The first portion of the strain-hardening is nearly linear, with a stress of 90 ksi at a strain of 4 percent. This strain occurs at a stress 10 percent above yield. Thus, a pressure load 10 percent higher than that corresponding to yield of the shell would result in 4 percent strain and a 31-inch radial deflection of the containment cylinder. Such a deflection is expected to cause major distress for penetrations, the air flow path, and local areas where other structures are close to the containment vessel. Loss of function is therefore assumed for the containment once gross yield of the containment cylinder occurs.

3.8.2.4.2.7 Effect of Temperature

The evaluations described in the preceding subsections are based on an ambient temperature of 100°F. Nonmetallic items, such as gaskets, are qualified to function at the design temperature. The capacity of steel elements is reduced in proportion to the reduction due to temperature in yield stress, ultimate stress, or elastic modulus. The cylinder is governed by yield stress, and elastic buckling of the hatch covers is governed by the elastic modulus. The reduction in capacity is estimated using the tables given for material properties in the ASME Code. At 400°F, the yield stress is reduced by 17 percent and the pressure capacity corresponding to gross yield is reduced from 155 to 129 psig.

3.8.2.4.2.8 Summary of Containment Pressure Capacity

The ultimate pressure capacity for containment function is expected to be associated with leakage caused by excessive radial deflection of the containment cylindrical shell. This radial deflection causes distress to the mechanical penetrations, and leakage would be expected at the expansion bellows for the main steam and feedwater piping. There is high confidence that this failure would not occur before stresses in the shell reach the minimum specified material yield. This is calculated to occur at a pressure of 155 psig at ambient temperature and 129 psig at 400°F. Failure would be more likely to occur at a pressure about 15 percent higher based on expected actual material properties.

The deterministic severe accident pressure that can be accommodated according to the ASME Service Level C stress intensity limits and using a factor of safety of 1.67 for buckling of the top head is determined by the capacity of the 16-foot-diameter equipment hatch cover and the ellipsoidal head. The maximum capacity of the hatch cover, calculated according to ASME paragraph NE-3222, Service Level C, is 84 psig at an ambient temperature of 100°F and 81 psig at 300°F. When calculated in accordance with ASME Code, Case N-284, Service Level C, the maximum capacity is 126 psig at an ambient temperature of 100°F and 121 psig at 300°F. The maximum capacity of the ellipsoidal head is 104 psig at 100°F and 91 psig at 300°F.

The maximum pressure that can be accommodated according to the ASME Service Level C stress intensity limits, excluding evaluation of instability, is determined by yield of the cylinder and is 135 psig at an ambient temperature of 100°F and 117 psig at 300°F. This limit is used in the evaluations required by 10 CFR 50.34(f).

3.8.2.5 Structural Criteria

The containment vessel is designed, fabricated, installed, and tested according to the ASME Code, Section III, Subsection NE, and will receive a code stamp.

Stress intensity limits are according to ASME Code, Section III, Paragraph NE-3221 and Table NE-3221-1. [*Critical buckling stresses are checked according to the provisions of ASME Code, Section III, Paragraph NE-3222, or ASME Code Case N-284.*]*

3.8.2.6 Materials, Quality Control, and Special Construction Techniques

Materials for the containment vessel, including the equipment hatches, personnel locks, penetrations, attachments, and appurtenances meet the requirements of NE-2000 of the ASME Code. The basic containment material is SA738, Grade B, plate. The procurement specification for the SA738, grade B, plate includes supplemental requirements S17, Vacuum Carbon-Deoxidized Steel and S20, Maximum Carbon Equivalent for Weldability. This material has been selected to satisfy the lowest service metal temperature requirement of -15°F. This temperature is established by analysis for the portion of the vessel exposed to the environment when the minimum ambient air temperature is -40°F. Impact test requirements are as specified in NE-2000.

The containment vessel is coated with an inorganic zinc coating, except for those portions fully embedded in concrete. The inside of the vessel below the operating floor and up to 8 feet above the operating floor also has a phenolic top coat. Below elevation 100′ the vessel is fully embedded in concrete with the exception of the few penetrations at low elevations (see Figure 3.8.2-4, sheet 3 of 6, for typical details). Embedding the steel vessel in concrete protects the steel from corrosion.

The AP1000 configuration is shown in the general arrangement figures in Section 1.2 and in Figure 3.8.2-1. The exterior of the vessel is embedded at elevation 100′ and concrete is placed against the inside of the vessel up to the maintenance floor at elevation 107′-2″. Above this elevation the inside and outside of the containment vessel are accessible for inspection of the coating. The vessel is coated with an inorganic zinc primer to a level just below the concrete. Seals are provided at the surface of the concrete inside and outside the vessel so that moisture is not trapped next to the steel vessel just below the top of the concrete. The seal on the inside accommodates radial growth of the vessel due to pressurization and heatup.

The plate thickness for the first course (elevation 104′-1.5″ to 116′-10″) of the cylinder is 1.875 inches, which is 1/8-inch thicker than the rest of the vessel. This provides margin in the event there would be any corrosion in the transition region despite the coatings and seals described previously. Equivalent margin is available for the 1.625-inch-thick bottom head in the transition region (elevation 100′ to 104′-1.5″). The plate thickness for the head is a constant thickness and is

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

established by the stresses in the knuckle. As a result, the pressure stresses in the transition zone are well below the allowable stress, providing margin in the event of corrosion in this region.

The quality control program involving welding procedures, erection tolerances, and nondestructive examination of shop- and field-fabricated welds conforms with Subsections NE-4000 and NE-5000 of the ASME Code. The containment vessel is designed to permit its construction using large subassemblies. These subassemblies consist of the two heads and three ring sections. Each ring section comprises three or four courses of plates and is approximately 38 to 51 feet high. These are assembled in an area near the final location, using plates fabricated in a shop facility.

3.8.2.7 Testing and In-Service Inspection Requirements

Testing of the containment vessel and the pipe assemblies forming the pressure boundary within the containment vessel will be according to the provisions of NE-6000 and NC-6000, respectively.

Subsection 6.2.5 describes leak-rate testing of the containment system including the containment vessel.

In-service inspection of the containment vessel will be performed according to the ASME Code Section XI, Subsection IWE, and is the responsibility of the Combined License applicant.

3.8.3 Concrete and Steel Internal Structures of Steel Containment

3.8.3.1 Description of the Containment Internal Structures

The containment internal structures are those concrete and steel structures inside (not part of) the containment pressure boundary that support the reactor coolant system components and related piping systems and equipment. The concrete and steel structures also provide radiation shielding. The containment internal structures are shown on the general arrangement drawings in Section 1.2. The containment internal structures consist of the primary shield wall, reactor cavity, secondary shield walls, in-containment refueling water storage tank (IRWST), refueling cavity walls, operating floor, intermediate floors, and various platforms. The polar crane girders are considered part of the containment vessel. They are described in subsection 3.8.2.

Component supports are those steel members designed to transmit loads from the reactor coolant system to the load-carrying building structures. The component configuration is described in this subsection including the local building structure backing up the component support. The design and construction of the component supports are described in subsection 5.4.10.

The containment internal structures are designed using reinforced concrete and structural steel. At the lower elevations conventional concrete and reinforcing steel are used, except that permanent steel forms are used in some areas in lieu of removable forms based on constructibility considerations. These steel form modules (liners) consist of plate reinforced with angle stiffeners and tee sections, as shown in Figure 3.8.3-16. The angles and the tee sections are on the concrete side of the plate. Welded studs, or similar embedded steel elements, are attached on the concrete face of the permanent steel form where surface attachments transfer loads into the concrete. Where

these surface attachments are seismic Category I, the portion of the steel form module transferring the load into the concrete is classified as seismic Category I.

Walls and floors are concrete filled steel plate structural modules. The walls are supported on the mass concrete containment internal structures basemat with the steel surface plate extending down to the concrete floor on each side of the wall. The steel surface plates of the structural modules provide reinforcement in the concrete. The structural modules are anchored to the base concrete by mechanical connections welded to the steel plate or by lap splices where the reinforcement overlaps shear studs on the steel plate as shown in Figure 3.8.3-8. Figure 3.8.3-1 shows the location of the structural modules. Figures 3.8.3-2 and 3.8.3-15 show the typical structural configuration of the wall modules. A typical floor module is shown in Figure 3.8.3-3 and also in Figure 3.8.3-16 combined with the liner module. These structural modules are structural elements built up with welded steel structural shapes and plates. Concrete is used where required for shielding, but reinforcing steel is not normally used.

Walls and floors exposed to water during normal operation or refueling are constructed using stainless steel plates.

3.8.3.1.1 Reactor Coolant Loop Supports

3.8.3.1.1.1 Reactor Vessel Support System

The reactor vessel is supported by four supports located under the cold legs, which are spaced 90 degrees apart in the primary shield wall. The supports are designed to provide for radial thermal growth of the reactor coolant system, including the reactor vessel, but they prevent the vessel from lateral and torsional movement. The loads are carried by the reactor vessel supports to embedded steel plates of the CA-04 structural module which forms the inside face of the primary shield concrete. Figure 3.8.3-4 shows the reactor vessel supports. Sheet 4 of Figure 3.8.3-14 shows the CA-04 structural module.

3.8.3.1.1.2 Steam Generator Support System

The steam generator vertical support consists of a single vertical column extending from the steam generator compartment floor to the bottom of the steam generator channel head. The column is constructed of heavy plate sections and is pinned at both ends to permit unrestricted radial displacement of the steam generator during plant heatup and cooldown. The location of this column is such that it will allow full access to the steam generator for routine maintenance activities. It is located a sufficient distance away from the reactor coolant pump motors to permit pump maintenance and in-service inspection.

The lower steam generator horizontal support is located at the top of the vertical column. It consists of a tension/compression strut oriented approximately perpendicular to the hot leg. The strut is pinned at both the wall bracket and the vertical column to permit movement of the generator during plant heatup and cooldown.

The upper steam generator horizontal support in the direction of the hot leg is located on the upper shell just above the transition cone. It consists of two large hydraulic snubbers oriented parallel with the hot leg centerline. One snubber is mounted on each side of the generator on top of the

steam generator compartment wall. The hydraulic snubbers are valved to permit steam generator movement for thermal transition conditions, and to "lock-up" and act as rigid struts under dynamic loads.

The upper steam generator horizontal support in the direction normal to the hot leg is located on the lower shell just below the transition cone. It consists of two rigid tension/compression struts oriented perpendicular to the hot leg. The two rigid struts are mounted on the steam generator compartment wall at the elevation of the operating deck. The steam generator loads are transferred to the struts and snubbers through trunnions on the generator shell. Figure 3.8.3-5 shows the steam generator supports.

The steam generator supports are anchored using anchor bolts or steel weldments embedded in the concrete, designed in accordance with Appendix B of ACI 349. The lower portion of the column pedestal, embedded in the concrete, as shown on sheet 1 of Figure 3.8.3-5, transfers the vertical load into the reinforced concrete basemat. The lower and intermediate horizontal supports are located so that the loads are transferred into the plane of the adjacent floor. The upper supports are located so that the loads are transferred into the plane of the steam generator compartment walls.

3.8.3.1.1.3 Reactor Coolant Pump Support System

Because the reactor coolant pumps are integrated into the steam generator channel head, they do not have individual supports. They are supported by the steam generators.

3.8.3.1.1.4 Pressurizer Support System

The pressurizer is supported by four columns mounted from the pressurizer compartment floor. A lateral support is provided at the top of the columns. This lateral support consists of eight struts connecting it to the pressurizer compartment walls. A lateral support is also provided on the upper portion of the pressurizer. This lateral support consists of a ring girder around the pressurizer and eight struts connecting it to the pressurizer compartment walls. Figure 3.8.3-6 shows the pressurizer supports.

3.8.3.1.2 Containment Internal Structures Basemat

The containment internal structures basemat is the reinforced concrete structure filling the bottom head of the containment vessel. It extends from the bottom of the containment vessel head at elevation 66′-6″ up to the bottom of the structural modules that start between elevations 71′-6″ and 103′-0″. The basemat includes rooms as shown on Figure 1.2-5. The primary shield wall and reactor cavity extend from elevation 71′-6″ to elevation 107′-2″. They provide support for the reactor vessel and portions of the secondary shield walls and refueling cavity walls. The general arrangement drawings in Section 1.2 show the location and configuration of the primary shield wall and reactor cavity. The walls of the primary shield, the steam generator compartment and the CVS room are structural modules as shown in Figure 3.8.3-1. The rest of the basemat is reinforced concrete.

3.8.3.1.3 Structural Wall Modules

Structural wall modules are used for the primary shield wall around the reactor vessel, the wall between the vertical access and the CVS room, secondary shield walls around the steam generators and pressurizer, for the east side of the in-containment refueling water storage tank, and for the refueling cavity. The general arrangement drawings in Section 1.2 show the location and configuration. Locations of the structural modules are shown in Figure 3.8.3-1. Isometric views of the structural modules are shown in Figure 3.8.3-14. The secondary shield walls are a series of walls that, together with the refueling cavity wall, enclose the steam generators. Each of the two secondary shield wall compartments provides support and houses a steam generator and reactor coolant loop piping. The in-containment refueling water storage tank is approximately 30 feet high. The floor elevation of this tank is 103′-0″. The tank extends up to about elevation 133′-3″, directly below the operating deck. On the west side, along the containment vessel wall, the tank wall consists of a stainless steel plate stiffened with structural steel sections in the vertical direction and angles in the horizontal direction. Structural steel modules, filled with concrete and forming, in part, the refueling cavity, steam generator compartment, and pressurizer compartment walls, compose the east wall. The refueling cavity has two floor elevations. The area around the reactor vessel flange is at elevation 107′-2″. The lower level is at elevation 98′-1″. The upper and lower reactor internals storage is at the lower elevation, as is the fuel transfer tube. The center line of the fuel transfer tube is at elevation 100′-8.75″.

Structural wall modules consist of steel faceplates connected by steel trusses. The primary purpose of the trusses is to stiffen and hold together the faceplates during handling, erection, and concrete placement. The nominal thickness of the steel faceplates is 0.5 inch. The nominal spacing of the trusses is 30 inches. Shear studs are welded to the inside faces of the steel faceplates. Face plates are welded to adjacent plates with full penetration welds so that the weld is at least as strong as the plate. Plates on each face of the wall module extend down to the elevation of the adjacent floor. Since the floors in the rooms each side of the wall module are at different elevations, one of the plates extends further than the other. This portion is designated on Figure 3.8.3-1 as “CA Structure Module with Single Surface Plate.” A typical configuration is shown in Figure 3.8.3-8. The module functions as a wall above the upper floor level (elevation 103′-0″ in Figure 3.8.3-8). The single plate below this elevation is designed to transfer the reactions at the base of the wall into the base mat. This plate also acts as face reinforcement for the basemat. Basemat reinforcement dowels are provided at the bottom of the single plate as shown in Figure 3.8.3-8. The structural wall modules are anchored to the concrete base by reinforcing steel dowels or other types of connections embedded in the reinforced concrete below. After erection, concrete is placed between the faceplates. Typical details of the structural modules are shown in Figures 3.8.3-2, 3.8.3-8 and 3.8.3-17.

3.8.3.1.4 Structural Floor Modules

Structural floor modules are used for the operating floor at elevation 135′-3″ over the in-containment refueling water storage tank and for the 107′-2″ floor over the rooms in the containment internal structures basemat. The floors are shown on the general arrangement drawings in Section 1.2. The 107′-2″ floors and the floor above the in-containment refueling water storage tank consist of steel tee and wide flange sections, welded to horizontal steel bottom plates

stiffened by transverse stiffeners. After erection, concrete is placed on top of the horizontal plate and around the structural steel section. The remaining region of the operating floor consists of a concrete slab, placed on Q decking supported by structural steel beams. The operating floor is supported by the in-containment refueling water storage tank walls, refueling cavity walls, the secondary shield walls, and steel columns originating at elevation 107′-2″. Structural details of the operating floor structural module are shown in Figure 3.8.3-3.

3.8.3.1.5 Internal Steel Framing

The region of the operating floor away from the in-containment refueling water storage tank consists of a concrete slab, placed on Q decking supported by structural steel beams. The floor at elevation 118′-6″ consists of steel grating supported by structural steel framing. In addition, a number of steel platforms are located above and below the operating floor. These platforms support either grating floors or equipment, such as piping and valves.

3.8.3.2 Applicable Codes, Standards, and Specifications

The following documents are applicable to the design, materials, fabrication, construction, inspection, or testing of the containment internal structures:

[• *American Concrete Institute (ACI), Code Requirements for Nuclear Safety Related Structures, ACI-349-01*]* (refer to subsection 3.8.4.5 for supplemental requirements)

- American Concrete Institute (ACI), ACI Detailing Manual, 1994
- American Concrete Institute (ACI), Standard Specifications for Tolerances for Concrete Construction and Materials, ACI-117-90
- American Concrete Institute (ACI), Guide to Formwork for Concrete, ACI-347-94

[• *American Institute of Steel Construction (AISC), Specification for the Design, Fabrication and Erection of Steel Safety Related Structures for Nuclear Facilities, AISC-N690-1994*]* (refer to subsection 3.8.4.5 for supplemental requirements)

- American Welding Society (AWS), Structural Welding Code, AWS D 1.1-2000
- American Welding Society (AWS), Reinforcing Steel Welding Code, AWS D 1.4-98
- National Construction Issues Group (NCIG), Visual Weld Acceptance Criteria for Structural Welding at Nuclear Power Plants, NCIG-01, Revision 2, May 7, 1985

Nationally recognized industry standards, such as American Society for Testing and Materials, American Concrete Institute, and American Iron and Steel Institute, are used to specify material properties, testing procedures, fabrication, and construction methods. Section 1.9 describes conformance with the Regulatory Guides.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Welding and inspection activities for seismic Category I structural steel, including building structures, structural modules, cable tray supports, and heating, ventilating and air-conditioning (HVAC) duct supports are accomplished in accordance with written procedures and meet the requirements of the American Institute of Steel Construction (AISC N-690). The weld acceptance criteria is as defined in NCIG-01, Revision 2. The welded seams of the plates forming part of the leaktight boundary of the in-containment refueling water storage tank are examined by liquid penetrant and vacuum box after fabrication to confirm that the boundary does not leak.

3.8.3.3 Loads and Load Combinations

The loads and load combinations for the containment internal structures are the same as for other Category I structures described in subsection 3.8.4.3 and the associated tables, except for the following modifications:

> Wind loads (W), tornado loads (W_t), and precipitation loads (N) are not applicable to the design of the containment internal structures because of the protection provided by the steel containment. Therefore, these loading terms have been excluded in the load combinations for the containment internal structures.

3.8.3.3.1 Passive Core Cooling System Loads

Structures are evaluated for pressure and thermal transients associated with operation of the passive core cooling system. The effects of temperatures higher than 100°F on the modulus of elasticity and yield strength of steel are considered.

The passive core cooling system and the automatic depressurization system (ADS) are described in Section 6.3. The automatic depressurization system is in part composed of two spargers that are submerged in the in-containment refueling water storage tank. The spargers provide a controlled distribution of steam flow to prevent imposing excessive dynamic loads on the tank structures. Capped vent pipes are installed in the roof of the tank on the side near the containment wall. These caps prevent debris from entering the tank from the containment operating deck, but they open under slight pressurization of the in-containment refueling water storage tank. This provides a path to vent steam released by the spargers. An overflow is provided from the in-containment refueling water storage tank to the refueling cavity to accommodate volume and mass increases during automatic depressurization system operation. Two sets of loads representing bounding operational or inadvertent transients are considered in the design of the in-containment refueling water storage tank.

- ADS_1 – This automatic depressurization system load is associated with blowdown of the primary system through the spargers when the water in the in-containment refueling water storage tank is cold and the tank is at ambient pressure. Dynamic loads on the in-containment refueling water storage tank due to automatic depressurization system operation are determined using the results from the automatic depressurization system hydraulic test as described in subsection 3.8.3.4.2. The hydrodynamic analyses described in subsection 3.8.3.4.2 show that member forces in the walls of the in-containment refueling water storage tank are bounded by a case with a uniform pressure of 5 psi applied to the walls. The in-containment refueling water storage tank is designed for a uniform pressure of

5 psi applied to the walls. This pressure is taken as both positive and negative due to the oscillatory nature of the hydrodynamic loads. This automatic depressurization system transient is of short duration such that the concrete walls do not heat up significantly. It is combined with ambient thermal conditions. Long-term heating of the tank is bounded by the design for the ADS_2 load.

- ADS_2 – This automatic depressurization system transient considers heatup of the water in the in-containment refueling water storage tank. This may be due to prolonged operation of the passive residual heat removal heat exchanger or due to an automatic depressurization system discharge. For structural design, an extreme transient is defined starting at 50°F since this maximizes the temperature gradient across the concrete-filled structural module walls. Prolonged operation of the passive residual heat removal heat exchanger raises the water temperature from an ambient temperature of 50°F to saturation in about 4 hours, increasing to about 260°F within about 10 hours. Steaming to the containment atmosphere initiates once the water reaches its saturation temperature. The temperature transient is shown in Figure 3.8.3-7. Blowdown of the primary system through the spargers may occur during this transient and occurs prior to 24 hours after the initiation of the event. Since the flow through the sparger cannot fully condense in the saturated conditions, the pressure increases in the in-containment refueling water storage tank and steam is vented through the in-containment refueling water storage tank roof. The in-containment refueling water storage tank is designed for an equivalent static internal pressure of 5 psi in addition to the hydrostatic pressure occurring at any time up to 24 hours after the initiation of the event.

The ADS_1 and ADS_2 loads are considered as live loads. The dynamic ADS_1 load is combined with the safe shutdown earthquake by the square root sum of the squares (SRSS). ADS_2 is an equivalent static pressure which is included algebraically with other normal loads and then combined with plus/minus SSE loads.

3.8.3.3.2 Concrete Placement Loads

The steel faceplates of the structural wall modules, designed for the hydrostatic pressure of the concrete, act as concrete forms. The concrete placement loads are 1050 pounds per square foot determined in accordance with ACI-347. The bending stress in the faceplate due to this hydrostatic pressure of the concrete is approximately 13 ksi, based on the assumption of a continuous faceplate, or 20 ksi based on the assumption of simple spans. The minimum yield strength of material for the faceplates is 36 ksi for A36 steel. The stress is well below the allowable, since the plate is designed to limit the out-of-plane deflection. After the concrete has gained strength, these stresses remain in the steel; however, since the average residual stress is zero and since the concrete no longer requires hydrostatic support, the ultimate strength of the composite section is not affected, and the full steel plate is available to carry other loads as described below.

The steel plates and the concrete act as a composite section after the concrete has reached sufficient strength. The composite section resists bending moment by one face resisting tension and the other face resisting compression. The steel plate resists the tension and behaves as reinforcing steel in reinforced concrete. The composite section is underreinforced so that the steel would yield before the concrete reaches its strain limit of 0.003 in/in. As the steel faceplates are

strained beyond yield to allow the composite section to attain its ultimate capacity, the modest residual bending stress from concrete placement is relieved, since the stress across the entire faceplate in tension is at yield. The small residual strain induced by the concrete placement loads is secondary and has negligible effect on the ultimate bending capacity of the composite section. The stresses in the faceplates resulting from concrete placement are therefore not combined with the stresses in the post-construction load combinations.

3.8.3.4 Analysis Procedures

This subsection describes the modelling and overall analyses of the containment internal structures, including the concrete-filled structural modules. Concrete and steel composite structures are used extensively in conventional construction. Applications include concrete slabs on steel beams and concrete-filled steel columns. Testing of concrete-filled structural modules is described in References 27 through 29 for in-plane loading and in References 30 through 33 for out-of-plane loading. The tests indicate that these composite structures behave in a manner similar to reinforced concrete structures. The initial load deflection behavior is well predicted using the gross properties of the steel and concrete. This is similar to the behavior of reinforced concrete elements where the initial stiffness is predicted by the gross properties. As the load is increased on reinforced concrete members, cracking of the concrete occurs and the stiffness decreases. The behavior of concrete and steel composite structures is similar in its trends to reinforced concrete but has a superior performance. The results of the test program by Akiyama et al. (Reference 27) indicate that concrete and steel composites similar to the structural modules have significant advantages over reinforced concrete elements of equivalent thickness and reinforcement ratios:

- Over 50 percent higher ultimate load carrying capacity
- Three times higher ductility
- Less stiffness degradation under peak cyclic loads, 30 percent for concrete and steel composites versus 65 percent for reinforced concrete

Methods of analysis for the structural modules are similar to the methods used for reinforced concrete. Table 3.8.3-2 summarizes the finite element analyses of the containment internal structures and identifies the purpose of each analysis and the stiffness assumptions for the concrete filled steel modules. For static loads the analyses use the monolithic (uncracked) stiffness of each concrete element. For thermal and dynamic loads the analyses consider the extent of concrete cracking as described in later subsections. Stiffnesses are established based on analyses of the behavior and review of the test data related to concrete-filled structural modules. The stiffnesses directly affect the member forces resulting from restraint of thermal growth. The in-plane shear stiffness of the module influences the fundamental horizontal natural frequencies of the containment internal structures in the nuclear island seismic analyses described in subsection 3.7.2. The out-of-plane flexural stiffness of the module influences the local wall frequencies in the seismic and hydrodynamic analyses of the in-containment refueling water storage tank. Member forces are evaluated against the strength of the section calculated as a reinforced concrete section with zero strength assigned to the concrete in tension.

ACI 349, Section 9.5.2.3 specifies an effective moment of inertia for calculating the deflection of reinforced concrete beams. For loads less than the cracking moment, the moment of inertia is the gross (uncracked) inertia of the section. The cracking moment is specified as the moment corresponding to a maximum flexural tensile stress of $7.5\sqrt{f_c'}$. For large loads, the moment of inertia is that of the cracked section transformed to concrete. The effective moment of inertia provides a transition between these two dependent on the ratio of the cracking moment to the maximum moment in the beam at the stage the deflection is to be computed.

Table 3.8.3-1 summarizes in-plane shear and out-of-plane flexural stiffness properties of the 48-inch and 30-inch walls based on a series of different assumptions. The stiffnesses are expressed for unit length and height of each wall. The ratio of the stiffness to the stiffness of the monolithic case is also shown.

- Case 1 assumes monolithic behavior of the steel plate and uncracked concrete. This stiffness is supported by the test data described in References 27 through 33 for loading that does not cause significant cracking. This stiffness is the basis for the stiffness of the concrete-filled steel module walls in the nuclear island seismic analyses and in the uncracked case for the hydrodynamic analyses.

- Case 2 considers the full thickness of the wall as uncracked concrete. This stiffness value is shown for comparison purposes. It is applicable for loads that do not result in significant cracking of the concrete and is the basis for the stiffness of the reinforced concrete walls in the nuclear island seismic analyses. This stiffness was used in the harmonic analyses of the internal structures described in subsection 3.8.3.4.2.2.

- Case 3 assumes that the concrete in tension has no stiffness. For the flexural stiffness this is the conventional stiffness value used in working stress design of reinforced concrete sections. For in-plane shear stiffness, a 45-degree diagonal concrete compression strut is assumed with tensile loads carried only by the steel plate. The in-plane stiffnesses calculated by these assumptions are lower than the stiffnesses measured in the tests described in References 27 through 29 for loading that causes cracking.

3.8.3.4.1 Seismic Analyses

3.8.3.4.1.1 Finite Element Model

The three-dimensional (3D) lumped-mass stick model of the containment internal structure is developed based on the structural properties obtained from a 3D finite element model. The structural modules are simulated within the finite element model using 3D shell elements. Equivalent shell element thickness and modulus of elasticity of the structural modules are computed as shown below. The shell element properties are computed using the combined gross concrete section and the transformed steel faceplates of the structural modules. This representation models the composite behavior of the steel and concrete.

- Axial and Shear Stiffnesses of module:

$$\sum E A = E_c (L t + 2 (n - 1) L t_s)$$

- Bending Stiffness of module:

$$\sum E I = E_c \left[\frac{L}{12} t^3 + 2 \frac{L}{12} (n-1) \ t_s^3 + 2 (n-1) L \ t_s \left(\frac{t}{2} \right)^2 \right]$$

where:

E_c = concrete modulus of elasticity
n = modular ratio of steel to concrete
L = length of wall module
t = thickness of wall module
t_s = thickness of plate on each face of wall module

These equations lead to an equivalent thickness, t_m, and modulus of elasticity of the plate elements, E_m, as shown below:

$$t_m = \left[\frac{1 + 3 \alpha (n-1)}{1 + \alpha (n-1)} \right]^{1/2} t$$

$$E_m = [1 + \alpha (n-1)] \left[\frac{1 + 3 \alpha (n-1)}{1 + \alpha (n-1)} \right]^{-1/2} E_c$$

where $\alpha = 2t_s / t$ and terms of order α^3 are neglected (for a typical 30-inch thick wall with 1/2-inch steel plates, $\alpha = 0.033$).

3.8.3.4.1.2 Stiffness Assumptions for Global Seismic Analyses

The monolithic initial stiffness (Case 1 of Table 3.8.3-1) is used in the seismic analyses of the containment internal structures and the auxiliary building modules. This stiffness is used since the stresses due to mechanical loads including the safe shutdown earthquake are less than the cracking stress. The maximum in-plane concrete shear stresses in the AP600 containment internal structures modules are 97 psi for the 48-inch wall and 137 psi for the 30-inch wall due to the safe shutdown earthquake based on the monolithic section properties. These stresses will increase slightly for the AP1000 due to the increased height of the steam generator and pressurizer compartments and the increased mass of the steam generators and pressurizer. The stresses will still be well below the magnitude causing significant cracking of concrete so the monolithic assumption is also appropriate for the AP1000.

The broadening of the floor response spectra is sufficient to account for lower structural frequencies due to cracking of those portions of the structural modules that are boundaries of the

in-containment refueling water storage tank exposed to abnormal thermal transients. Cracking due to the abnormal thermal event is primarily in the horizontal and vertical directions. Both tests and analyses show that this cracking has only small effect on the in-plane shear stiffness of a panel.

3.8.3.4.1.3 Stiffness Assumptions for Local Seismic Analyses of In-Containment Refueling Water Storage Tank

The seismic analyses of the in-containment refueling water storage tank address the local response of the walls and water and are performed to verify the structural design of the tank. The lowest significant wall frequency is about 30 hertz using monolithic properties and would not be excited by the seismic input. The local analyses are therefore performed using the cracked section stiffness values based on composite behavior with zero stiffness for the concrete in tension (Case 3 of Table 3.8.3.1). The local analyses use the finite element model described in subsection 3.8.3.4.2.2. Response spectrum analyses are performed using the floor response spectra at the base of the tank.

3.8.3.4.1.4 Damping of Structural Modules

Damping of the structural modules is reported in Reference 27 based on the cyclic load tests of a containment internal structure model. The equivalent viscous damping at the design load level was 5 percent for the concrete-filled steel model. This was almost constant up to the load level at which the steel plate started yielding. Dynamic analyses are performed using 7 percent damping for the reinforced concrete and 5 percent for the structural modules as shown in subsection 3.7.1.

3.8.3.4.2 Hydrodynamic Analyses

This subsection describes the hydrodynamic analyses performed for the AP600 which demonstrated that design of the walls of the in-containment refueling water storage tank for 5 psi as described in subsection 3.8.3.3.1 would bound the loads from the time history transient analysis. The analyses were performed using the AP600 test results. The peak values from these tests are also applicable to the AP1000 since they occur at the beginning of the transient, and the automatic depressurization system and the initial conditions are the same for the two plant designs (Reference 52). The structural configuration of the tank is identical. The minor differences in the height of the steam generator and pressurizer compartment walls and in the mass of the steam generators and pressurizer will have only a minor effect on the significant structural frequencies. Since the time histories applied in the AP600 analyses cover a broad range of frequencies the response of the AP1000 tank boundary will be similar to that of the AP600. The 5 psi pressure design basis for the tank boundary is therefore also applicable to the AP1000.

Hydrodynamic analyses were performed for the AP600 for automatic depressurization system discharge into the in-containment refueling water storage tank. This discharge is designated as ADS_1 in the load description of subsection 3.8.3.3.1 and results in higher hydrodynamic loading than the ADS discharge into a hot tank in ADS_2. The first three stages of the automatic depressurization system valves discharge into the tank through spargers under water, producing hydrodynamic loads on the tank walls and equipment. Hydrodynamic loads, measured in hydraulic tests of the automatic depressurization system sparger in a test tank, are evaluated using the source load approach (Reference 34). Analyses of the tests define source pressure loads that are then used in analyses of the in-containment refueling water storage tank to give the dynamic

responses of the containment internal structures. The basic analysis approach consists of the following steps:

1. A pressure source, an impulsive forcing function at the sparger discharge, is selected from the tests using a coupled fluid structure finite element model of the test tank, taking into account fluid compressibility effects. This source development procedure is based on a comparison between analysis and test results, both near the sparger exit and at the boundaries of the test tank.

2. The pressure source is applied at each sparger location in a coupled fluid structure finite element model of the in-containment refueling water storage tank structure and of the contained water. The mesh characteristics of the model at the sparger locations and the applied forcing functions correspond to those of the test tank analysis.

3.8.3.4.2.1 Sparger Source Term Evaluation

A series of tests was conducted with discharge conditions representative of one sparger for the AP600 (References 35 and 36). Pressure traces measured during the test discharges were investigated, at both sparger exit and tank boundaries to (1) bound the expected discharge from the automatic depressurization system; (2) characterize the pressure wave transmission through the pool water; (3) determine the maximum pressure amplitudes and the frequency content; and (4) produce reference data for qualification of the analytical procedure. Pressure time histories and power spectrum densities were examined at reference sensors, both for the total duration of the discharge transient (about 50 seconds) and for critical time intervals.

Fluid-structure interaction analyses were performed with the ANSYS computer code (Reference 37). The mathematical model consists of a 3D sector finite element model, 15 degrees wide, as shown in Figure 3.8.3-9. It uses STIF30 fluid and STIF63 structural ANSYS finite elements, which take into account fluid compressibility and fluid-structure interaction. Rayleigh damping of 4 percent is used for the concrete structure, and fluid damping is neglected. Direct step-by-step time integration is used. The measured discharge pressures for single time intervals are imposed as uniform forcing functions on the idealized spherical surface of the steam/water interface, and pressures transmitted through the water to the tank boundary are calculated and compared with test measurements. The analyses of the test tank showed satisfactory agreement for the pressures at the tank boundary.

The examination of test results related to the structural design of the in-containment refueling water storage tank under automatic depressurization system hydrodynamic excitation and the comparison with the analytical procedure previously described, lead to the following conclusions regarding the sparger source term definition:

- The automatic depressurization system discharge into cold water produces the highest hydrodynamic pressures. The tests at higher water temperatures produce significantly lower pressures.

- Two pressure time histories, characterized by different shapes and frequency content, can be selected as representative of the sparger discharge pressures; they are assumed as acting on a spherical bubble centered on the sparger centerline and enveloping the ends of the sparger arms.

- The application of such time histories as forcing functions to an analytical model, simulating the fluid structure interaction effects in the test tank, has been found to predict the measured tank wall pressures, for the two selected reference time intervals.

- The two defined sparger source term pressure time histories can be used as forcing functions for global hydrodynamic analyses of the in-containment refueling water storage tank by developing a comprehensive fluid-structure finite element model and reproducing the test tank mesh pattern in the sparger region.

- The hydrodynamic loads on the vessel head support columns and ADS sparger piping located in the IRWST are developed from the forcing functions using the methodology documented in Reference 51.

3.8.3.4.2.2 In-Containment Refueling Water Storage Tank Analyses

The in-containment refueling water storage tank is constructed as an integral part of the containment internal structures as described in subsection 3.8.3.1.3. It contains two depressurization spargers that are submerged approximately 9 feet below the normal water level. Transmission of the hydrodynamic pressures from the sparger discharge to the wetted in-containment refueling water storage tank is evaluated using the coupled fluid-structure interaction method similar to that described for the test tank analysis in the previous subsection.

The 3D ANSYS finite element model includes the in-containment refueling water storage tank boundary, the water within the in-containment refueling water storage tank, the adjacent structural walls of the containment internal structures, and the operating floor. The model of the in-containment refueling water storage tank, shown in Figures 3.8.3-10 (sheet 2), 3.8.3-11, and 3.8.3-12, represents the outer steel structures, the inner concrete walls, and the water. The model of the adjacent structural walls and floors is shown in Figure 3.8.3-10 (sheet 1). The flexible steel outer wall is represented using beam and shell elements; isotropic plate elements are used to represent the inner structural module walls. The water is modelled as a compressible fluid to provide an acoustic medium to transmit the source pressure. The model has two bubble boundaries representing the spargers. Pressure loads are applied to the solid element faces adjacent to the air bubbles. The forcing functions at the sparger locations are conservatively assumed to be in phase. Rayleigh damping of 5 percent is used for the concrete-filled structural modules and fluid damping is neglected. All degrees of freedom were retained in the step-by-step direct integration solution procedure for the in-containment refueling water storage tank boundary and the water. Degrees of freedom in the adjacent walls and floor were condensed by Guyon reduction.

Significant structural frequencies of the AP600 containment internal structures were analyzed using the harmonic response option with the ANSYS model of the in-containment refueling water storage tank and containment internal structures. A harmonic unit pressure is applied at the

surface of the spherical bubble representing the automatic depressurization system spargers. Material properties for the concrete elements are based on the uncracked gross concrete section (Case 2 of Table 3.8.3-1). The results of these harmonic response analyses show the response deflection as a function of input frequency at nodes in the containment internal structures. The harmonic response analyses show that the largest responses are close to the wetted boundary of the in-containment refueling water storage tank and that the significant frequencies are from 18 to 50 hertz.

Two time histories are identified for the structural hydrodynamic analyses; one has significant frequencies below 40 hertz while the other has significant frequencies in the range of 40 to 60 hertz. Both time history inputs are used in the hydrodynamic analyses with the monolithic uncracked section properties for all walls. The lower frequency input is also applied in lower bound analyses using the cracked section stiffness values (Case 3 of Table 3.8.3-1) for the concrete walls that are boundaries of the in-containment refueling water storage tank. Monolithic properties are used for the other walls. Results from these cases are enveloped, thereby accounting for variabilities in the structural analyses.

The analyses of the AP600 in-containment refueling water storage tank give wall pressures, displacements, accelerations, hydrodynamic floor response spectra, and member forces due to the automatic depressurization system discharge pressure forcing functions. Consideration of pressure wave transmission and fluid-structure interaction shows a significant wall pressure attenuation with distance from the sparger region and with increasing wall flexibilities, relative to the measured sparger pressure forcing function. The member stresses are evaluated against the allowable stresses specified in subsection 3.8.3.5 for seismic Category I structures, considering the hydrodynamic loads as live loads. The analyses show that the member forces in the walls of the in-containment refueling water storage tank are bounded by a case with a uniform pressure of 5 psi applied to the walls.

3.8.3.4.3 Thermal Analyses

The in-containment refueling water storage tank water and containment atmosphere are subject to temperature transients as described in subsection 3.8.3.3.1. The temperature transients result in a nonlinear temperature distribution within the wall modules. Temperatures within the concrete wall are calculated in a unidimensional heat flow analysis. The average and equivalent linear gradients are applied to a finite element model of the containment internal structures at selected times during the transient. The effect of concrete cracking is considered in the stiffness properties for the concrete elements subjected to the thermal transient. The finite element model is that described in subsection 3.8.3.4.2.2 except that the model of the water in the IRWST is not needed.

The structural modules are subject to a rapid temperature transient in the event of a loss-of-coolant accident (LOCA) or a main steam line break (MSLB). The structural modules were evaluated for these rapid temperature transients. The evaluation considered both carbon and stainless steel faceplates. The steel plate heats up most rapidly in the LOCA event with temperatures up to 270°F in the first few minutes for an ambient initial temperature of 50°F. The faceplate of the structural module will see differential temperatures of 220°F relative to the concrete. The concrete heats up more slowly and does not see a significant temperature increase during the early part of the transient. There is relative thermal growth of the faceplate, causing shear loads in the shear studs,

and embedded angles of the structural steel trusses that are welded to the faceplate. The heatup of the surface plates during the initial portion of the LOCA transient results in cracking of the concrete walls except in regions where there is significant external restraint. The structural module maintains its integrity throughout the rapid thermal transient.

Thermal transients for the design basis accidents are described in Section 6.3. The analyses for these transients are similar to those described above.

3.8.3.5 Design Procedures and Acceptance Criteria

The containment internal structures that contain reinforcing steel including most of the areas below elevation 98′, are designed by the strength method, as specified in the ACI Code Requirements for Nuclear Safety Related Structures, ACI-349. This code includes ductility criteria for use in detailing, placing, anchoring, and splicing of the reinforcing steel.

The internal steel framing is designed according to the AISC Specification for the Design, Fabrication and Erection of Steel Safety Related Structures for Nuclear Facilities, AISC-N690, supplemented by the requirements given in subsection 3.8.4.5.

The secondary shield walls, in-containment refueling water storage tank, refueling cavity, and operating floor above the in-containment refueling water storage tank are designed using structural modules. Concrete-filled structural wall modules are designed as reinforced concrete structures in accordance with the requirements of ACI-349, as supplemented in the following paragraphs. Structural floor modules are designed as composite structures in accordance with AISC-N690.

Methods of analysis used are based on accepted principles of structural mechanics and are consistent with the geometry and boundary conditions of the structures.

The methods described in subsection 3.7.2 are employed to obtain the safe shutdown earthquake loads at various locations in the containment internal structures. The safe shutdown earthquake loads are derived from the equivalent static analysis of a three-dimensional, finite element model representing the entire containment internal structures.

The determination of pressure and temperature loads due to pipe breaks is described in subsections 3.6.1 and 6.2.1.2. Subcompartments inside containment containing high energy piping are designed for a pressurization load of 5 psi. The pipe tunnel in the CVS room (room 11209, Figure 1.2-6) is designed for a pressurization load of 7.5 psi. These subcompartment design pressures bound the pressurization effects due to postulated breaks in high energy pipe. The design for the effects of postulated pipe breaks is performed as described in subsection 3.6.2. Determination of pressure loads resulting from actuation of the automatic depressurization system is described in subsection 3.8.3.3.1.

Determination of reactor coolant loop support loads is described in subsection 3.9.3. Design of the reactor coolant loop supports within the jurisdiction of ASME Code, Section III, Division 1, Subsection NF is described in subsections 3.9.3 and 5.4.10.

Computer codes used are general purpose codes. The code development, verification, validation, configuration control, and error reporting and resolution are according to the Quality Assurance requirements of Chapter 17.

3.8.3.5.1 Reactor Coolant Loop Supports

3.8.3.5.1.1 Reactor Vessel Support System

The embedded portions of the reactor vessel supports, which are outside the ASME jurisdictional boundary, are designed by elastic methods of analysis. They are analyzed and designed to resist the applicable loads and load combinations given in subsection 3.8.4.3. The design is according to AISC-N690 and ACI-349. Figure 3.8.3-4 shows the jurisdictional boundaries.

3.8.3.5.1.2 Steam Generator Support System

The embedded portions of the steam generator supports, which are outside the ASME jurisdictional boundary, are designed by elastic methods of analysis. They are analyzed and designed to resist the applicable loads and load combinations given in subsection 3.8.4.3. The design is according to AISC-N690 and ACI-349. Figure 3.8.3-5 shows the jurisdictional boundaries.

3.8.3.5.1.3 Reactor Coolant Pump Support System

The reactor coolant pumps are integrated into the steam generator channel head and consequently do not have a separate support system.

3.8.3.5.1.4 Pressurizer Support System

The embedded portions of the pressurizer supports, which are outside the ASME jurisdictional boundary, are designed by elastic methods of analysis. They are analyzed and designed to resist the applicable loads and load combinations given in subsection 3.8.4.3. The design is according to AISC-N690 and ACI-349. Figure 3.8.3-6 shows the jurisdictional boundaries.

3.8.3.5.2 Containment Internal Structures Basemat

The containment internal structures basemat including the primary shield wall and reactor cavity are designed for dead, live, thermal, pressure, and safe shutdown earthquake loads. The structural modules are designed as described in subsection 3.8.3.5.3.

The reinforced concrete forming the base of the containment internal structures is designed according to ACI 349.

3.8.3.5.3 Structural Wall Modules

Structural wall modules without concrete fill, such as the west wall of the in-containment refueling water storage tank, are designed as steel structures, according to the requirements of AISC-N690. This code is applicable since the module is constructed entirely out of structural steel plates and shapes. In local areas stresses due to restraint of thermal growth may exceed yield and

the allowable stress intensity is 3 S_{m1}. This allowable is based on the allowable stress intensity for Service Level A loads given in ASME Code, Section III, Subsection NE, Paragraph NE-3221.4.

The concrete-filled steel module walls are designed for dead, live, thermal, pressure, safe shutdown earthquake, and loads due to postulated pipe breaks. The in-containment refueling water storage tank walls are also designed for the hydrostatic head due to the water in the tank and the hydrodynamic pressure effects of the water due to the safe shutdown earthquake, and automatic depressurization system pressure loads due to sparger operation. The walls of the refueling cavity are also designed for the hydrostatic head due to the water in the refueling cavity and the hydrodynamic pressure effects of the water due to the safe shutdown earthquake.

Figure 3.8.3-8 shows the typical design details of the structural modules, typical configuration of the wall modules, typical anchorages of the wall modules to the reinforced base concrete, and connections between adjacent modules. Concrete-filled structural wall modules are designed as reinforced concrete structures in accordance with the requirements of ACI-349, as supplemented in the following paragraphs. The faceplates are considered as the reinforcing steel, bonded to the concrete by headed studs. The application of ACI-349 and the supplemental requirements are supported by the behavior studies described in subsection 3.8.3.4.1. The steel plate modules are anchored to the reinforced concrete basemat by mechanical connections welded to the steel plate or by lap splices where the reinforcement overlaps shear studs on the steel plate. The design of critical sections is described in subsection 3.8.3.5.8.

3.8.3.5.3.1 Design for Axial Loads and Bending

Design for axial load (tension and compression), in-plane bending, and out-of-plane bending is in accordance with the requirements of ACI-349, Chapters 10 and 14.

3.8.3.5.3.2 Design for In-Plane Shear

Design for in-plane shear is in accordance with the requirements of ACI-349, Chapters 11 and 14. The steel faceplates are treated as reinforcing steel, contributing as provided in Section 11.10 of ACI-349.

3.8.3.5.3.3 Design for Out-of-Plane Shear

Design for out-of-plane shear is in accordance with the requirements of ACI-349, Chapter 11.

3.8.3.5.3.4 Evaluation for Thermal Loads

The effect of thermal loads on the structural wall modules, with and without concrete fill, is evaluated by using the working stress design method for load combination 3 of Tables 3.8.4-1 and 3.8.4-2. This evaluation is in addition to the evaluation using the working stress design method of AISC N690 or the strength design method of ACI-349 for the load combinations without the thermal load. Acceptance for the load combination with normal thermal loads, which includes the thermal transients described in subsection 3.8.3.3.1, is that the stress in general areas of the steel plate be less than yield. In local areas where the stress may exceed yield the total stress intensity range is less than twice yield. This evaluation of thermal loads is based on the ASME Code

philosophy for Service Level A loads given in ASME Code, Section III, Subsection NE, Paragraphs NE-3213.13 and 3221.4.

3.8.3.5.3.5 Design of Trusses

The trusses provide a structural framework for the modules, maintain the separation between the faceplates, support the modules during transportation and erection, and act as "form ties" between the faceplates when concrete is being placed. After the concrete has cured, the trusses are not required to contribute to the strength or stiffness of the completed modules. However, they do provide additional shear capacity between the steel plates and concrete as well as additional strength similar to that provided by stirrups in reinforced concrete. The trusses are designed according to the requirements of AISC-N690.

3.8.3.5.3.6 Design of Shear Studs

The wall structural modules are designed as reinforced concrete elements, with the faceplates serving as reinforcing steel. Since the faceplates do not have deformation patterns typical of reinforcing steel, shear studs are provided to transfer the forces between the concrete and the steel faceplates. The shear studs make the concrete and steel faceplates behave compositely. In addition, the shear studs permit anchorage for piping and other items attached to the walls.

The size and spacing of the shear studs is based on Section Q1.11.4 of AISC-N690 to develop full composite action between the concrete and the steel faceplates.

3.8.3.5.4 Structural Floor Modules

Figure 3.8.3-3 shows the typical design details of the floor modules. The operating floor is designed for dead, live, thermal, safe shutdown earthquake, and pressure due to automatic depressurization system operation or due to postulated pipe break loads. The operating floor region above the in-containment refueling water storage tank is a series of structural modules. The remaining floor is designed as a composite structure of concrete slab and steel beams in accordance with AISC-N690.

For vertical downward loads, the floor modules are designed as a composite section, according to the requirements of Section Q1.11 of AISC-N690. Composite action of the steel section and concrete fill is assumed based on meeting the intent of Section Q1.11.1 for beams totally encased in concrete. Although the bottom flange of the steel section is not encased within concrete, the design configuration of the floor module provides complete concrete confinement to prevent spalling. It also provides a better natural bonding than the code-required configuration.

For vertical upward loads, no credit is taken for composite action. The steel members are relied upon to provide load-carrying capacity. Concrete, together with the embedded angle stiffeners, is assumed to provide stability to the plates.

Floor modules are designed using the following basic assumptions and related requirements:

- Concrete provides restraint against buckling of steel plates. The buckling unbraced length of the steel plate, therefore, is assumed to equal the span length between the fully embedded steel plates and shapes.
- Although the floor modules forming the top (ceiling) of the in-containment refueling water storage tank are not in contact with water, stainless steel plates are used for the tank boundary.
- The floor modules are designed as simply supported beams.

3.8.3.5.4.1 Design for Vertical Downward Loads

The floor modules are designed as a one-way composite concrete slab and steel beam system in supporting the vertical downward loads. The effective width of the concrete slab is determined according to Section Q1.11.1 of AISC-N690. The effective concrete compression area is extended to the neutral axis of the composite section. The concrete compression area is treated as an equivalent steel area based on the modular ratio between steel and concrete material. Figure 3.8.3-13 shows the effective composite sections. The steel section is proportioned to support the dead load and construction loads existing prior to hardening of the concrete. The allowable stresses are provided in Table 3.8.4-1.

3.8.3.5.4.2 Design for Vertical Upward Loads

For vertical upward loads, the floor modules are designed as noncomposite steel structures. The effective width, b_e, of the faceplate in compression is based on post-buckling strength of steel plates and is determined from Equation (4.16) of Reference 44. The faceplates of the structural floor modules are stiffened and supported by embedded horizontal angles. Hence, the buckling unbraced length of the faceplates is equal to the span length between the horizontal angles. Since concrete provides restraint against buckling of the steel plates, a value of 0.65 is used for k when calculating the effective length of the steel plates and stiffeners whenever the plate or stiffener is continuous. The buckling stress, f_{cr}, of the faceplates is determined from Sections 9.2 and 9.3 of Reference 45. The effective width of the faceplates of the structural floor modules in compression is shown in Figure 3.8.3-13. The allowable stresses are provided in Table 3.8.4-1.

3.8.3.5.4.3 Design for In-Plane Loads

In-plane shear loads acting on the floor modules are assumed to be resisted only by the steel faceplate without reliance on the concrete for strength. The stresses in the faceplate due to the in-plane loads are combined with those due to vertical loads. The critical stress locations of the floor faceplate are evaluated for the combined normal and shear stress, based on the von Mises yield criterion:

For the particular case of a two-dimension stress condition the equation is:

$$(\sigma_1)^2 - \sigma_1\sigma_2 + (\sigma_2)^2 = (f_y)^2$$

where σ_1 and σ_2 are the principal stresses and f_y is the uniaxial yield stress.

For the faceplate where normal, σ, and shear, τ, stresses are calculated, the principal stresses can be expressed as follows:

$$\sigma_1 = \left(\frac{\sigma}{2}\right) + \sqrt{\frac{\sigma^2}{4} + \tau^2}$$

$$\sigma_2 = \left(\frac{\sigma}{2}\right) - \sqrt{\frac{\sigma^2}{4} + \tau^2}$$

Therefore, the condition at yield becomes:

$$\sigma^2 + 3\tau^2 = (f_y)^2$$

For the design of the structural floor module faceplate, the allowable stresses for the various loading conditions are as follows:

Normal condition:

$$\sigma^2 + 3\tau^2 \leq (0.6\ f_y)^2$$

Severe condition:

$$\sigma^2 + 3\tau^2 \leq (0.6\ f_y)^2$$

Extreme/abnormal condition:

$$\sigma^2 + 3\tau^2 \leq (0.96\ f_y)^2$$

Thermal stresses in the faceplates result from restraint of growth during the thermal transients described in subsection 3.8.3.3.1. Evaluation for thermal stresses is the same as discussed in subsection 3.8.3.5.3.4 for the wall modules.

3.8.3.5.5 Internal Steel Framing

Internal steel framing is analyzed and designed according to AISC-N690. Seismic analysis methods are described in subsection 3.7.3.

3.8.3.5.6 Steel Form Modules

The steel form modules consist of plate reinforced with angle stiffeners and tee sections as shown in Figure 3.8.3-16. The steel form modules are designed for concrete placement loads defined in subsection 3.8.3.3.2.

The steel form modules are designed as steel structures according to the requirements of AISC-N690. This code is applicable since the form modules are constructed entirely out of structural steel plates and shapes and the applied loads are resisted by the steel elements.

3.8.3.5.7 Design Summary Report

A design summary report is prepared for containment internal structures documenting that the structures meet the acceptance criteria specified in subsection 3.8.3.5.

Deviations from the design due to as-procured or as-built conditions are acceptable based on an evaluation consistent with the methods and procedures of Section 3.7 and 3.8 provided the following acceptance criteria are met.

- The structural design meets the acceptance criteria specified in Section 3.8

- The seismic floor response spectra meet the acceptance criteria specified in subsection 3.7.5.4

Depending on the extent of the deviations, the evaluation may range from documentation of an engineering judgement to performance of a revised analysis and design. The results of the evaluation will be documented in an as-built summary report by the Combined License applicant.

3.8.3.5.8 Design Summary of Critical Sections

3.8.3.5.8.1 Structural Wall Modules

[*This subsection summarizes the design of the following critical sections:*

- *South west wall of the refueling cavity (4′ 0″ thick)*
- *South wall of west steam generator cavity (2′ 6″ thick)*
- *North east wall of in-containment refueling water storage tank (2′ 6″ thick)*]*

[*The thicknesses and locations of these walls which are part of the boundary of the in-containment refueling water storage tank are shown in Table 3.8.3-3 and Figure 3.8.3-18. They are the portions of the structural wall modules experiencing the largest demand. The structural configuration and typical details are shown in Figures 3.8.3-1, 3.8.3-2, 3.8.3-8, 3.8.3-14, 3.8.3-15, and 3.8.3-17.*]* The structural analyses are described in subsection 3.8.3.4 summarized in Table 3.8.3-2. The design procedures are described in subsection 3.8.3.5.3.

[*The three walls extend from the floor of the in-containment refueling water storage tank at elevation 103′ 0″ to the operating floor at elevation 135′ 3″. The south west wall is also a boundary of the refueling cavity and has stainless steel plate on both faces. The other walls have stainless steel on one face and carbon steel on the other. For each wall design information is summarized in Tables 3.8.3-4, 3.8.3-5 and 3.8.3-6 at three locations. Results are shown at the middle of the wall (mid span at mid height), at the base of the wall at its mid point (mid span at base) and at the base of the wall at the end experiencing greater demand (corner at base). The first part of each table shows the member forces due to individual loading. The lower part of the*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

table shows governing load combinations. The steel plate thickness required to resist mechanical loads is shown at the bottom of the table as well as the thickness provided. The maximum principal stress for the load combination including thermal is also tabulated. If this value exceeds the yield stress at temperature, a supplemental evaluation is performed]* as described in subsection 3.8.3.5.3.4; [*for these cases the maximum stress intensity range is shown together with the allowable stress intensity range which is twice the yield stress at temperature.*]*

3.8.3.5.8.2 In-Containment Refueling Water Storage Tank Steel Wall

[*The in-containment refueling water storage tank steel wall is the circular boundary of the in-containment refueling water storage tank. The structural configuration and typical details are shown in sheet 3 of Figure 3.8.3-8.*]* The structural analyses are described in subsection 3.8.3.4 and summarized in Table 3.8.3-2. The design procedures are described in subsection 3.8.3.5.3. [*The steel wall extends from the floor of the in-containment refueling water storage tank at elevation 103′0″ to the operating floor at elevation 135′3″. The wall is a 5/8″ thick stainless steel plate. It has internal vertical stainless steel T-section columns spaced 4′-8″ apart and external hoop carbon steel (L-section) angles spaced 18″ to 24″ apart. The wall is fixed to the adjacent modules and floor except for the top of columns which are free to slide radially and to rotate around the hoop direction.*

The wall is evaluated as vertical and horizontal beams. The vertical beams comprise the T-section columns plus the effective width of the plate. The horizontal beams comprise the L-section angles plus the effective width of the plate. Table 3.8.3-7 shows the ratio of the design stresses to the allowable stresses. When thermal effects result in stresses above yield, the evaluation is in accordance with the supplemental criteria]* as described in subsection 3.8.3.5.3.4.

3.8.3.5.8.3 Column Supporting Operating Floor

[*This subsection summarizes the design of the most heavily loaded column in the containment internal structures. The column extends from elevation 107′-2″ to the underside of the operating floor at elevation 135′-3″. In addition to supporting the operating floor, it also supports a steel grating floor at elevation 118′-0″.*

The load combinations in Table 3.8.4-1 were used to assess the adequacy of the column. For mechanical load combinations, the maximum interaction factor due to biaxial bending and axial load is 0.59. For load combinations with thermal loads, the maximum interaction factor is 0.94. Since the interaction factors are less than 1, the column is adequate for all the applied loads.]*

3.8.3.6 Materials, Quality Control, and Special Construction Techniques

Subsection 3.8.4.6 describes the materials and quality control program used in the construction of the containment internal structures. The structural steel modules are constructed using A36 plates and shapes. Nitronic 33 (American Society for Testing and Materials 240, designation S24000, Type XM-29) stainless steel plates are used on the surfaces of the modules in contact with water during normal operation or refueling. The structural wall and floor modules are fabricated and erected in accordance with AISC-N690. Loads during fabrication and erection due to handling

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

and shipping are considered as normal loads as described in subsection 3.8.4.3.1.1. Packaging, shipping, receiving, storage and handling of structural modules are in accordance with NQA-2, Part 2.2 (formerly ANSI/ASME N45.2.2 as specified in AISC N690).

3.8.3.6.1 Fabrication, Erection, and Construction of Structural Modules

Modular construction techniques are used extensively in the containment internal structures (Figure 3.8.3-1). Subassemblies, sized for commercial rail shipment, are assembled offsite and transported to the site. Onsite fabrication consists of combining the subassemblies in structural modules, which are then installed in the plant. A typical modular construction technique is described in the following paragraphs for Module CA01, which is the main structural module in the containment internal structures.

The CA01 module is a multicompartmented structure which, in its final form, comprises the central walls of the containment internal structures. The vertical walls of the module house the refueling cavity, the reactor vessel compartment, and the two steam generator compartments. The module (Figure 3.8.3-14) is in the form of a "T" and is approximately 88 feet long, 95 feet wide and 86 feet high. The module is assembled from about 40 prefabricated wall sections called structural submodules (Figure 3.8.3-15). The submodules are designed for railroad transport from the fabricator's shop to the plant site with sizes up to 12 feet by 12 feet by 80 feet long, weighing up to 80 tons. A typical submodule weighs between 9 and 11 tons. The submodules are assembled outside the nuclear island with full penetration welds between the faceplates of adjacent subunits. The completed CA01 module is lifted to its final location within the containment vessel by the heavy lift construction crane. Following placement of the CA01 module within the containment building, the hollow wall structures are filled with concrete, forming a portion of the structural walls of the containment internal structures.

Tolerances for fabrication, assembly and erection of the structural modules conform to the requirements of section 4 of ACI-117, sections 3.3 and 3.4 of AWS D1.1, and sections Q1.23 and Q1.25 of AISC-N690.

3.8.3.6.2 Nondestructive Examination

Nondestructive examination of the submodules and module is performed according to AISC-N690 and AWS D 1.1. Welds are visually examined for 100 percent of their length. Full penetration welds are inspected by ultrasonic or radiographic examination for 10 percent of their length. Partial penetration welds are inspected by magnetic particle or liquid penetrant examination for 10 percent of their length.

3.8.3.6.3 Concrete Placement

After installation of the CA01 module in the containment, the hollow walls are filled with concrete. Concrete is placed in each wall continuously from bottom to top. The concrete is placed through multiple delivery trunks located along the top of the wall. It is placed in incremental layers with the placement rate based on the pressure of the wet concrete and its setting time. During concrete placement, workers and inspectors have access to the inside of the modules. The arrangement of the module internal trusses provides communication to aid in the free flow of concrete and movement of personnel.

3.8.3.7 In-Service Testing and Inspection Requirements

There are no in-service testing or inspection requirements for the containment internal structures.

3.8.3.8 Construction Inspection

Construction inspection is conducted to verify the concrete wall thickness and the surface plate thickness. Inspections will be measured at applicable sections excluding designed openings or penetrations. Inspections will confirm that each section provides the minimum required steel and concrete thicknesses as shown in Table 3.8.3-3. The minimum required steel and concrete thicknesses represent the minimum values to meet the design basis loads. Table 3.8.3-3 also indicates the steel plate thickness provided which may exceed the minimum required value for the following reasons:

- Structural margin
- Ease of construction
- Construction loads
- Use of standard thicknesses

3.8.4 Other Category I Structures

The other seismic Category I structures are the shield building and the auxiliary building. New fuel and spent fuel racks are described in Section 9.1.

General criteria in this section describing the loads, load combinations, materials, and quality control are also applicable to the containment internal structures described in subsection 3.8.3.

3.8.4.1 Description of the Structures

3.8.4.1.1 Shield Building

The shield building is the shield building structure and annulus area that surrounds the containment building. It shares a common basemat with the containment building and the auxiliary building. The shield building is a reinforced concrete structure. The figures in Section 1.2 show the layout of the shield building and its interface with the other buildings of the nuclear island.

The following are the significant features and the principal systems and components of the shield building:

- Shield building cylindrical structure
- Shield building roof structure
- Lower annulus area
- Middle annulus area
- Upper annulus area
- Passive containment cooling system air inlet
- Passive containment cooling system water storage tank

- Passive containment cooling system air diffuser
- Passive containment cooling system air baffle
- Passive containment cooling system air inlet plenum

The cylindrical section of the shield building provides a radiation shielding function, a missile barrier function, and a passive containment cooling function. Additionally, the cylindrical section structurally supports the roof with the passive containment cooling system water storage tank and serves as a major structural member for the nuclear island. The floor slabs and structural walls of the auxiliary building are structurally connected to the cylindrical section of the shield building.

The shield building roof is a reinforced concrete shell supporting the passive containment cooling system tank and air diffuser. Air intakes are located at the top of the cylindrical portion of the shield building. The conical roof supports the passive containment cooling system tank as shown in Figure 3.8.4-2. The air diffuser is located in the center of the roof and discharges containment cooling air upwards.

The passive containment cooling system tank has a stainless steel liner which provides a leaktight barrier on the inside surfaces of the tank. The wall liner consists of a plate with stiffeners on the concrete side of the plate. The floor liner is welded to steel plates embedded in the surface of the concrete. The liner is welded and inspected during construction to assure its leaktightness. Leak chase channels are provided over the liner welds. This permits monitoring for leakage and also prevents degradation of the reinforced concrete wall due to freezing and thawing of leakage. The exterior face of the reinforced concrete boundary of the PCS tank is designed to control cracking in accordance with paragraph 10.6.4 of ACI 349 with the reinforcement steel stress based on sustained loads including thermal effects.

The upper annulus of the shield building is the volume of the annulus between elevation 132′-3″ and the bottom of the air diffuser. The middle annulus area, the volume of annulus between elevation 100′-0″ and elevation 132′-3″, contains the majority of the containment vessel penetrations. The area below elevation 100′-0″ is the lower annulus of the shield building. There is a concrete floor slab in the annulus at elevation 132′-3″, which is incorporated with the stiffener attached to the containment vessel.

A permanent flexible watertight and airtight seal is provided between the concrete floor slab at elevation 132′-3″ and the shield building to provide an environmental barrier between the upper and middle annulus sections. The flexible watertight seal is utilized to seal against water leakage from the upper annulus into the middle annulus. The seal is designated as nonsafety-related and nonseismic; it is not relied upon to mitigate design basis events. The seal is able to accommodate events resulting in containment temperature and pressure excursions that result in lateral shell movement inward or outward.

3.8.4.1.2 Auxiliary Building

The auxiliary building is a reinforced concrete and structural steel structure. Three floors are above grade and two are located below grade. It is one of the three buildings that make up the nuclear island and shares a common basemat with the containment building and the shield building.

The auxiliary building is a C-shaped section of the nuclear island that wraps around approximately 50 percent of the circumference of the shield building. The floor slabs and the structural walls of the auxiliary building are structurally connected to the cylindrical section of the shield building.

The figures in Section 1.2 show the layout of the auxiliary building and its interface with the other buildings of the nuclear island. The following are the significant features and the principal systems and components of the auxiliary building:

- Main control room
- Remote shutdown room
- Class 1E dc switchgear
- Class 1E batteries
- Reactor trip switchgear
- Reactor coolant pump trip switchgear
- Main steam and feedwater piping
- Main control room heating, ventilating, and air conditioning (HVAC)
- Class 1E switchgear rooms heating, ventilating, and air conditioning
- Spent fuel pool
- Fuel transfer canal
- Cask loading and washdown pits
- New fuel storage area
- Cask handling crane
- Fuel handling machine
- Chemical and volume control system (CVS) makeup pumps
- Normal residual heat removal system (RNS) pumps and heat exchangers
- Liquid radwaste tanks and components
- Spent fuel cooling system
- Gaseous radwaste processing system
- Mechanical and electrical containment penetrations

Structural modules are used for part of the south side of the auxiliary building. These structural modules are structural elements built up with welded steel structural shapes and plates. Concrete is used where required for shielding, but reinforcing steel is not normally used. These modules include the spent fuel pool, fuel transfer canal, and cask loading and cask washdown pits. The configuration and typical details of the structural modules are the same as for the structural modules described in subsection 3.8.3.1 for the containment internal structures. Figure 3.8.4-4 shows the location of the structural modules. The thickness of the structural wall modules ranges from 2′-6″ to 5′-0″. The structural modules extend from elevation 66′-6″ to elevation 135′-3″. The minimum thickness of the faceplates is 0.5 inch.

The ceiling of the main control room (floor at elevation 135′-3″), and the instrumentation and control rooms (floor at elevation 117′-6″) are designed as finned floor modules (Figure 3H.5-9). A finned floor consists of a 24-inch-thick concrete slab poured over a stiffened steel plate ceiling. The fins are rectangular plates welded perpendicular to the plate. Shear studs are welded on the other side of the steel plate, and the steel and concrete act as a composite section. The fins are exposed to the environment of the room, and enhance the heat-absorbing capacity of the ceiling

(see Design Control Document (DCD) subsection 6.4.2.2). Several shop-fabricated steel panels, placed side by side, are used to construct the stiffened plate ceiling in a modularized fashion. The stiffened plate is designed to withstand construction loads prior to concrete hardening.

The new fuel storage area is a separate reinforced concrete pit providing temporary dry storage for the new fuel assemblies.

A cask handling crane travels in the east-west direction. The location and travel of this crane prevents the crane from carrying loads over the spent fuel pool, thus precluding them from falling into the spent fuel pool.

3.8.4.1.3 Containment Air Baffle

The containment air baffle is located within the upper annulus of the shield building, providing an air flow path for the passive containment cooling system. The air baffle separates the downward air flow entering at the air inlets from the upward air flow that cools the containment vessel and flows out of the discharge stack. The upper portion is supported from the shield building roof and the remainder is supported from the containment vessel. The air baffle is a seismic Category I structure designed to withstand the wind and tornado loads defined in Section 3.3. The air baffle structural configuration is depicted in Figures 1.2-14 and 3.8.4-1. The baffle includes the following sections:

- A wall supported off the shield building roof (see Figure 1.2-14)
- A series of panels attached to the containment vessel cylindrical wall and the knuckle region of the dome
- A sliding plate closing the gap between the wall and the panels fixed to the containment vessel, designed to accommodate the differential movements between the containment vessel and shield building
- Flow guides attached at the bottom of the air baffle to minimize pressure drop

The air baffle is designed to meet the following functional requirements:

- The baffle and its supports are configured to minimize pressure losses as air flows through the system
- The baffle and its supports have a design objective of 60 years
- The baffle and its supports are configured to permit visual inspection and maintenance of the air baffle as well as the containment vessel. Periodic visual inspections are primarily to inspect the condition of the coatings
- The baffle is designed to maintain its function during postulated design basis accidents

- The baffle is designed to maintain its function under specified external events including earthquakes, hurricanes and tornadoes

The design of the containment air baffle is shown in Figure 3.8.4-1. The portion of the air baffle attached to the containment cylinder comprises 60 panels circumferentially in each of seven rows vertically, with each panel subtending an arc of six degrees (approximately 6 feet 11 inches wide). Each panel is supported by horizontal beams spaced approximately 13 feet 8 inches apart. These horizontal beams span the six-degree arc and are bolted to U-shaped attachments welded to the containment vessel. The attachment locations are established considering the containment vessel plate and ring assemblies, as shown in Figure 3.8.2-1. The lowest attachments are at the bottom of the middle containment ring subassembly. The upper attachments are on the head. The attachments can be installed in the subassembly area and, therefore, should not interfere with the containment vessel erection welds. The only penetrations through the containment vessel above the operating deck at elevation 135′-3″ are the main equipment hatch and personnel airlock. Five panels are deleted at the equipment hatch and two flow guides at the personnel airlock.

Two rows of panels are attached to the containment vessel above the cylindrical portion. The panels are curved to follow the curvature of the knuckle region of the head and then become flat forming a conical baffle that provides a transitional flow region into the upper shield building. A vertical sliding plate is provided between this upper row of panels and the air baffle that is attached directly to the shield building roof as shown in sheet 4 of Figure 3.8.4-1. This sliding plate rests on the 12 inch wide horizontal top surface of the upper row of panels. At ambient conditions the vertical sliding plate is approximately centered on the horizontal plate. The sliding plate is set at ambient conditions to permit relative movements from minus 2 inches to plus 3 inches radially and minus 1 inch to plus 4 inches vertically. This accommodates the differential movement between the containment vessel and the shield building, based on the absolute sum of the containment pressure and temperature deflections and of the seismic deflections, such that the integrity of the air baffle is maintained.

The panels accommodate displacements between each panel due to containment pressure and thermal growth. Radial and circumferential growth of the containment vessel are accommodated by slip at the bolts between the horizontal beams and the U shaped attachment resulting in small gaps between adjacent panels. Vertical growth is accommodated by slip between the panel and the horizontal beam supporting the top of the panel. Cover plates between the panels limit leakage during and after occurrence of these differential displacements.

3.8.4.1.4 Seismic Category I Cable Tray Supports

Electric cables are routed in horizontal and vertical steel trays supported by channel type struts made out of cold rolled channel type sections. Spacing of the supports is determined by allowable loads in the trays and stresses in the supports. The supports are attached to the walls, floors, and ceiling of the structures as required by the arrangement of the cable trays. Longitudinal and transverse bracing is provided where required.

3.8.4.1.5 Seismic Category I Heating, Ventilating, and Air Conditioning Duct Supports

Heating, ventilating, and air conditioning duct supports consist of structural steel members or cold rolled channel type sections attached to the walls, floors, and ceiling of the structures as required by the arrangement of the duct. Spacing of the supports is determined by allowable stresses in the duct work and supports. Longitudinal and transverse bracing is provided where required.

3.8.4.2 Applicable Codes, Standards, and Specifications

The following standards are applicable to the design, materials, fabrication, construction, inspection, or testing:

[• *American Concrete Institute (ACI), Code Requirements for Nuclear Safety Related Structures, ACI-349-01*]* (refer to subsection 3.8.4.5 for supplemental requirements)

- American Concrete Institute (ACI), ACI Detailing Manual, 1994

[• *American Institute of Steel Construction (AISC), Specification for the Design, Fabrication and Erection of Steel Safety Related Structures for Nuclear Facilities, AISC-N690-1994*]* (refer to subsection 3.8.4.5 for supplemental requirements)

- American Iron and Steel Institute (AISI), Specification for the Design of Cold Formed Steel Structural Members, Parts 1 and 2, 1996 Edition and 2000 Supplement
- American Welding Society (AWS), Structural Welding Code, AWS D 1.1-2000
- American Welding Society (AWS), Reinforcing Steel Welding Code, AWS D 1.4-98
- National Construction Issues Group (NCIG), Visual Weld Acceptance Criteria for Structural Welding at Nuclear Power Plants, NCIG-01, Revision 2, May 7, 1985

Section 1.9 describes conformance with the Regulatory Guides.

Welding and inspection activities for seismic Category I structural steel, including building structures, structural modules, cable tray supports and heating, ventilating, and air conditioning duct supports are accomplished in accordance with written procedures and meet the requirements of the American Institute of Steel Construction (AISC N-690). The weld acceptance criteria is as defined in NCIG-01 Revision 2. The welded seam of the plates forming part of the leaktight boundary of the spent fuel pool and fuel transfer canal are examined by liquid penetrant and vacuum box after fabrication to confirm that the boundary does not leak.

3.8.4.3 Loads and Load Combinations

3.8.4.3.1 Loads

The loads considered are normal loads, severe environmental loads, extreme environmental loads, and abnormal loads.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

3.8.4.3.1.1 Normal Loads

Normal loads are those loads to be encountered, as specified, during initial construction stages, during test conditions, and later, during normal plant operation and shutdown. They include the following:

D = Dead loads or their related internal moments and forces, including any permanent piping and equipment loads

F = Lateral and vertical pressure of liquids or their related internal moments and forces

L = Live loads or their related internal moments and forces, including any movable equipment loads and other loads that vary with intensity and occurrence

H = Static earth pressure or its related internal moments and forces

T_o = Thermal effects and loads during normal operating or shutdown conditions, based on the most critical transient or steady-state condition

R_o = Piping and equipment reactions during normal operating or shutdown conditions, based on the most critical transient or steady-state condition.

3.8.4.3.1.2 Severe Environmental Loads

The severe environmental load is the following:

W = Loads generated by the design wind specified for the plant in subsection 3.3.1.1

3.8.4.3.1.3 Extreme Environmental Loads

Extreme environmental loads are the following:

E_s = Loads generated by the safe shutdown earthquake specified for the plant, including the associated hydrodynamic and dynamic incremental soil pressure. Loads generated by the safe shutdown earthquake are specified in Section 3.7.

Wt = Loads generated by the design tornado specified for the plant in subsection 3.3.2, including loads due to tornado wind pressure, differential pressure, and tornado-generated missiles.

N = Loads generated by the probable maximum precipitation (provided previously in Table 2.0-1).

3.8.4.3.1.4 Abnormal Loads

Abnormal loads are those loads generated by a postulated high-energy pipe break accident for pipes not qualified for leak-before-break. Abnormal loads include the following:

P_a = Pressure load within or across a compartment generated by the postulated break. The main steam isolation valve (MSIV) and steam generator blowdown valve compartments are designed for a pressurization load of 6 psi. The subcompartment design pressure bounds the pressurization effects due to postulated breaks in high energy pipe. Determination of subcompartment pressure loads is discussed in subsection 6.2.1.2.

T_a = Thermal loads under thermal conditions generated by the postulated break and including T_o. Determination of subcompartment temperatures is discussed in subsection 6.2.1.2.

R_a = Piping and equipment reactions under thermal conditions generated by the postulated break and including R_o. Determination of pipe reactions generated by postulated breaks is discussed in subsection 3.6.

Y_r = Load on the structure generated by the reaction on the broken high-energy pipe during the postulated break. Determination of the loads is discussed in Section 3.6.

Y_j = Jet impingement load on the structure generated by the postulated break. Determination of the loads is discussed in Section 3.6.

Y_m = Missile impact load on the structure generated by or during the postulated break, as from pipe whipping. Determination of the loads is discussed in Section 3.6.

3.8.4.3.1.5 Dynamic Effects of Abnormal Loads

The dynamic effects from the impulsive and impactive loads caused by P_a, R_a, Y_r, Y_j, Y_m, and tornado missiles are considered by one of the following methods:

- Applying an appropriate dynamic load factor to the peak value of the transient load
- Using impulse, momentum, and energy balance techniques
- Performing a time-history dynamic analysis

Elastoplastic behavior may be assumed with appropriate ductility ratios, provided excessive deflections will not result in loss of function of any safety-related system.

Dynamic increase factors appropriate for the strain rates involved may be applied to static material strengths of steel and concrete for purposes of determining section strength.

3.8.4.3.2 Load Combinations

3.8.4.3.2.1 Steel Structures

The steel structures and components are designed according to the elastic working stress design methods of the AISC-N690 specification using the load combinations specified in Table 3.8.4-1.

3.8.4.3.2.2 Concrete Structures

The concrete structures and components are designed according to the strength design methods of ACI-349 Code, using the load combinations specified in Table 3.8.4-2.

3.8.4.3.2.3 Live Load for Seismic Design

Floor live loads, based on requirements during plant construction and maintenance activities, are specified varying from 50 to 250 pounds per square foot (with the exception of the containment operating deck which is designed for 800 pounds per square foot specified for plant maintenance condition).

For the local design of members, such as the floors and beams, seismic loads include the response due to masses equal to 25 percent of the specified floor live loads or 75 percent of the roof snow load, whichever is applicable. These seismic loads are combined with 100 percent of these specified live loads, or 75 percent of the roof snow load, whichever is applicable, except in the case of the containment operating deck. For the seismic load combination, the containment operating deck is designed for a live load of 200 pounds per square foot which is appropriate for plant operating condition. The mass of equipment and distributed systems is included in both the dead and seismic loads.

3.8.4.4 Design and Analysis Procedures

3.8.4.4.1 Seismic Category I Structures

[*The design and analysis procedures for the seismic Category I structures (other than the containment vessel and containment internal structures), including assumptions on boundary conditions and expected behavior under loads, are in accordance with ACI-349 for concrete structures, with AISC-N690 for steel structures, and AISI for cold formed steel structures.]** The structural modules in the auxiliary building are designed using the same procedures as the structural modules in the containment internal structures described in subsection 3.8.3.

[*The criteria of ACI-349, Chapter 12, are applied in development and splicing of the reinforcing steel. The ductility criteria of ACI-349, Chapter 21, are applied in detailing and anchoring of the reinforcing steel.*

The application of Chapter 21 detailing is demonstrated in the reinforcement details of critical sections]* in subsection 3.8.5 and Appendix 3H.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

[*Sections 21.2 through 21.5 of Chapter 21 of ACI 349 are applicable to frame members resisting earthquake effects. These requirements are considered in detailing structural elements subjected to significant flexure and out-of-plane shear. These elements include the following examples described in Appendix 3H*:]*

- Reinforcement details for the shield building roof tension ring are described in subsection 3H.5.6. [*The hoop reinforcement is detailed in accordance with 21.3.3.6 of ACI 349-01. Shear stirrups have T headed anchors at each end. These anchors provide anchorage equivalent to the seismic hooks required in accordance with 21.3.3.4 of ACI 349-01.*]*

- Reinforcement details for the basemat are described in subsection 3.8.5. [*Shear stirrups have T headed anchors at each end.*]*

- Reinforcement details for the exterior walls below grade are described in subsection 3H.5.1.1. [*Shear stirrups have T headed anchors at each end.*]*

[*Sections 21.2 and 21.6 of Chapter 21 of ACI 349 are applicable to walls, diaphragms, and trusses serving as parts of the earthquake force-resisting systems as well as to diaphragms, struts, ties, chords and collector elements. These requirements are considered in the detailing of reinforcement in the walls and floors of the auxiliary building and in the shield building cylindrical wall and roof.*]*

- Reinforcement details for in-plane loads on the shear walls and floors are shown in subsections 3H.5.1 to 3H.5.4. [*Transverse reinforcement terminating at the edges of structural walls or at openings is detailed in accordance with 21.6.6.5 of ACI 349.*]*

- Reinforcement details for shear loads for the column (shear wall) between the air inlets at the top of the shield building cylinder are shown in subsection 3H.5.6.2. [*Horizontal reinforcement terminating at the opening has T headed mechanical anchors at each end as recommended in the commentary to 21.6.6.5 of ACI 349. Through wall shear reinforcement has T headed mechanical anchors at each end which meets the requirements of 21.6.6.5 of ACI 349 as a shear wall and also meets the requirements of 21.4.4.1 and 21.4.4.3 of ACI 349 as a column.*]*

The bases of design for the tornado, pipe breaks, and seismic effects are discussed in Sections 3.3, 3.6, and 3.7, respectively. The foundation design is described in subsection 3.8.5.

The seismic Category I structures are reinforced concrete and structural module shear wall structures consisting of vertical shear/bearing walls and horizontal slabs supported by structural steel framing. Seismic forces are obtained from the equivalent static analysis of the three dimensional finite element models described in Table 3.7.2-14. The out-of-plane bending and shear loads for flexible floors and walls are analyzed using the methodology described in subsections 3.7.2.6 and 3.7.3. These results are modified to account for accidental torsion as described in subsection 3.7.2.11. Where the refinement of these finite element models is insufficient for design of the reinforcement, for example in walls with a large number of openings, detailed finite element models are used. Also evaluated and considered in the shear wall and floor

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

slab design are out-of-plane bending and shear loads, such as live load, dead load, seismic, lateral earth pressure, hydrostatic, hydrodynamic, and wind pressure. These out-of-plane bending and shear loads are obtained from the equivalent static analyses supplemented by hand calculations.

The exterior walls of the seismic Category I structures below the grade are designed to resist the worst case lateral earth pressure loads (static and dynamic), soil surcharge loads, and loads due to external flooding as described in Section 3.4. The lateral earth pressure loads are evaluated for two cases:

- Lateral earth pressure equal to the sum of the static earth pressure plus the dynamic earth pressure calculated in accordance with ASCE 4-98 (Reference 3), Section 3.5.3, Figure 3.5-1, "Variation of Normal Dynamic Soil Pressures for the Elastic Solution"

- Lateral earth pressure equal to the passive earth pressure

The shield building roof and the passive containment cooling water storage tank are analyzed using three-dimensional finite element models with the GTSTRUDL computer codes. The model is shown in Figure 3.8.4-3. It represents one quarter of the roof with symmetric or asymmetric boundary conditions dependent on the applied load. Loads and load combinations are given in subsection 3.8.4.3 and include construction, dead, live, thermal, wind and seismic loads. Seismic loads are applied as equivalent static accelerations. The seismic response of the water in the tank is analyzed in a separate finite element response spectrum analysis with seismic input defined by the floor response spectrum.

The liner for the passive containment cooling water storage system tank is analyzed by hand calculation. The design considers construction loads during concrete placement, loads due to handling and shipping, normal loads including thermal, and the safe shutdown earthquake. Buckling of the liner is prevented by anchoring the liner using the embedded stiffeners and welded studs. The liner is designed as a seismic Category I steel structure in accordance with AISC N690 with the supplemental requirements given in subsection 3.8.4.

The structural steel framing is used primarily to support the concrete slabs and roofs. Metal decking, supported by the steel framing, is used as form work for the concrete slabs and roofs. The structural steel framing is designed for vertical loads. Appendix 3H shows typical structural steel framing in the auxiliary building.

Computer codes used are general purpose computer codes. The code development, verification, validation, configuration control, and error reporting and resolution are according to the quality assurance requirements of Chapter 17.

[*The finned floors for the main control room and the instrumentation and control room ceilings are designed as reinforced concrete slabs in accordance with ACI-349. The steel panels are designed and constructed in accordance with AISC-N690. For positive bending, the steel plate is in tension and the steel plate with fin stiffeners serves as the bottom reinforcement. For negative bending, compression is resisted by the stiffened plate and tension by top reinforcement in the concrete.*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

3.8.4.4.2 Seismic Category I Cable Tray Supports

The design and analysis procedures for seismic Category I cable trays and their supports are described in Appendix 3F.

3.8.4.4.3 Seismic Category I Heating, Ventilating, and Air Conditioning Duct Supports

The design and analysis procedures for seismic Category I heating, ventilating, and air conditioning ducts and their supports are described in Appendix 3A.

3.8.4.5 Structural Criteria

[*The analysis and design of concrete conform to ACI-349. The analysis and design of structural steel conform to AISC-N690. The analysis and design of cold-formed steel structures conform to AISI. The margins of structural safety are as specified by those codes.*]*

3.8.4.5.1 Supplemental Requirements for Concrete Structures

[*Supplemental requirements for ACI-349-01 are given in the position on Regulatory Guide 1.142 in Appendix 1A. The structural design meets the supplemental requirements identified in Regulatory Positions 2 through 8, 10 through 13, and 15.*]*

Paragraph 21.6.1 of ACI 349-01 should reference 21.6.6 instead of 21.6.5. Paragraph 21.6.5 in ACI 349-97 was renumbered to 21.6.6 in ACI 349-01, and the reference in 21.6.1 was not updated. The errata for ACI 349-01 are being updated to include this correction. This makes the paragraph consistent with ACI 349-97, which was endorsed by Regulatory Guide 1.142.

[*Design of fastening to concrete is in accordance with ACI 349-01, Appendix B.*]*

3.8.4.5.2 Supplemental Requirements for Steel Structures

[*Supplemental requirements for use of AISC-N690 are as follows:*

- *In Section Q1.0.2, the definition of secondary stress applies to stresses developed by temperature loading only.*

- *In Section Q1.3, where the structural effects of differential settlement are present, they are included with the dead load, D.*

- *In Table Q1.5.7.1, the stress limit coefficients for compression are as follows:*

  1.3 instead of 1.5 in load combinations 2, 5, and 6.
  1.4 instead of 1.6 in load combinations 7, 8, and 9.
  1.6 instead of 1.7 in load combination 11.

- *In Section Q1.5.8, for constrained members (rotation and/or displacement constraint such that a thermal load causes significant stresses), supporting safety-related structures, systems,*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

or components, the stresses under load combinations 9, 10, and 11 are limited to those allowed in Table Q1.5.7.1 as modified above.

- *Sections Q1.24 and Q1.25.10 are supplemented as follows:*

  Shop painting is in accordance with Section M of the Manual of Steel Construction, Load and Resistance Factor Design, First Edition. Exposed areas after installation are field painted in accordance with the applicable portion of Chapter M of the Manual of Steel Construction, Load and Resistance Factor Design, First Edition.]* See subsection 6.1.2.1 for additional description of the protective coatings.

3.8.4.5.3 Design Summary Report

A design summary report is prepared for seismic Category I structures documenting that the structures meet the acceptance criteria specified in subsection 3.8.4.5.

Deviations from the design due to as-procured or as-built conditions are acceptable based on an evaluation consistent with the methods and procedures of Section 3.7 and 3.8 provided the following acceptance criteria are met.

- the structural design meets the acceptance criteria specified in Section 3.8
- the seismic floor response spectra meet the acceptance criteria specified in subsection 3.7.5.4

Depending on the extent of the deviations, the evaluation may range from documentation of an engineering judgement to performance of a revised analysis and design. The results of the evaluation will be documented in an as-built summary report by the Combined License applicant.

3.8.4.5.4 Design Summary of Critical Sections

[*The design of representative critical elements of the following structures is described in Appendix 3H.*

- *South wall of auxiliary building (column line 1), elevation 66′-6″ to elevation 180′-0″*

- *Interior wall of auxiliary building (column line 7.3), elevation 66′-6″ to elevation 160′-6″*

- *West wall of main control room in auxiliary building (column line L), elevation 117′-6″ to elevation 153′-0″*

- *North wall of MSIV east compartment (column line 11), elevation 117′-6″ to elevation 153′-0″*

- *Shield building cylinder, elevation 160′-6″ to elevation 200′-0″*

- *Roof slab at elevation 180′-0″ adjacent to shield building cylinder*

- *Floor slab on metal decking at elevation 135′-3″*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- *2′-0″ slab in auxiliary building (tagging room ceiling) at elevation 135′-3″*
- *Finned floor in the main control room at elevation 135′-3″*
- *Shield building roof, exterior wall of the PCCS water storage tank*
- *Shield building roof, tension ring and columns between air inlets, elevation 265′-0″ to elevation 276′-0″*
- *Divider wall between the spent fuel pool and the fuel transfer canal*]*

3.8.4.6 Materials, Quality Control, and Special Construction Techniques

This subsection contains information relating to the materials, quality control program, and special construction techniques used in the construction of the other seismic Category I structures, as well as the containment internal structures. The edition of the referenced specifications applicable at the start of construction will be used.

3.8.4.6.1 Materials

3.8.4.6.1.1 Concrete

The compressive strength of concrete used in the seismic Category I structures and containment internal structures is $f_c' = 4000$ psi. The test age of concrete containing pozzolan is 90 days. The test age of concrete without pozzolan is the normal 28 days. Concrete is batched and placed according to Reference 6, Reference 7, and ACI-349.

Portland cement conforms to Reference 8, Type II, with the sum of tricalcium silicate and tricalcium aluminate limited to no more than 58 percent. It is also limited to no more than 0.60 percent by weight of alkalies calculated as Na_2O plus 0.658 K_2O. Certified copies of mill test reports showing that the chemical composition and physical properties conform to the specification are obtained for each cement delivery.

Aggregates conform to Reference 9. The fineness modulus of fine aggregate (sand) is not less than 2.5, nor more than 3.1. In at least four of five successive test samples, such modulus is not allowed to vary more than 0.20 from the moving average established by the last five tests. Coarse aggregates may be rejected if the loss from the Los Angeles abrasion test, Reference 10, using Grading A or Reference 11, exceeds 40 percent by weight at 500 revolutions. Acceptance of source and aggregates is based on the tests specified in Table 3.8.4-3.

Water and ice used in mixing concrete do not contain more than 250 parts per million of chlorides (as Cl) as determined in accordance with Reference 12. They do not contain more than 2000 parts per million of total solids as determined in accordance with Reference 13. Water meets the criteria in Table 3.8.4-4 in regard to the effects of the proposed mixing water on hardened cement pastes and mortars compared with distilled water.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

The concrete contains a pozzolan, an air entraining admixture, and a water-reducing admixture. Admixtures, except pozzolan, are stored in liquid solution.

Admixtures do not contain added chlorides except as contained in potable drinking water used for manufacture of the admixtures. The chloride content is stated in the manufacturer's material certification.

Pozzolan conforms to Reference 14, except that the ignition loss does not exceed 6 percent.

Pozzolan is sampled and tested in accordance with Reference 15 for source approval.

Air entraining admixture conforms to Reference 16 and is the vinsol resin type.

Water-reducing admixture conforms to Reference 17 and is types A and D. Use of types A and D as limited by concrete placing temperature, least dimension of member sizes, and type of placement is as shown in Table 3.8.4-5.

Manufacturer's certification for the air entraining admixture is required demonstrating compliance with Reference 16, Section 4 requirements.

Manufacturer's certification for the water-reducing admixture is required demonstrating compliance with Reference 17, Section 5 requirements.

Manufacturer's test reports are required for each delivery of pozzolan showing the chemical composition and physical properties and certifying that the pozzolan complies with the specification.

Proportioning of the concrete mix is in accordance with Reference 18 and Option B of Reference 6, except that in lieu of the requirements of Reference 6, Paragraph 5.3.1.2, the concrete has a specified slump of 3 inches.

A testing laboratory designs and tests the concrete mixes. Only mixes meeting the design requirements specified for concrete are used.

Forms for concrete are designed as recommended in ACI 347.

3.8.4.6.1.2 Reinforcing Steel

Reinforcing bars for concrete are deformed bars according to Reference 19, Grade 60, and Reference 20. Certified material test reports are provided by the supplier for each heat of reinforcing steel delivered showing physical (both tensile and bend test results) and chemical analysis. In addition, a minimum of one tensile test is performed for each 50 tons of each bar size produced from each heat of steel.

In areas where reinforcing steel splices are necessary and lap splices are not practical, mechanical connections (e.g., threaded splices, swaged sleeves or cadwelds) are used.

Headed reinforcement meeting the requirements of ASTM A970 (Reference 49) is used where mechanical anchorage is required, such as for shear reinforcement in the nuclear island basemat and in the exterior walls below grade.

As stated in subsection 3.4.1.1.1, seismic Category I structures that are located below grade elevation are protected against flooding by a waterproofing system and waterstops. This, in conjunction with the 2 inches of concrete cover for the reinforcing steel, provides sufficient protection for the reinforcing steel. Therefore, the use of coated reinforcing steel is not planned.

3.8.4.6.1.3 Structural Steel

Basic materials used in the structural and miscellaneous steel construction conform to the ASTM standards listed in Table 3.8.4-6.

3.8.4.6.1.4 Masonry Walls

There are no safety-related masonry walls used in the nuclear island.

3.8.4.6.2 Quality Control

The quality assurance program is described in Chapter 17. Conformance to Regulatory Guide 1.94 is as described in Section 1.9.

3.8.4.6.3 Special Construction Techniques

Construction techniques for the structural modules are the same as special construction techniques for the containment internal structures discussed previously in subsection 3.8.3.6.1.

3.8.4.7 Testing and In-Service Inspection Requirements

Structures supporting the passive containment cooling water storage tank on the shield building roof will be examined before and after first filling of the tank.

- The boundaries of the passive containment cooling water storage tank and the tension ring of the shield building roof will be inspected visually for excessive concrete cracking before and after first filling of the tank. Any significant concrete cracking will be documented and evaluated in accordance with ACI 349.3R-96 (reference 50).

- The vertical elevation of the passive containment cooling water storage tank relative to the top of the shield building cylindrical wall at the tension ring will be measured before and after first filling. The change in relative elevation will be compared against the predicted deflection.

- A report will be prepared summarizing the test and evaluating the results.

There are no other in-service testing or inspection requirements for the seismic Category I shield building and auxiliary building. However, during the operation of the plant the condition of these

structures should be monitored by the Combined License applicant to provide reasonable confidence that the structures are capable of fulfilling their intended functions.

3.8.4.8 Construction Inspection

Construction inspection is conducted to verify the concrete wall thickness and quantity of concrete reinforcement. The construction inspection includes concrete wall thickness and reinforcement expressed in units of in^2/ft (linear length) equivalent when compared to standard reinforcement bar sections. Inspections will be measured at applicable sections excluding designed openings or penetrations. Inspections will confirm that each applicable section provides the minimum required reinforcement and concrete thickness as shown in Appendix 3H. The minimum required reinforcement and concrete thickness represents the minimum values to meet the design basis loads. Appendix 3H also indicates the reinforcement provided which may exceed the minimum required reinforcement for the following reasons:

- Structural margin
- Ease of construction
- Use of standardized reinforcement sizes and spacing

3.8.5 Foundations

3.8.5.1 Description of the Foundations

The nuclear island structures, consisting of the containment building, shield building, and auxiliary building are founded on a common 6-foot-thick, cast-in-place, reinforced concrete basemat foundation. The top of the foundation is at elevation 66′-6″.

Adjoining buildings, such as the radwaste building, turbine building, and annex building are structurally separated from the nuclear island structures by a 2-inch gap at and below the grade. A 4-inch minimum gap is provided above grade. This provides space to prevent interaction between the nuclear island structures and the adjacent structures during a seismic event. Figure 3.8.5-1 shows the foundations for the nuclear island structures and the adjoining structures.

Resistance to sliding of the concrete basemat foundation is provided by passive soil pressure and soil friction. This provides the required factor of safety against lateral movement under the most stringent loading conditions.

For ease of construction, the foundation is built on a mud mat. The mud mat is lean, nonstructural concrete and rests upon the load-bearing soil. Waterproofing requirements are described in subsection 3.4.1.1.1.

3.8.5.2 Applicable Codes, Standards, and Specifications

The applicable codes, standards, and specifications are described in subsection 3.8.4.2.

3.8.5.3 Loads and Load Combinations

Loads and load combinations are described in subsection 3.8.4.3. As described in subsection 3.8.2.1.2, the bottom head of the steel containment vessel is the same as the upper head and is capable of resisting the containment internal pressure without benefit of the nuclear island basemat. However, containment pressure loads affect the nuclear island basemat since the concrete is stiffer than the steel head. The containment design pressure is included in the design of the nuclear island basemat as an accident pressure in load combinations 5, 6, and 7 of Table 3.8.4-2. In addition to the load combinations described in subsection 3.8.4.3, the nuclear island is checked for resistance against sliding and overturning due to the safe shutdown earthquake, winds and tornados, and against flotation due to floods and groundwater according to the load combinations presented in Table 3.8.5-1.

3.8.5.4 Design and Analysis Procedures

The seismic Category I structures are concrete, shear-wall structures consisting of vertical shear/bearing walls and horizontal floor slabs. The walls carry the vertical loads from the structure to the basemat. Lateral loads are transferred to the walls by the roof and floor slabs. The walls then transmit the loads to the basemat. The walls also provide stiffness to the basemat and distribute the foundation loads between them.

The design of the basemat consists primarily of applying the design loads to the structures, calculating shears and moments in the basemat, and determining the required reinforcement. For a site with hard rock below the underside of the basemat vertical loads are transmitted directly through the basemat into the rock. Horizontal loads due to seismic are distributed on the underside of the basemat resulting primarily in small membrane forces in the mat. The 6-foot-thick basemat is designed for the upward hydrostatic pressure due to groundwater reduced by the downward deadweight of the mat.

3.8.5.4.1 Analyses for Loads during Operation

The analyses of the basemat use the three-dimensional ANSYS finite element models of the auxiliary building and containment internal structures, which are described in subsection 3.7.2.3 and shown in Figures 3.7.2-1 and 3.7.2-2. The model considers the interaction of the basemat with the overlying structures and with the soil. Provisions are made in the model for two possible uplifts. One is the uplift of the containment internal structures from the lower basemat. The other is the uplift of the basemat from the soil.

The three-dimensional finite element model of the basemat includes the structures above the basemat and their effect on the distribution of loads on the basemat. The finite element models of the auxiliary building above elevation 106′ and the containment internal structures inside containment are reduced to substructures (superelements) within ANSYS. These superelements are then included in the detailed finite model of the basemat, which includes the auxiliary building below elevation 106′ and the mat below the containment vessel. The finite element model of the basemat is shown on sheet 1 of Figure 3.8.5-2. The model of the basemat, including the superelements, is shown on sheet 2.

The subgrade is modeled with one vertical spring and two horizontal springs at each node of the basemat. The vertical springs act in compression only. The horizontal springs are active when the vertical spring is closed and inactive when the vertical spring lifts off. The vertical and horizontal stiffness of the springs represents a rock foundation with a shear wave velocity of 8000 feet per second. Horizontal bearing reactions on the side walls below grade are conservatively neglected.

The nuclear island basemat below the containment vessel, and the containment internal structures basemat above the containment vessel, are simulated with solid tetrahedral elements. Nodes on the two basemats are connected with spring elements normal to the theoretical surface of the containment vessel.

Normal and extreme environmental loads and containment pressure loads are considered in the analysis. The normal loads include dead loads and live loads. Extreme environmental loads include the safe shutdown earthquake.

Dead loads are applied as inertia loads. Live loads and the safe shutdown earthquake loads are applied as concentrated loads on the nodes. The safe shutdown earthquake loads are applied using the assumption that while maximum response from one direction occurs, the responses from the other two directions are 40 percent of the maximum. Combinations of the three directions of the safe shutdown earthquake are considered.

Linear analyses are performed for all specified load combinations assuming that the soil springs can take tension. Critical load cases are then selected for non-linear analyses with basemat liftoff based on the results of the linear cases. The results from the analysis include the forces, shears, and moments in the basemat; the bearing pressures under the basemat; and the area of the basemat that is uplifted. Reinforcing steel areas are calculated from the member forces for each load combination case.

The required reinforcing steel under the shield building is determined by considering both the reinforcement envelope for the linear analyses that do not consider liftoff and the reinforcement envelope for the full non-linear iteration of the most critical load combination cases.

The required reinforcing steel for the portion of the basemat under the auxiliary building is calculated from shears and bending moments in the slab obtained from separate calculations. Beam strip models of the slab segments are loaded with the bearing pressures under the basemat from the three-dimensional finite element analyses. Figure 3.8.5-3 shows the basemat reinforcement.

3.8.5.4.2 Design Summary Report

A design summary report is prepared for the basemat documenting that the structures meet the acceptance criteria specified in subsection 3.8.5.5.

Deviations from the design due to as-procured or as-built conditions are acceptable based on an evaluation consistent with the methods and procedures of Sections 3.7 and 3.8 provided the following acceptance criteria are met.

- The structural design meets the acceptance criteria specified in Section 3.8
- The seismic floor response spectra meet the acceptance criteria specified in subsection 3.7.5.4

Depending on the extent of the deviations, the evaluation may range from documentation of an engineering judgement to performance of a revised analysis and design. The results of the evaluation will be documented in an as-built summary report by the Combined License applicant.

3.8.5.4.3 Design Summary of Critical Sections

The basemat is designed to meet the acceptance criteria specified in subsection 3.8.4.5. Two critical portions of the basemat are identified below together with a summary of their design. The boundaries are defined by the walls and column lines which are shown in Figure 3.7.2-12 (sheet 1 of 12). Table 3.8.5-3 shows the reinforcement required and the reinforcement provided for the critical sections.

[*<u>Basemat between column lines 9.1 and 11 and column lines K and L</u>*

This portion of the basemat is designed as a one way slab spanning a distance of 23′ 6″ between the walls on column lines K and L. The slab is continuous with the adjacent slabs to the east and west. The critical loading is the bearing pressure on the underside of the slab due to dead and seismic loads. This establishes the demand for the top flexural reinforcement at mid span and for the bottom flexural and shear reinforcement at the walls. The basemat is designed for the bearing pressures and membrane forces from the analyses]* described in subsection 3.8.5.4.1. [*Negative moments are redistributed as permitted by ACI 349.*

The top and bottom reinforcement in the east west direction of span are equal. The reinforcement provided is shown in sheets 1, 2 and 5 of Figure 3.8.5-3. Typical reinforcement details showing use of headed reinforcement for shear reinforcement are shown in Figure 3H.5-3.]*

[*<u>Basemat between column lines 1 and 2 and column lines K-2 and N</u>*

This portion of the basemat is designed as a one way slab spanning a distance of 22′ 0″ between the walls on column lines 1 and 2. The slab is continuous with the adjacent slabs to the north and with the exterior wall to the south. The critical loading is the bearing pressure on the underside of the slab due to dead and seismic loads. This establishes the demand for the top flexural reinforcement at mid span and for the bottom flexural and shear reinforcement at wall 2. The basemat is designed for the bearing pressures and membrane forces from the analyses on uniform soil springs]* described in subsection 3.8.5.4.1. [*The reinforcement provided is shown in sheets 1, 2 and 5 of Figure 3.8.5-3. Typical reinforcement details showing use of headed reinforcement for shear reinforcement are shown in Figure 3H.5-3.*]*

Deviations from the design due to as-procured or as-built conditions are acceptable based on an evaluation consistent with the methods and procedures of Sections 3.7 and 3.8 provided the following acceptance criteria are met.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- The structural design meets the acceptance criteria specified in Section 3.8
- The amplitude of the seismic floor response spectra do not exceed the design basis floor response spectra by more than 10 percent

Depending on the extent of the deviations, the evaluation may range from documentation of an engineering judgement to performance of a revised analysis and design.

3.8.5.5 Structural Criteria

The analysis and design of the foundation for the nuclear island structures are according to ACI-349 with margins of structural safety as specified within it. The limiting conditions for the foundation medium, together with a comparison of actual capacity and estimated structure loads, are described in Section 2.5. The minimum required factors of safety against sliding, overturning, and flotation for the nuclear island structures are given in Table 3.8.5-1.

[*The basemat below the auxiliary building is designed for shear in accordance with the provisions for continuous deep flexural members in paragraph 11.8.3 of ACI 349-01. As permitted by paragraph 11.5.5.1 of ACI 349-01, shear reinforcement is not provided when the factored shear force,* V_u*, is less than one half of the shear strength provided by the concrete,* φV_c.]*

3.8.5.5.1 Nuclear Island Maximum Bearing Pressures

The hard rock foundation will be demonstrated to be capable of withstanding the bearing demand from the nuclear island as described in subsection 2.5.4.5.6.

3.8.5.5.2 Flotation

The factor of safety against flotation of the nuclear island is shown in Table 3.8.5-2 and is calculated as follows:

$$\text{F.S.} = \frac{\text{D}}{(\text{F or B})}$$

where:

F.S. = factor of safety against flotation
D = total weight of structures and foundation
F = buoyant force due to the design basis flood
B = buoyant force due to high ground water table

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

3.8.5.5.3 Sliding

The factor of safety against sliding of the nuclear island during a tornado or a design wind is shown in Table 3.8.5-2 and is calculated as follows:

$$F.S. = \frac{F_S + F_P}{F_H}$$

where:

F.S. = factor of safety against sliding from tornado or design wind
F_S = shearing or sliding resistance at bottom of basemat
F_P = maximum soil passive pressure resistance, neglecting surcharge effect
F_H = maximum lateral force due to active soil pressure, including surcharge, and tornado or design wind load

The factor of safety against sliding of the nuclear island during a safe shutdown earthquake is shown in Table 3.8.5-2 and is calculated as follows:

$$F.S. = \frac{F_s + F_p}{F_D + F_H}$$

where:

F.S. = factor of safety against sliding from a safe shutdown earthquake
F_S = shearing or sliding resistance at bottom of basemat
F_P = maximum soil passive pressure resistance, neglecting surcharge effect
F_D = maximum dynamic lateral force, including dynamic active earth pressures
F_H = maximum lateral force due to all loads except seismic loads

The sliding resistance is based on the friction force developed between the basemat and the foundation using a coefficient of friction of 0.55. The effect of buoyancy due to the water table is included in calculating the sliding resistance.

3.8.5.5.4 Overturning

The factor of safety against overturning of the nuclear island during a tornado or a design wind is shown in Table 3.8.5-2 and is calculated as follows:

$$F.S. = \frac{M_R}{M_O}$$

where:

F.S. = factor of safety against overturning from tornado or design wind
M_R = resisting moment
M_O = overturning moment of tornado or design wind

The factor of safety against overturning of the nuclear island during a safe shutdown earthquake is shown in Table 3.8.5-2 and is evaluated using the static moment balance approach assuming overturning about the edge of the nuclear island at the bottom of the basemat. The factor of safety is defined as follows:

$$F.S. = \frac{M_R}{M_O}$$

where:

F.S. = factor of safety against overturning from a safe shutdown earthquake
M_R = nuclear island's resisting moment against overturning
M_O = maximum safe shutdown earthquake induced overturning moment acting on the nuclear island, applied as a static moment

The resisting moment is equal to the nuclear island dead weight, minus buoyant force from ground water table, multiplied by the distance from the edge of the nuclear island to its center of gravity. The overturning moment is the maximum moment about the same edge from the time history analyses of the nuclear island lumped mass stick model described in subsection 3.7.2.

3.8.5.5.5 Effect of Nuclear Island Basemat Uplift on Seismic Response

The effects of basemat uplift were evaluated using an east-west lumped-mass stick model of the nuclear island structures supported on a rigid basemat with nonlinear springs. Floor response spectra from safe shutdown earthquake time history analyses, which included basemat uplift, were compared to those from analyses that did not include uplift. The comparisons showed that the effect of basemat uplift on the floor response spectra is not significant.

3.8.5.6 Materials, Quality Control, and Special Construction Techniques

The materials and quality control program used in the construction of the nuclear island structures foundation are described in subsection 3.8.4.6.

There are no special construction techniques used in the construction of the nuclear island structures foundation. Subsection 2.5.4.5.3 describes information to be provided by the Combined License applicant related to the excavation, backfill, and mudmat.

3.8.5.7 In-Service Testing and Inspection Requirements

There are no in-service testing or inspection requirements for the nuclear island structures foundation.

The need for foundation settlement monitoring is site-specific and is the responsibility of the Combined License applicant (see subsection 2.5.4.6.11).

3.8.5.8 Construction Inspection

Construction inspection is conducted to verify the concrete wall thickness and quantity of concrete reinforcement. The construction inspection includes concrete wall thickness and reinforcement expressed in units of in^2/ft (linear length) equivalent when compared to standard reinforcement bar sections. Inspections will be measured at applicable sections excluding designed openings or penetrations. Inspections will confirm that each section provides the minimum required reinforcement and concrete thickness as shown in Table 3.8.5-3. The minimum required reinforcement and concrete thickness represent the required minimum values to meet the design basis loads. Table 3.8.5-3 also indicates the reinforcement provided which may exceed the required minimum reinforcement for the following reasons:

- Structural margin
- Ease of construction
- Use of standardized reinforcement sizes and spacing

3.8.6 Combined License Information

3.8.6.1 Containment Vessel Design Adjacent to Large Penetrations

The final design of containment vessel elements (reinforcement) adjacent to concentrated masses (penetrations) is completed by the Combined License applicant and documented in the ASME Code design report in accordance with the criteria described in subsection 3.8.2.4.1.2.

3.8.6.2 Passive Containment Cooling System Water Storage Tank Examination

The Combined License applicant will examine the structures supporting the passive containment cooling storage tank on the shield building roof during initial tank filling as described in subsection 3.8.4.7.

3.8.6.3 As-Built Summary Report

The Combined License applicant will evaluate deviations from the design due to as-procured or as-built conditions and will summarize the results of the evaluation in an as-built summary report as described in subsections 3.8.3.5.7, 3.8.4.5.3 and 3.8.5.4.2.

3.8.6.4 In-Service Inspection of Containment Vessel

The Combined License applicant will perform in-service inspection of the containment according to the ASME Code Section XI, Subsection IWE, as described in subsection 3.8.2.7.

3.8.7 References

1. D. Bushnell, "BOSOR5 – Program for buckling of elastic-plastic complex shells of revolution including large deflections and creep," Computers and Structures, Vol. 6, pp 221-239, 1976.

2. C. D. Miller, R. B. Grove, J. G. Bennett, "Pressure Testing of Large Scale Torispherical Heads Subject to Knuckle Buckling," NUREG/CP-0065, Transactions of the International Conference on Structure Mechanics in Reactor Technology, August 1985.

3. "Leak and Structural Test of Personnel Airlock for LWR Containments Subjected to Pressures and Temperatures beyond Design Limits," NUREG/CR-5118, SAND88-7155, May 1989.

4. "Analysis of Bellows Expansion Joints in the Sequoyah Containment," NUREG/CR-5561, SAND90-7020, December 1991.

5. "Severe Accident Testing of Electrical Penetration Assemblies," NUREG/CR-5334, SAND89-0327, November 1989.

6. ASTM C 94, "Specifications for Ready-Mixed Concrete."

7. ACI 304, "Guide for Measuring, Mixing, Transporting, and Placing Concrete."

8. ASTM C 150, "Specification for Portland Cement."

9. ASTM C 33, "Specification for Concrete Aggregates."

10. ASTM C 131, "Resistance to Abrasion of Small Size Coarse Aggregate by Use of the Los Angeles Machine."

11. ASTM C 535, "Test Method for Resistance to Degradation of Large-Size Coarse Aggregate by Abrasion and Impact in the Los Angeles Machine."

12. ASTM D 512, "Chloride Ion in Industrial Water."

13. ASTM D 1888, "Particulate and Dissolved Matter in Industrial Water."

14. ASTM C 618, "Fly Ash and Raw or Calcined Natural Pozzolans for Use in Portland Cement Concrete."

15. ASTM C 311, "Sampling and Testing Fly Ash or Natural Pozzolans for Use as Mineral Admixture in Portland Cement Concrete."

16. ASTM C 260, "Air Entraining Admixtures for Concrete."

17. ASTM C 494, "Chemical Admixtures for Concrete."

18. ACI 211.1, "Standard Practice for Selecting Proportions for Normal, Heavy Weight, and Mass Concrete."

19. ASTM A 615, "Deformed and Plain Billet Steel Bars for Concrete Reinforcement."

20. ASTM A 706, "Low Alloy Steel Deformed Bars for Concrete Reinforcement."

21. ANSYS Engineering Analysis User's Manual, Releases up to and including ANSYS 5.7, ANSYS Inc.

22. D. Bushnell, "Elastic-Plastic Buckling of Internally Pressurized Ellipsoidal Pressure Vessel Heads," Welding Research Council Bulletin 267, May 1981.

23. J. G. Bennett, "An Assessment of Loss-of-Containment Potential Because of Knuckle Buckling for 4:1 Steel Containment Heads," NUREG/CR-4926, LA-10972-MS, April 1987. (This Report also includes the Contractor's Report: "Buckling and Rupture Tests of Two Fabricated Torispherical Heads under Internal Pressure," by R. B. Grove, S. W. Peters, C. D. Miller, and M. F. Eder, C.B.I. Industries, Inc. Research Laboratory.)

24. D. Bushnell, "Stress, Stability, and Vibration of Complex Branched Shells of Revolution: Analysis and User's Manual for BOSOR-4," LMSC-D243605, Lockheed Missiles and Space, Palo Alto, Cal., 1972.

25. "Evaluation of Seals for Mechanical Penetrations of Containment Buildings," NUREG/CR-5096 SAND88-7016.

26. "Experimental Results from Containment Piping Bellows Subjected to Severe Accident Conditions," NUREG/CR-6154, SAND94-1711, Vol. 1, September 1994.

27. H. Akiyama, H. Sekimoto, M. Tanaka, K. Inoue, M. Fukihara, Y. Okuda, "1/10th Scale Model Test of Inner Concrete Structure Composed of Concrete Filled Steel Bearing Wall," 10th International Conference on Structural Mechanics in Reactor Technology, 1989.

28. H. Akiyama, H. Sekimoto, M. Fukihara, K. Nakanashi, K. Hara, "A Compression and Shear Loading Test of Concrete Filled Steel Bearing Wall," 11th International Conference on Structural Mechanics in Reactor Technology, 1991.

29. T. Fukumoto, B. Kato, et al., "Concrete Filled Steel Bearing Walls," IABSE Symposium, Paris-Versailles, 1987.

30. P. F. Adams, T. J. E. Zimmerman, "Design and Behaviour of Composite Ice-Resisting Walls," "Steel/Concrete Composite Structural Systems," C-FER Publication No. 1, Proceedings of a special symposium held in conjunction with POAC '87, Fairbanks, Alaska, 9th International Conference on Port and Ocean Engineering under Arctic Conditions, 1987.

31. B. O'Flynn, J. G. MacGregor, "Tests on Composite Ice-Resisting Walls," "Steel/Concrete Composite Structural Systems," C-FER Publication No. 1, Proceedings of a special symposium held in conjunction with POAC '87, Fairbanks, Alaska, 9th International Conference on Port and Ocean Engineering under Arctic Conditions, 1987.

32. F. Ohno, T. Shioya, Y. Nagasawa, G. Matsumoto, T. Okada, T. Ota, "Experimental Studies on Composite Members for Arctic Offshore Structures," "Steel/Concrete Composite Structural Systems," C-FER Publication No. 1, Proceedings of a special symposium held in conjunction with POAC '87, Fairbanks, Alaska, 9th International Conference on Port and Ocean Engineering under Arctic Conditions, 1987.

33. M. Matsuishi, S. Iwata, "Strength of Composite System Ice-Resisting Structures," "Steel/Concrete Composite Structural Systems," C-FER Publication No. 1, Proceedings of a special symposium held in conjunction with POAC '87, Fairbanks, Alaska, 9th International Conference on Port and Ocean Engineering under Arctic Conditions, 1987.

34. Fitch, J. R. et al., "Source Load Approach to Evaluate Boiling Water Reactor Pressure Suppression Containment Loads," Proceedings Eighth SMIRT, Paper J 7/3, 1985.

35. WCAP-13891, Revision 0 (Proprietary) and WCAP-14095, Revision 0 (Non-Proprietary), AP600 Automatic Depressurization System Phase A Test Data Report, May 1994.

36. WCAP-14324, Revision 0 (Proprietary) and WCAP-14325, Revision 0 (Non-Proprietary), Final Data Report for ADS Phase B1 Tests, April 1995.

37. De Salvo G. J., Gorwan A. W., ANSYS Engineering Analysis System User's Manual Revision 4.4 (including Revision 4.4.A) May 30, 1990.

38. M. P. Collins, D. Mitchell, P. Adebar, F. J. Vecchio, "General Shear Design Method," ACI Structural Journal, Vol 93, No. 1, January - February 1996.

39. Bhide and Collins, "Influence of Axial Tension on the Shear Capacity of Reinforced Concrete Members," ACI Structural Journal, September-October 1989.

40. K. Sorensen, O. Loset and T. O. Olsen, "Investigations of the Influence of Axial Tensile Forces on the Transverse Shear Strength," Report No. PP1-1-5, Det Norske Veritas, Oslo, June 1981.

41. S. B. Bhide and M. P. Collins, "Reinforced Concrete Elements in Shear and Tension," Publication No. 87-02, Department of Civil Engineering, University of Toronto, January 1987.

42. P. E. Adebar, "Shear Design of Concrete Offshore Structures," Doctoral Thesis in the University of Toronto, 1989.

43. M. W. Kani, M. W. Huggins, R. R. Wittkopp, "Kani on Shear and Torsion in Reinforced Concrete," Department of Civil Engineering, University of Toronto, 1979.

44. "Guide to Stability Design Criteria for Metal Structures," edited by B. G. Johnston, 3rd Edition.

45. Bressler, Lin and Scalzi, "Design of Steel Structures," Second Edition.

46. Deleted.

47. Deleted.

48. Deleted.

49. ASTM A 970, "Specification for Welded Headed Bars for Concrete Reinforcement."

50. ACI 349.3R-96, "Evaluation of Existing Nuclear Safety-Related Concrete Structures."

51. Letter DCP/NRC 1340, April 7, 1998 from Brian A. McIntyre, Westinghouse Electric Company, to T. R. Quay, Nuclear Regulatory Commission, Enclosure 1.

52. WCAP-15613, Revision 0 (Proprietary) and WCAP-15706, Revision 0 (Non-Proprietary), AP1000 PIRT and Scaling Assessment, March 2001.

Table 3.8.2-1

LOAD COMBINATIONS AND SERVICE LIMITS FOR CONTAINMENT VESSEL

Load Description		Load Combination and Service Limit										
		Con	**Test**	**Des.**	**Des.**	**A**	**A**	**A**	**C**	**D**	**C**	**D**
Dead	D	x	x	x	x	x	x	x	x	x	x	x
Live	L	x	x	x	x	x	x	x	x	x	x	x
Wind	W	x				x						
Safe shutdown earthquake	E_s								x	x		x
Tornado	W_t										x	
Test pressure	P_t		x									
Test temperature	T_t		x									
Operating pressure	P_o					x					x	
Design pressure	P_d			x			x		x			x
External pressure (2.9 psid)	P_e				x			x		x		
Normal reaction	R_o				x	x		x		x	x	
Normal thermal	T_o				x	x		x		x	x	
Accident thermal reactions	R_a			x			x		x			x
Accident thermal	T_a			x			x		x			x
Accident pipe reactions	Y_r											x
Jet impingement	Y_j											x
Pipe impact	Y_m											x

Notes:
1. Service limit levels are per ASME-NE.
2. Where any load reduces the effects of other loads, that load is to be taken as zero, unless it can be demonstrated that the load is always present or occurs simultaneously with the other loads.

Table 3.8.2-2

CONTAINMENT VESSEL PRESSURE CAPABILITIES

Containment Element		Pressure Capability				
		Deterministic Severe Accident Capacity[1]			Maximum Pressure Capability[2]	
Temperature		100°F	300°F	400°F	100°F	400°F
Cylinder		135 psig	117 psig	112 psig	155 psig	129 psig
Ellipsoidal Head		104 psig	91 psig	87 psig	174 psig	144 psig
16-foot equipment hatch	F.S. = 1.67	126 psig	121 psig	118 psig	210 psig	198 psig
	F.S. = 2.50	84 psig	81 psig	79 psig		
Personnel airlocks[3]		>163 psig	>163 psig	>163 psig	>300 psig	>300 psig

Notes:
1. The buckling capacity of the ellipsoidal head is taken as 60 percent of the critical buckling pressure calculated by the BOSOR-5 nonlinear analyses; the buckling capacity at higher temperatures is calculated by reducing the capacity at 100°F by the ratio of yield at 100°F to yield at the higher temperature. Evaluations of the equipment hatch covers are shown both for ASME paragraph NE-3222 (F.S. = 2.50) and Code Case N-284 (F.S. = 1.67). Evaluations of the other elements are according to ASME Service Level C.
2. The estimated maximum pressure capability is based on minimum specified material properties.
3. The capacities of the personnel airlocks are estimated from test results.

Table 3.8.2-3

ANALYSIS AND TEST RESULTS OF FABRICATED HEADS (REFERENCE 23)

	Test Model #1	**Test Model #2**
Cylinder radius	96.0 inches	96.0 inches
Knuckle radius	32.64 inches	32.64 inches
Spherical radius	172.8 inches	172.8 inches
Thickness	0.196 inches	0.27 inches
Head height/radius	0.5	0.5
Radius/thickness	490	356
Test initial buckling pressure	58 psig	106 psig
Test collapse pressure	229 psig	332 psig
Collapse pressure/initial buckling pressure	3.95	3.13
BOSOR-5 predicted buckling pressure	73.6 psig	106.6 psig

Table 3.8.2-4

SUMMARY OF CONTAINMENT VESSEL MODELS AND ANALYSIS METHODS

Model	Analysis Method	Program	Purpose
Axisymmetric shell	Modal analysis	ANSYS	To calculate frequencies and mode shapes for comparison against stick model
Lumped mass stick model	Modal analysis	ANSYS	To create equivalent stick model for use in nuclear island seismic analyses
Axisymmetric shell	Static analyses using Fourier harmonic loads	ANSYS	To calculate containment vessel shell stresses
Axisymmetric shell	Nonlinear bifurcation	BOSOR5	To calculate buckling capacity close to base under thermal loads To calculate pressure capacity of top head
Finite element shell	Linear bifurcation	ANSYS	To study local effect of large penetrations and embedment on buckling capacity for axial and external pressure loads
Finite element shell	Modal analysis	ANSYS	To calculate frequencies and mode shapes for local effects of equipment hatches and personnel airlocks
Finite element shell	Static analyses	ANSYS	To calculate local shell stress in vicinity of the equipment hatches and personnel airlocks

Table 3.8.3-1

SHEAR AND FLEXURAL STIFFNESSES OF STRUCTURAL MODULE WALLS

Case	Analysis Assumption	Shear Stiffness(1),(2)				Flexural Stiffness(1),(2)			
		48" Wall		30" Wall		48" Wall		30" Wall	
		GA $x 10^6$ lbs	Ratio	GA $x 10^6$ lbs	Ratio	EI $x 10^9$ lbs. in^2	Ratio	EI $x 10^9$ lbs. in^2	Ratio
1	Monolithic section considering steel plates and uncracked concrete. For shear stiffness this is ($A_c G_c + A_s G_s$).	83.5	1.0	55.8	1.0	47.5	1.0	13.6	1.0
2	Uncracked gross concrete section (full wall thickness considering steel plate as concrete)	73.9	0.89	46.2	0.83	33.2	0.70	8.1	0.60
3	Transformed cracked section considering steel plates and concrete (no concrete tension stiffness)	25.0	0.30	22.6	0.41	22.1	0.47	8.0	0.59

Notes:
1. The shear stiffness, GA, is calculated for the full thickness of wall. The flexural stiffness is calculated per unit length of the wall.
2. Stiffness calculations are based on the following material properties: E_c = 3,605,000 psi,n = 8, v_c = 0.17, v_s = 0.30

Table 3.8.3-2

SUMMARY OF CONTAINMENT INTERNAL STRUCTURES MODELS AND ANALYSIS METHODS

Computer Program and Model	Analysis Method	Purpose	Concrete Stiffness [1]
3D ANSYS finite element of containment internal structures fixed at elevation 98′-0″	Equivalent static analysis	To obtain the in-plane and out-of-plane seismic forces for the design of floors and walls	Monolithic Case 1
3D ANSYS finite element of containment internal structures fixed at elevation 98′-0″	Static analyses	To obtain member forces in boundaries of IRWST for static loads (dead, live, hydrostatic, pressure)	Monolithic Case 1
3D ANSYS finite element of containment internal structures fixed at elevation 98′-0″	Static analyses	To obtain member forces in boundaries of IRWST for thermal loads	Cracked Case 3
The following AP600 analyses are used as background to develop the AP1000 design loads.			
3D ANSYS finite element of containment internal structures fixed at elevation 103′-0″	Harmonic analyses	To evaluate natural frequencies potentially excited by hydrodynamic loads	Uncracked Case 2
	Time history analyses	To obtain dynamic response of IRWST boundary for hydrodynamic loads	Monolithic and cracked Cases 1 & 3

Note:
1. See Table 3.8.3-1 for stiffness case description.

Table 3.8.3-3

[*DEFINITION OF CRITICAL LOCATIONS AND THICKNESSES FOR CONTAINMENT INTERNAL STRUCTURES*(1)]*

Wall Description	***Applicable Column Lines***	***Applicable Elevation Range***	***Concrete Thickness*(2)**	***Required Thickness of Surface Plates (inches)*(3)**	***Thickness of Surface Plates Provided (inches)*(4)**
Containment Structures					
Module Wall 1	*West wall of refueling cavity*	*Wall separating IRWST and refueling cavity from elevation 103' to 135'-3"*	*4'-0" concrete-filled structural wall module with 0.5-in.-thick steel plate on inside and outside of wall*	*0.11*	*0.5*
Module Wall 2	*South wall of west steam generator cavity*	*Wall separating IRWST and west steam generator cavity from elevation 103' to 135'-3"*	*2'-6" concrete-filled structural wall module with 0.5-in.-thick steel plate on inside and outside of wall*	*0.42*	*0.5*
CA02 Module Wall	*North east boundary wall of IRWST*	*Wall separating IRWST and maintenance floor from elevation 103' to 135'-3"*	*2'-6" concrete-filled structural wall module with 0.5-in.-thick steel plate on inside and outside of wall*	*0.24*	*0.5*

Notes:

1. *The applicable column lines and elevation levels are identified and included in Figures 1.2-9, 3.7.2-12 (sheets 1 through 12), 3.7.2-19 (sheets 1 through 3) and on Table 1.2-1.*
2. *The concrete thickness includes the steel face plates. Thickness greater than 3'-0" have a construction tolerance of +1", -3/4". Thickness less than or equal to 3'-0" have a construction tolerance of +1/2", -3/8".*
3. *These plate thicknesses represent the minimum thickness required for operating and design basis loads except for designed openings or penetrations. These values apply for each face of the applicable wall unless specifically indicated on the table.*
4. *These plate thicknesses represent the thickness provided for operating and design basis loads except for designed openings or penetrations. These values apply for each face of the applicable wall unless specifically indicated on the table.*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.8.3-4 (Sheet 1 of 3)

[*DESIGN SUMMARY OF WEST WALL OF REFUELING CANAL DESIGN LOADS, LOAD COMBINATIONS, AND COMPARISON TO ACCEPTANCE CRITERIA MID-SPAN AT MID-HEIGHT*]*

Load/Comb.	*TX*	*TY*	*TXY*	*MX*	*MY*	*MXY*	*NX*	*NY*	*Comments*
	k/ft	*k/ft*	*k/ft*	*kft/ft*	*kft/ft*	*kft/ft*	*k/ft*	*k/ft*	
Dead (D)	*-1*	*-17*	*0*	*2*	*2*	*0*	*0*	*1*	–
Hydro (F)	*1*	*0*	*2*	*24*	*30*	*-2*	*0*	*0*	–
Live (L)	*0*	*-8*	*0*	*3*	*3*	*0*	*0*	*1*	*During refueling*
Live (L_o)	*0*	*-2*	*0*	*1*	*1*	*0*	*0*	*0*	*During operation*
Live (ADS)	*0*	*6*	*4*	*19*	*21*	*-3*	*0*	*1*	–
E_s	*10*	*16*	*71*	*15*	*10*	*16*	*1*	*2*	–
Thermal (T_o)	*-269*	*-125*	*-59*	*517*	*506*	*-15*	*10*	*-14*	–
LC (1)	*-1*	*-17*	*9*	*70*	*81*	*-9*	*0*	*3*	$1.4D+1.4F+1.7L_o+1.7ADS$
LC (2)	*-1*	*-37*	*2*	*43*	*49*	*-3*	*0*	*2*	$1.4D+1.4F+1.7Lr$
LC (3)	*-1*	*-13*	*8*	*69*	*80*	*-9*	*0*	*3*	$1.4D+1.4F+1.7ADS$
LC (4)	*10*	*4*	*77*	*61*	*64*	*17*	*2*	*4*	$D+F+L_o + \|ADS\|+E_s$
LC (5)	*-11*	*-42*	*-73*	*-6*	*1*	*-21*	*-1*	*-3*	$D+F+L_o - \|ADS\|-E_s$
LC (6)	*-259*	*-121*	*18*	*577*	*570*	*2*	*12*	*-9*	$D+F+L_o + \|ADS\|+T_o+E_s$
LC (7)	*-281*	*-166*	*-132*	*511*	*507*	*-36*	*9*	*-16*	$D+F+L_o - \|ADS\|+T_o-E_s$
LC (8)	*10*	*7*	*76*	*60*	*63*	*10*	*1*	*4*	$0.9D+1.0F+1.0ADS+1.0E_s$

Notes:
x-direction is horizontal, y-direction is vertical.
element number 1870

Plate thickness required for load combinations excluding thermal:	*0.08 inches*
Plate thickness provided:	*0.50 inches*
Maximum principal stress for load combinations 6 and 7 including thermal:	*26.9 ksi*
Yield stress at temperature:	*55.0 ksi*
Maximum stress intensity range for load combinations 6 and 7 including thermal:	*26.9 ksi*
Allowable stress intensity range for load combinations 6 and 7 including thermal:	*110.0 ksi*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.8.3-4 (Sheet 2 of 3)

[*DESIGN SUMMARY OF WEST WALL OF REFUELING CANAL DESIGN LOADS, LOAD COMBINATIONS, AND COMPARISON TO ACCEPTANCE CRITERIA MID-SPAN AT BASE*]*

Load/Comb.	*TX* k/ft	*TY* k/ft	*TXY* k/ft	*MX* kft/ft	*MY* kft/ft	*MXY* kft/ft	*NX* k/ft	*NY* k/ft	*Comments*
Dead (D)	-3	-24	-1	0	-2	0	0	0	–
Hydro (F)	1	-1	4	-2	-40	-1	-1	16	–
Live (L)	-1	-7	0	0	-3	0	0	1	*During refueling*
Live (L_o)	0	-2	0	0	-1	0	0	0	*During operation*
Live (ADS)	1	4	5	-2	-29	-1	-1	10	–
E_s	11	24	78	8	50	3	3	8	–
Thermal (T_o)	-457	-72	-114	607	627	-12	-10	-21	–
LC (1)	-3	-31	13	-6	-111	-3	-3	41	$1.4D+1.4F+1.7L_o+1.7ADS$
LC (2)	-5	-46	5	-4	-65	-2	-2	25	$1.4D+1.4F+1.7Lr$
LC (3)	-2	-28	12	-6	-109	-3	-3	40	$1.4D+1.4F+1.7ADS$
LC (4)	8	1	86	7	36	2	3	35	$D+F+L_o + \|ADS\|+E_s$
LC (5)	-14	-54	-79	-12	-122	-5	-5	0	$D+F+L_o - \|ADS\|-E_s$
LC (6)	-448	-71	-28	614	662	-10	-7	14	$D+F+L_o + \|ADS\|+T_o+E_s$
LC (7)	-470	-127	-193	596	504	-17	-15	-21	$D+F+L_o - \|ADS\|+T_o-E_s$
LC (8)	9	5	86	3	-22	0	1	34	$0.9D+1.0F+1.0ADS+1.0E_s$

Notes:
x-direction is horizontal, y-direction is vertical.
element number 1788

Plate thickness required for load combinations excluding thermal:	*0.05 inches*
Plate thickness provided:	*0.50 inches*
Maximum principal stress for load combinations 6 and 7 including thermal:	*31.8 ksi*
Yield stress at temperature:	*55.0 ksi*
Maximum stress intensity range for load combinations 6 and 7 including thermal:	*32.9 ksi*
Allowable stress intensity range for load combinations 6 and 7 including thermal:	*110.0 ksi*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.8.3-4 (Sheet 3 of 3)

[*DESIGN SUMMARY OF WEST WALL OF REFUELING CANAL DESIGN LOADS, LOAD COMBINATIONS, AND COMPARISON TO ACCEPTANCE CRITERIA NORTH END BOTTOM CORNER*]*

Load/Comb.	TX	TY	TXY	MX	MY	MXY	NX	NY	Comments
	k/ft	k/ft	k/ft	kft/ft	kft/ft	kft/ft	k/ft	k/ft	
Dead (D)	-4	-22	-2	-1	-2	0	0	0	–
Hydro (F)	2	0	5	-10	-16	3	1	3	–
Live (L)	-1	-4	0	0	-1	0	0	0	During refueling
Live (L_o)	0	-2	0	0	0	0	0	0	During operation
Live (ADS)	1	1	3	-7	-14	2	1	2	–
E_s	13	29	77	15	71	6	5	7	–
Thermal (T_o)	-435	-254	89	628	360	-30	9	74	–
LC (1)	-2	-31	9	-27	-49	8	4	8	$1.4D+1.4F+1.7L_o+1.7ADS$
LC (2)	-5	-37	4	-16	-26	5	2	5	$1.4D+1.4F+1.7Lr$
LC (3)	-2	-28	9	-27	-49	8	4	8	$1.4D+1.4F+1.7ADS$
LC (4)	11	7	82	11	67	12	8	12	$D+F+L_o + \|ADS\|+E_s$
LC (5)	-16	-53	-78	-33	-103	-5	-5	-6	$D+F+L_o - \|ADS\|-E_s$
LC (6)	-424	-246	172	639	427	-19	16	86	$D+F+L_o + \|ADS\|+T_o+E_s$
LC (7)	-451	-307	12	595	256	-35	4	69	$D+F+L_o - \|ADS\|+T_o-E_s$
LC (8)	12	11	83	-2	39	12	7	12	$0.9D+1.0F+1.0ADS+1.0E_s$

Notes:
x-direction is horizontal, y-direction is vertical.
element number 1794

Plate thickness required for load combinations excluding thermal: 0.08 inches
Plate thickness provided: 0.50 inches

Maximum principal stress for load combinations 6 and 7 including thermal: 27.8 ksi
Yield stress at temperature: 55.0 ksi

Maximum stress intensity range for load combinations 6 and 7 including thermal: 28.9 ksi
Allowable stress intensity range for load combinations 6 and 7 including thermal: 110.0 ksi

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.8.3-5 (Sheet 1 of 3)

[DESIGN SUMMARY OF SOUTH WALL OF STEAM GENERATOR COMPARTMENT DESIGN LOADS, LOAD COMBINATIONS, AND COMPARISON TO ACCEPTANCE CRITERIA MID-SPAN AT MID-HEIGHT]*

Load/Comb.	*TX*	*TY*	*TXY*	*MX*	*MY*	*MXY*	*NX*	*NY*	*Comments*
	k/ft	*k/ft*	*k/ft*	*kft/ft*	*kft/ft*	*kft/ft*	*k/ft*	*k/ft*	
Dead (D)	*0*	*-19*	*0*	*1*	*0*	*0*	*0*	*0*	–
Hydro (F)	*-2*	*2*	*-4*	*20*	*22*	*0*	*0*	*-1*	–
Live (L)	*0*	*-8*	*0*	*2*	*0*	*0*	*0*	*0*	*During refueling*
Live (L_o)	*0*	*-3*	*0*	*0*	*0*	*0*	*0*	*0*	*During operation*
Live (ADS)	*-1*	*9*	*-8*	*16*	*16*	*-1*	*0*	*1*	–
E_s	*13*	*60*	*57*	*40*	*30*	*7*	*1*	*5*	–
Thermal (T_o)	*-199*	*-196*	*7*	*406*	*392*	*14*	*-5*	*-6*	–
LC (1)	*-6*	*-15*	*-19*	*58*	*58*	*-1*	*1*	*1*	$1.4D+1.4F+1.7L_o+1.7ADS$
LC (2)	*-3*	*-38*	*-6*	*33*	*31*	*-1*	*1*	*0*	$1.4D+1.4F+1.7Lr$
LC (3)	*-6*	*-10*	*-19*	*57*	*58*	*-1*	*1*	*1*	$1.4D+1.4F+1.7ADS$
LC (4)	*12*	*48*	*60*	*78*	*68*	*7*	*2*	*5*	$D+F+L_o + \|ADS\|+E_s$
LC (5)	*-17*	*-88*	*-69*	*-34*	*-25*	*-8*	*-1*	*-6*	$D+F+L_o - \|ADS\|-E_s$
LC (6)	*-187*	*-148*	*67*	*484*	*460*	*21*	*-3*	*-1*	$D+F+L_o + \|ADS\|+T_o+E_s$
LC (7)	*-216*	*-285*	*-61*	*372*	*367*	*6*	*-6*	*-12*	$D+F+L_o - \|ADS\|+T_o-E_s$
LC (8)	*9*	*53*	*45*	*77*	*68*	*6*	*2*	*5*	$0.9D+1.0F+1.0ADS+1.0E_s$

Notes:
x-direction is horizontal, y-direction is vertical.
element number 4228

Plate thickness required for load combinations excluding thermal: *0.14 inches*
Plate thickness provided: *0.50 inches*

Maximum principal stress for load combinations 6 and 7 including thermal: *33.6 ksi*
Yield stress at temperature: *36.0 ksi*

Maximum stress intensity range for load combinations 6 and 7 including thermal: *33.6 ksi*
Allowable stress intensity range for load combinations 6 and 7 including thermal: *72.0 ksi*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.8.3-5 (Sheet 2 of 3)

[*DESIGN SUMMARY OF SOUTH WALL OF STEAM GENERATOR COMPARTMENT DESIGN LOADS, LOAD COMBINATIONS, AND COMPARISON TO ACCEPTANCE CRITERIA MID-SPAN AT BASE*]*

Load/Comb.	*TX*	*TY*	*TXY*	*MX*	*MY*	*MXY*	*NX*	*NY*	*Comments*
	k/ft	*k/ft*	*k/ft*	*kft/ft*	*kft/ft*	*kft/ft*	*k/ft*	*k/ft*	
Dead (D)	-3	-23	0	0	0	0	0	0	–
Hydro (F)	1	3	-9	-4	-38	0	0	15	–
Live (L)	-1	-8	-1	0	-1	0	0	0	*During refueling*
Live (L_o)	0	-3	0	0	0	0	0	0	*During operation*
Live (ADS)	1	8	-10	-3	-27	0	0	9	–
E_s	11	66	47	14	98	1	1	21	–
Thermal (T_o)	-464	-83	89	424	446	12	12	-3	–
LC (1)	-1	-20	-31	-10	-99	-1	-1	36	$1.4D+1.4F+1.7L_o+1.7ADS$
LC (2)	-5	-42	-15	-5	-54	-1	0	21	$1.4D+1.4F+1.7Lr$
LC (3)	-1	-15	-30	-10	-99	-1	-1	36	$1.4D+1.4F+1.7ADS$
LC (4)	10	50	47	13	88	1	1	45	$D+F+L_o + \|ADS\|+E_s$
LC (5)	-15	-98	-67	-20	-163	-2	-2	-15	$D+F+L_o - \|ADS\|-E_s$
LC (6)	-454	-33	137	437	534	13	13	42	$D+F+L_o + \|ADS\|+T_o+E_s$
LC (7)	-480	-182	22	404	283	10	10	-18	$D+F+L_o - \|ADS\|+T_o-E_s$
LC (8)	11	56	28	7	33	0	1	45	$0.9D+1.0F+1.0ADS+1.0E_s$

Notes:
x-direction is horizontal, y-direction is vertical.
element number 1943

Plate thickness required for load combinations excluding thermal: *0.16 inches*
Plate thickness provided: *0.50 inches*

Maximum principal stress for load combinations 6 and 7 including thermal: *42.3 ksi*
Yield stress at temperature: *36.0 ksi*

Maximum stress intensity range for load combinations 6 and 7 including thermal: *42.3 ksi*
Allowable stress intensity range for load combinations 6 and 7 including thermal: *72.0 ksi*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.8.3-5 (Sheet 3 of 3)

[*DESIGN SUMMARY OF SOUTH WALL OF STEAM GENERATOR COMPARTMENT DESIGN LOADS, LOAD COMBINATIONS, AND COMPARISON TO ACCEPTANCE CRITERIA WEST END BOTTOM CORNER*]*

Load/Comb.	*TX k/ft*	*TY k/ft*	*TXY k/ft*	*MX kft/ft*	*MY kft/ft*	*MXY kft/ft*	*NX k/ft*	*NY k/ft*	*Comments*
Dead (D)	*-5*	*-32*	*2*	*-1*	*3*	*0*	*-1*	*-2*	–
Hydro (F)	*3*	*12*	*-9*	*-6*	*-13*	*3*	*1*	*3*	–
Live (L)	*-2*	*-14*	*1*	*0*	*1*	*0*	*0*	*-1*	*During refueling*
Live (L_o)	*-1*	*-6*	*0*	*0*	*1*	*0*	*0*	*-1*	*During operation*
Live (ADS)	*5*	*25*	*-9*	*-4*	*-11*	*2*	*2*	*2*	–
E_s	*42*	*247*	*52*	*11*	*88*	*3*	*12*	*34*	–
Thermal (T_o)	*-409*	*-276*	*259*	*398*	*669*	*12*	*-38*	*-179*	–
LC (1)	*5*	*3*	*-25*	*-16*	*-30*	*8*	*3*	*4*	$1.4D+1.4F+1.7L_o+1.7ADS$
LC (2)	*-6*	*-51*	*-9*	*-10*	*-11*	*5*	*0*	*-1*	$1.4D+1.4F+1.7Lr$
LC (3)	*6*	*14*	*-24*	*-16*	*-32*	*8*	*4*	*5*	$1.4D+1.4F+1.7ADS$
LC (4)	*44*	*245*	*54*	*7*	*90*	*8*	*14*	*36*	$D+F+L_o + /ADS/+E_s$
LC (5)	*-50*	*-298*	*-68*	*-21*	*-107*	*-1*	*-13*	*-36*	$D+F+L_o - /ADS/-E_s$
LC (6)	*-364*	*-31*	*313*	*406*	*759*	*21*	*-24*	*-143*	$D+F+L_o + /ADS/+T_o+E_s$
LC (7)	*-459*	*-574*	*192*	*377*	*561*	*11*	*-51*	*-215*	$D+F+L_o - /ADS/+T_o-E_s$
LC (8)	*46*	*255*	*36*	*0*	*67*	*8*	*14*	*37*	$0.9D+1.0F+1.0ADS+1.0E_s$

Notes:
x-direction is horizontal, y-direction is vertical.
element number 1933

Plate thickness required for load combinations excluding thermal:	*0.42 inches*
Plate thickness provided:	*0.50 inches*
Maximum principal stress for load combinations 6 and 7 including thermal:	*67.3 ksi*
Yield stress at temperature:	*36.0 ksi*
Maximum stress intensity range for load combinations 6 and 7 including thermal:	*67.3 ksi*
Allowable stress intensity range for load combinations 6 and 7 including thermal:	*72.0 ksi*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.8.3-6 (Sheet 1 of 3)

*[DESIGN SUMMARY OF NORTH-EAST WALL OF IRWST
DESIGN LOADS, LOAD COMBINATIONS, AND COMPARISON TO ACCEPTANCE CRITERIA
MID-SPAN AT MID-HEIGHT]**

Load/Comb.	TX k/ft	TY k/ft	TXY k/ft	MX kft/ft	MY kft/ft	MXY kft/ft	NX k/ft	NY k/ft	Comments
Dead (D)	-1	-14	2	-1	-1	0	0	0	–
Hydro (F)	-4	-1	-3	20	22	3	0	-1	–
Live (L)	1	-12	0	-3	-2	0	0	-1	During refueling
Live (L_o)	0	-4	0	-1	0	0	0	0	During operation
Live (ADS)	-6	1	-4	21	21	4	0	1	–
E_s	16	22	49	19	24	6	1	3	–
Thermal (T_o)	-185	-84	90	348	356	1	-10	-12	–
LC (1)	-18	-25	-8	61	66	11	0	-1	$1.4D+1.4F+1.7L_o+1.7ADS$
LC (2)	-6	-42	0	22	27	3	0	-3	$1.4D+1.4F+1.7Lr$
LC (3)	-18	-19	-8	62	67	11	0	-1	$1.4D+1.4F+1.7ADS$
LC (4)	18	4	53	59	66	13	0	2	$D+F+L_o + \|ADS\|+E_s$
LC (5)	-27	-41	-53	-22	-22	-8	-1	-5	$D+F+L_o - \|ADS\|-E_s$
LC (6)	-168	-79	143	407	422	14	-9	-11	$D+F+L_o + \|ADS\|+T_o+E_s$
LC (7)	-213	-125	37	326	334	-7	-10	-17	$D+F+L_o - \|ADS\|+T_o-E_s$
LC (8)	5	9	43	59	66	13	1	2	$0.9D+1.0F+1.0ADS+1.0E_s$

Notes:
x-direction is horizontal, y-direction is vertical.
element number 40026

Plate thickness required for load combinations excluding thermal:	*0.10 inches*
Plate thickness provided:	*0.50 inches*
Maximum principal stress for load combinations 6 and 7 including thermal:	*37.6 ksi*
Yield stress at temperature:	*36.0 ksi*
Maximum stress intensity range for load combinations 6 and 7 including thermal:	*37.6 ksi*
Allowable stress intensity range for load combinations 6 and 7 including thermal:	*72.0 ksi*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.8.3-6 (Sheet 2 of 3)

[DESIGN SUMMARY OF NORTH-EAST WALL OF IRWST DESIGN LOADS, LOAD COMBINATIONS, AND COMPARISON TO ACCEPTANCE CRITERIA MID-SPAN AT BOTTOM – ELEVATION 107'-2"]*

Load/Comb.	*TX*	*TY*	*TXY*	*MX*	*MY*	*MXY*	*NX*	*NY*	*Comments*
	k/ft	*k/ft*	*k/ft*	*kft/ft*	*kft/ft*	*kft/ft*	*k/ft*	*k/ft*	
Dead (D)	-2	-18	3	0	3	1	0	0	–
Hydro (F)	-1	0	-5	2	-13	2	0	11	–
Live (L)	0	-10	1	0	3	0	0	-1	*During refueling*
Live (L_o)	0	-3	0	0	2	0	0	0	*During operation*
Live (ADS)	-1	2	-6	1	-13	2	1	8	–
E_s	16	31	58	4	37	3	1	10	–
Thermal (T_o)	-382	-35	184	419	479	11	3	-18	–
LC (1)	-5	-26	-12	6	-34	8	2	29	$1.4D+1.4F+1.7L_o+1.7ADS$
LC (2)	-5	-41	-2	4	-9	4	0	14	$1.4D+1.4F+1.7Lr$
LC (3)	-5	-21	-12	5	-37	7	2	2	$1.4D+1.4F+1.7ADS$
LC (4)	14	13	63	8	41	8	2	29	$D+F+L_o + \|ADS\|+E_s$
LC (5)	-20	-53	-66	-3	-59	-3	-1	-7	$D+F+L_o - \|ADS\|-E_s$
LC (6)	-368	-22	247	427	520	20	5	11	$D+F+L_o + \|ADS\|+T_o+E_s$
LC (7)	-401	-88	119	416	420	9	2	-25	$D+F+L_o - \|ADS\|+T_o-E_s$
LC (8)	12	17	51	8	13	8	2	29	$0.9D+1.0F+1.0ADS+1.0E_s$

Notes:
x-direction is horizontal, y-direction is vertical.
element number 40006

Plate thickness required for load combinations excluding thermal:	*0.09 inches*
Plate thickness provided:	*0.50 inches*
Maximum principal stress for load combinations 6 and 7 including thermal:	*50.0 ksi*
Yield stress at temperature:	*36.0 ksi*
Maximum stress intensity range for load combinations 6 and 7 including thermal:	*50.0 ksi*
Allowable stress intensity range for load combinations 6 and 7 including thermal:	*72.0 ksi*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.8.3-6 (Sheet 3 of 3)

[*DESIGN SUMMARY OF NORTH-EAST WALL OF IRWST*
DESIGN LOADS, LOAD COMBINATIONS, AND COMPARISON TO ACCEPTANCE CRITERIA
NORTH END BOTTOM CORNER – ELEVATION 107'-2"]*

Load/Comb.	TX k/ft	TY k/ft	TXY k/ft	MX kft/ft	MY kft/ft	MXY kft/ft	NX k/ft	NY k/ft	Comments
Dead (D)	0	-13	3	0	0	0	0	0	–
Hydro (F)	-1	17	6	10	17	14	-6	-14	–
Live (L)	0	-9	2	0	1	0	0	0	During refueling
Live (L_o)	0	-2	1	0	0	0	0	0	During operation
Live (ADS)	-1	27	7	12	24	14	-6	-17	–
E_s	5	57	41	15	41	12	7	17	–
Thermal (T_o)	-99	155	256	173	394	-65	24	70	–
LC (1)	-4	49	26	34	65	43	-18	-47	$1.4D+1.4F+1.7L_o+1.7ADS$
LC (2)	-2	-10	17	13	26	19	-9	-19	$1.4D+1.4F+1.7Lr$
LC (3)	-4	53	25	34	65	44	-18	-48	$1.4D+1.4F+1.7ADS$
LC (4)	5	86	58	37	83	40	7	20	$D+F+L_o + \|ADS\|+E_s$
LC (5)	-8	-82	-38	-18	-47	-12	-19	-48	$D+F+L_o - \|ADS\|-E_s$
LC (6)	-94	241	314	209	477	-25	30	90	$D+F+L_o + \|ADS\|+T_o+E_s$
LC (7)	-107	73	218	155	347	-77	4	22	$D+F+L_o - \|ADS\|+T_o-E_s$
LC (8)	2	90	57	37	82	40	-5	-13	$0.9D+1.0F+1.0ADS+1.0E_s$

Notes:
x-direction is horizontal, y-direction is vertical.
element number 40001

Plate thickness required for load combinations excluding thermal:	*0.24 inches*
Plate thickness provided:	*0.50 inches*
Maximum principal stress for load combinations 6 and 7 including thermal:	*58.7 ksi*
Yield stress at temperature:	*36.0 ksi*
Maximum stress intensity range for load combinations 6 and 7 including thermal:	*61.6 ksi*
Allowable stress intensity range for load combinations 6 and 7 including thermal:	*72.0 ksi*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.8.3-7

DESIGN SUMMARY OF STEEL WALL OF IRWST

Mechanical Loads Only AISC Interaction Ratio			
Section Location and Element Number	**T Section**	**L Section**	**Load Combination**
TYPICAL COLUMN AT MIDDLE OF WALL			
Top (39701)	0.012	0.407	D + F + L_o + ADS (LC # 1)
	0.067	0.212	D + F + L_o + ADS + E_s (LC # 5)
Mid-height (39696)	0.105	0.337	D + F + L_o + ADS (LC # 1)
	0.082	0.111	D + F + L_o + ADS + E_s (LC # 5)
Bottom (39690)	0.387	0.064	D + F + L_o + ADS (LC # 1)
	0.330	0.067	D + F + L_o + ADS + E_s (LC # 5)
ENVELOPE OF ALL LOCATIONS AND LOAD COMBINATIONS			
	0.563	0.775	LC # 1 to 5 and 8

Mechanical Plus Thermal Loads Ratio of Stress to AISC or ASME (2 * Sy = 80 ksi)				
Section Location and Element Number	**Flange of T Section**	**Flange of L Section**	**Plate**	**Load Combination**
TYPICAL COLUMN AT MIDDLE OF WALL				
Top (39701)	0.103 AISC	0.314 AISC	–	D+F+L_o+ADS+E_s+T (LC # 7)
Mid-height (39696)	0.303 AISC	0.968 AISC	–	D+F+L_o+ADS+E_s+T (LC # 7)
Bottom (39690)	0.46 ASME	0.36 ASME	0.78	D+F+L_o+ADS+E_s+T (LC # 7)
ENVELOPE OF ALL LOCATIONS AND LOAD COMBINATIONS				
–	0.72 ASME	0.73 ASME	0.89	LC # 6, 7 and 9

Note:
Results of the evaluation of mechanical and thermal loads are shown against the AISC allowables when the stresses are less than yield. Portions of the steel wall at the end of the wall exceed yield due to the restraint provided by the adjacent concrete. These areas are evaluated against the ASME allowables as described in subsection 3.8.3.5.3.4.

Table 3.8.4-1

[*LOAD COMBINATIONS AND LOAD FACTORS FOR SEISMIC CATEGORY I STEEL STRUCTURES*]*

Combination No.		*Load Combination and Factors*								
		1	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***
Load Description										
Dead	D	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Liquid	F	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Live	L	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Earth pressure	H	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Normal reaction	R_o	1.0	1.0	1.0	1.0				1.0	1.0
Normal thermal	T_o			1.0	1.0				1.0	1.0
Wind	W		1.0							1.0
Safe shutdown earthquake	E_S			1.0				1.0		
Tornado	W_t				1.0					
Accident pressure	P_a					1.0	1.0	1.0		
Accident thermal	T_a					1.0	1.0	1.0		
Accident thermal reactions	R_a					1.0	1.0	1.0		
Accident pipe reactions	Y_r						1.0	1.0		
Jet impingement	Y_j						1.0	1.0		
Pipe impact	Y_m						1.0	1.0		
Stress Limit Coefficient [(1),(3)] *(except for compression)*		1.0	1.0	1.6	1.6	1.6	1.6	1.7	1.5	1.5
(for compression)		1.0	1.0	1.4	1.4	1.4	1.4	1.6	1.3	1.3

Notes:

1. *Allowable stress limits coefficients are applied to the basic stress allowables of AISI or AISC. The coefficients for AISC-N690 are supplemented by the requirements identified in subsection 3.8.4.5.*
2. *Where any load reduces the effects of other loads, the coefficient for that load is taken as zero unless it can be demonstrated that the load is always present or occurs simultaneously with the other loads.*
3. *In no instance does the allowable stress exceed $0.7F_u$ in axial tension nor $0.7F_u$ times the ratio of the plastic to elastic section modulus for tension plus bending.*
4. *Loads due to maximum precipitation are evaluated using load combination 4 with the maximum precipitation in place of the tornado load.*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.8.4-2

*[LOAD COMBINATIONS AND LOAD FACTORS FOR SEISMIC CATEGORY I CONCRETE STRUCTURES]**

Combination No.		***Load Combination and Factors***								
		1	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***
Load Description										
Dead	D	*1.4*	*1.4*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.05*	*1.05*
Liquid	F	*1.4*	*1.4*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.05*	*1.05*
Live	L	*1.7*	*1.7*	*1.0*	*1.0*	*1.0*	*1.0*	*1.0*	*1.3*	*1.3*
Earth	H	*1.7*	*1.7*	*1.0*	*1.0*	*1.0*		*1.0*	*1.3*	*1.3*
Normal reaction	R_o	*1.7*	*1.7*	*1.0*	*1.0*				*1.3*	*1.3*
Normal thermal	T_o			*1.0*	*1.0*				*1.2*	*1.2*
Wind	W		*1.7*							*1.3*
Safe shutdown earthquake	E_s			*1.0*				*1.0*		
Tornado	W_t				*1.0*					
Accident pressure	P_a					*1.4*	*1.25*	*1.0*		
Accident thermal	T_a					*1.0*	*1.0*	*1.0*		
Accident thermal reactions	R_a					*1.0*	*1.0*	*1.0*		
Accident pipe reactions	Y_r						*1.0*	*1.0*		
Jet impingement	Y_j						*1.0*	*1.0*		
Pipe impact	Y_m						*1.0*	*1.0*		

Notes:

1. *Design for mechanical loads is in accordance with ACI-349 Strength Design Method for all load combinations. Design for combinations including thermal loads is described in subsection 3.8.3.5.3.4.*
2. *Where any load reduces the effects of other loads, the corresponding coefficient for that load is taken as 0.9 if it can be demonstrated that the load is always present or occurs simultaneously with the other loads. Otherwise the coefficient for the load is taken as zero.*
3. *Loads due to maximum precipitation are evaluated using load combination 4 with the maximum precipitation in place of the tornado load.*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.8.4-3

ACCEPTANCE TESTS FOR CONCRETE AGGREGATES

Method of Test	Designation
Organic impurities in sand	ASTM C 40
Effect of organic impurities on strength of mortar	ASTM C 87
Soundness of aggregates	ASTM C 88
Material finer than No. 200 sieve	ASTM C 117
Specific gravity and absorption - coarse aggregates	ASTM C 127
Specific gravity and absorption - fine aggregates	ASTM C 128
Los Angeles abrasion of small-size coarse aggregates	ASTM C 131
Sieve analysis	ASTM C 136
Friable particles	ASTM C 142
Potential reactivity of aggregates (chemical)	ASTM C 289
Petrographic examination of aggregates	ASTM C 295
Resistance to degradation of large-size coarse aggregates by abrasion and impact in the Los Angeles machine	ASTM C 535
Potential alkali reactivity of carbonate rocks for concrete aggregates	ASTM C 586
Resistance of concrete to rapid freezing and thawing	ASTM C 666
Flat and elongated particles	CRD C 119

Table 3.8.4-4

CRITERIA FOR WATER USED IN PRODUCTION OF CONCRETE

Requirements and Test Method	Criteria
Compressive strength ASTM C 109	Reduction in strength not in excess of 10 percent
Soundness ASTM C 151	Increase in length limited to 0.10 percent
Time of setting ASTM C 191	± 10 min for initial set, ± 1 hour for final set

Table 3.8.4-5

TYPES OF WATER REDUCING AGENTS USED IN PRODUCTION OF CONCRETE

Concrete Placing Temperature	Placement Description	WRA[1] Type
70°F or less	For normal conditions	A
70°F or less	For additional retardation for members with least dimension of 3.0 feet or more	D
More than 70°F	For members except floor slabs	D
More than 70°F	For floor slabs	A

Note:
1. Water reducing agent

Table 3.8.4-6

MATERIALS USED IN STRUCTURAL AND MISCELLANEOUS STEEL

Standard	Construction Material
ASTM A1	Carbon steel rails
ASTM A36/A36M	Rolled shapes, plates, and bars
ASTM A108	Weld studs
ASTM A123	Zinc coatings (hot galvanized)
ASTM A240	Nitronic 33 stainless steel (designation S2400, Type XM-29)
ASTM A307	Low carbon steel bolts
ASTM A325	High strength bolts
ASTM A354	Quenched and tempered alloy steel bolts (Grade BC)
ASTM A588	High-strength low alloy structural steel
ASTM-F1554	Steel anchor bolts, 36, 55, and 105-ksi Yield Strength

Table 3.8.5-1

MINIMUM REQUIRED FACTOR OF SAFETY FOR OVERTURNING AND SLIDING OF STRUCTURES

Load Combination	Overturning	Sliding	Flotation
D + H + B + W	1.5	1.5	-
D + H + B + E_s	1.1	1.1	-
D + H + B + W_t	1.1	1.1	-
D + F	-	-	1.1
D + B	-	-	1.5

where:

D = dead load excluding the fluid loads

H = lateral earth pressure

W = wind load

E_s = safe shutdown earthquake load

W_t = tornado load

F = buoyant force due to the design basis flood

B = buoyant force on submerged structure due to high ground water table

Table 3.8.5-2

FACTORS OF SAFETY FOR FLOTATION, OVERTURNING AND SLIDING OF NUCLEAR ISLAND STRUCTURES

HARD ROCK CONDITION

Environmental Effect	Factor of Safety(1)
Flotation	
High Ground Water Table	3.7
Design Basis Flood	3.5
Sliding	
Design Wind, North-South	18.4
Design Wind, East-West	14.0
Design Basis Tornado, North-South	10.3
Design Basis Tornado, East-West	8.6
Safe Shutdown Earthquake, North-South	1.25
Safe Shutdown Earthquake, East-West	1.5
Overturning	
Design Wind, North-South	51.7
Design Wind, East-West	28.0
Design Basis Tornado, North-South	17.7
Design Basis Tornado, East-West	9.6
Safe Shutdown Earthquake, North-South	1.75
Safe Shutdown Earthquake, East-West	1.2

Note:
1. Factor of safety is calculated for a site with rock below the underside of the base mat (elevation 60′-6″) and soil adjacent to the exterior walls above this elevation.

Table 3.8.5-3

[*DEFINITION OF CRITICAL LOCATIONS AND THICKNESSES FOR NUCLEAR ISLAND BASEMAT*[(1)]]*

Wall or Section Description	***Applicable Column Lines***	***Applicable Elevation Level or Elevation Level Range***	***Concrete Thickness***[(2)]	***Reinforcement Required Vertical*** ***(in^2/ft^2)***[(3)]	***Reinforcement Required Horizontal*** ***(in^2/ft)***[(3)]	***Reinforcement Provided Vertical*** ***(in^2/ft^2)***[(4)]	***Reinforcement Provided Horizontal*** ***(in^2/ft)***[(4)]
Auxiliary Building Basemat							
Auxiliary Basemat Area	*Column line K to L and from Col. Line 11 wall to the intersection with the shield building*	*From level 0 to 1*	*6'-0"*	***Shear Reinforcement*** *0.29*	***Bottom Reinforcement*** *1.6 (East-West Direction)* ***Top Reinforcement*** *1.6 (East-West Direction)*	***Shear Reinforcement*** *0.30*	***Bottom Reinforcement*** *2.7 (East-West Direction)* ***Top Reinforcement*** *2.7 (East-West Direction)*
Auxiliary Basemat Area	*Column line 1 to 2 and from Column Line K-2 to N wall*	*From level 0 to 1*	*6'-0"*	***Shear Reinforcement*** *0.49*	***Bottom Reinforcement at column line 2*** *2.8 (North-South Direction)* ***Top Reinforcement at mid-span*** *2.9 (North-South Direction)*	***Shear Reinforcement*** *0.78*	***Bottom Reinforcement*** *4.5 (North-South Direction)* ***Top Reinforcement*** *3.12 (North-South Direction)*

Notes:

1. *The applicable column lines and elevation levels are identified and included in Figures 1.2-9, 3.7.2-12 (sheets 1 through 12), 3.7.2-19 (sheets 1 through 3) and on Table 1.2-1.*
2. *These thicknesses have a construction tolerance of +1 inch, -3/4 inch.*
3. *These concrete reinforcement values represent the minimum reinforcement required for structural requirements except for designed openings, penetrations, sumps or elevator pits.*
4. *These concrete reinforcement values represent the provided reinforcement for structural requirements except for designed openings, penetrations, sumps or elevator pits.*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

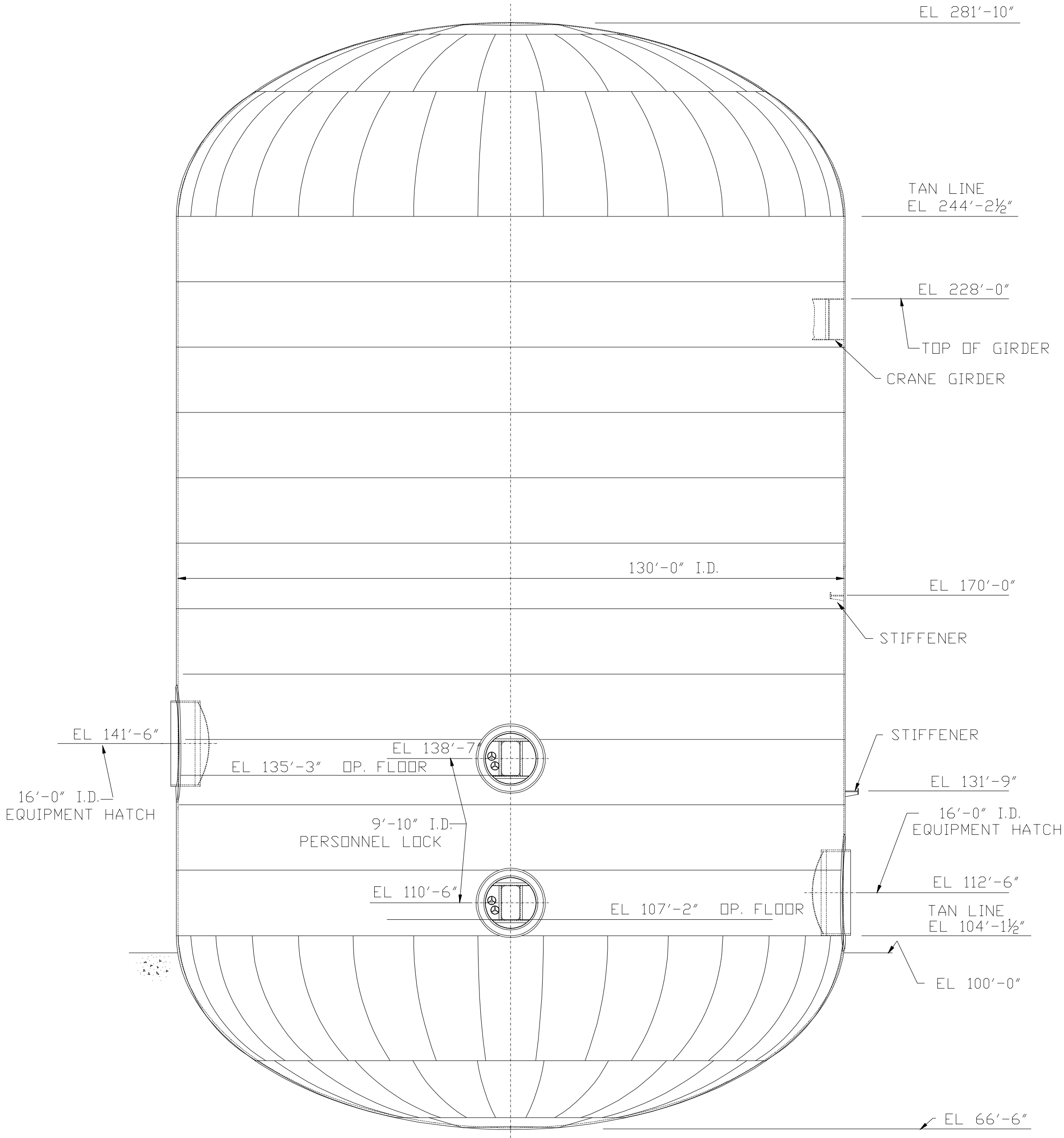


Figure 3.8.2-1 (Sheet 1 of 3)

Containment Vessel General Outline

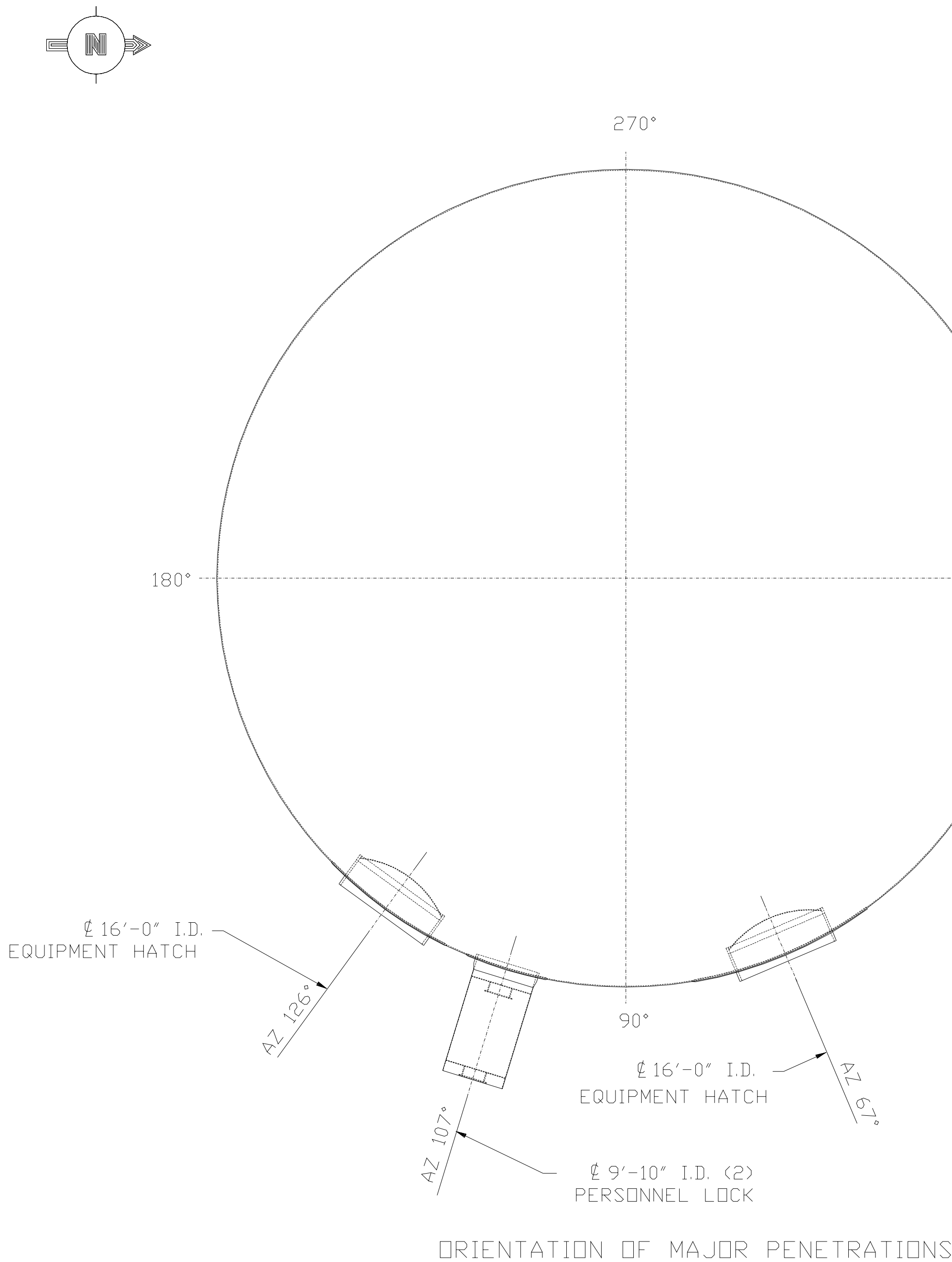


Figure 3.8.2-1 (Sheet 2 of 3)

Containment Vessel General Outline

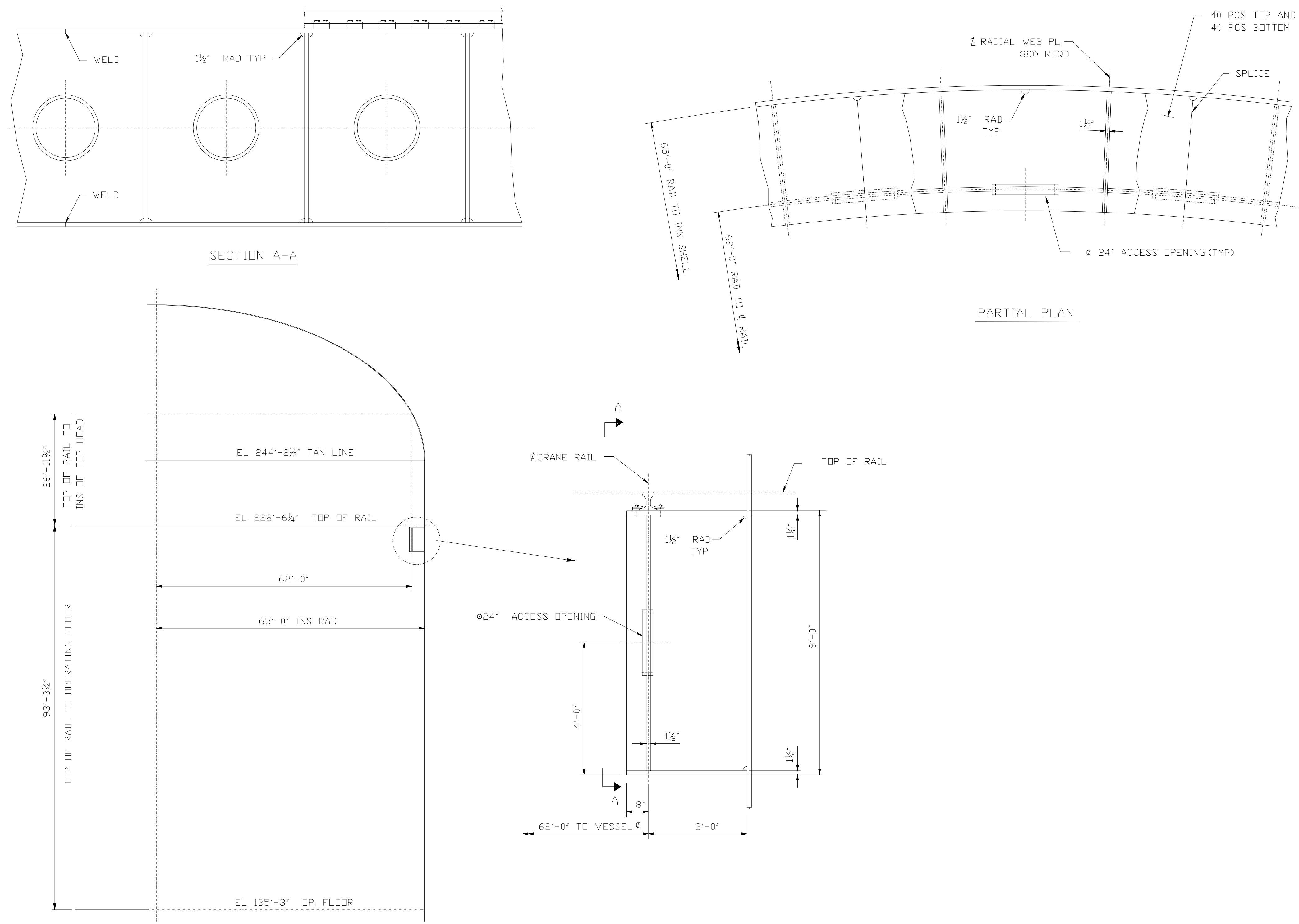


Figure 3.8.2-1 (Sheet 3 of 3)

Containment Vessel General Outline

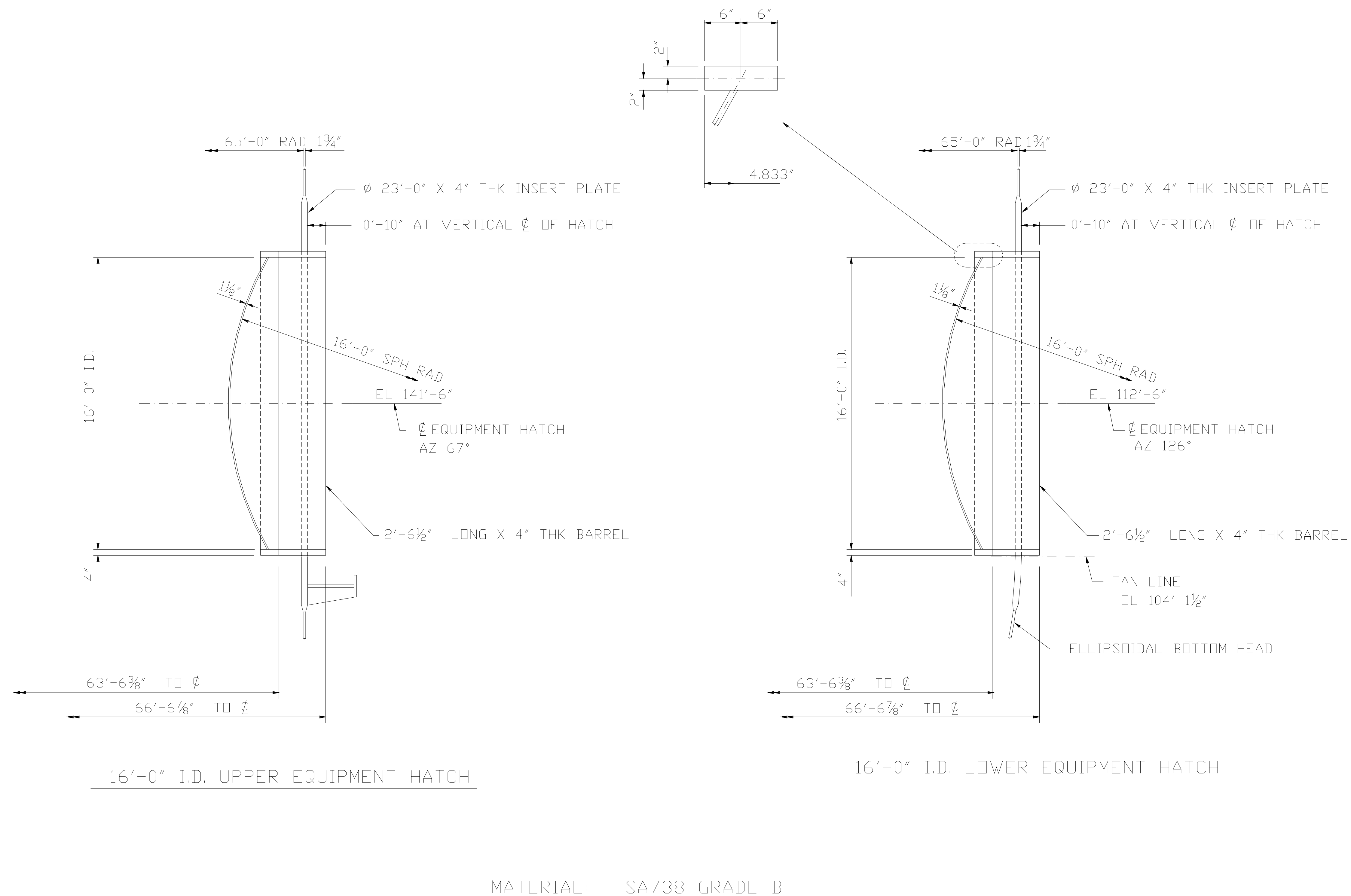


Figure 3.8.2-2

Equipment Hatches

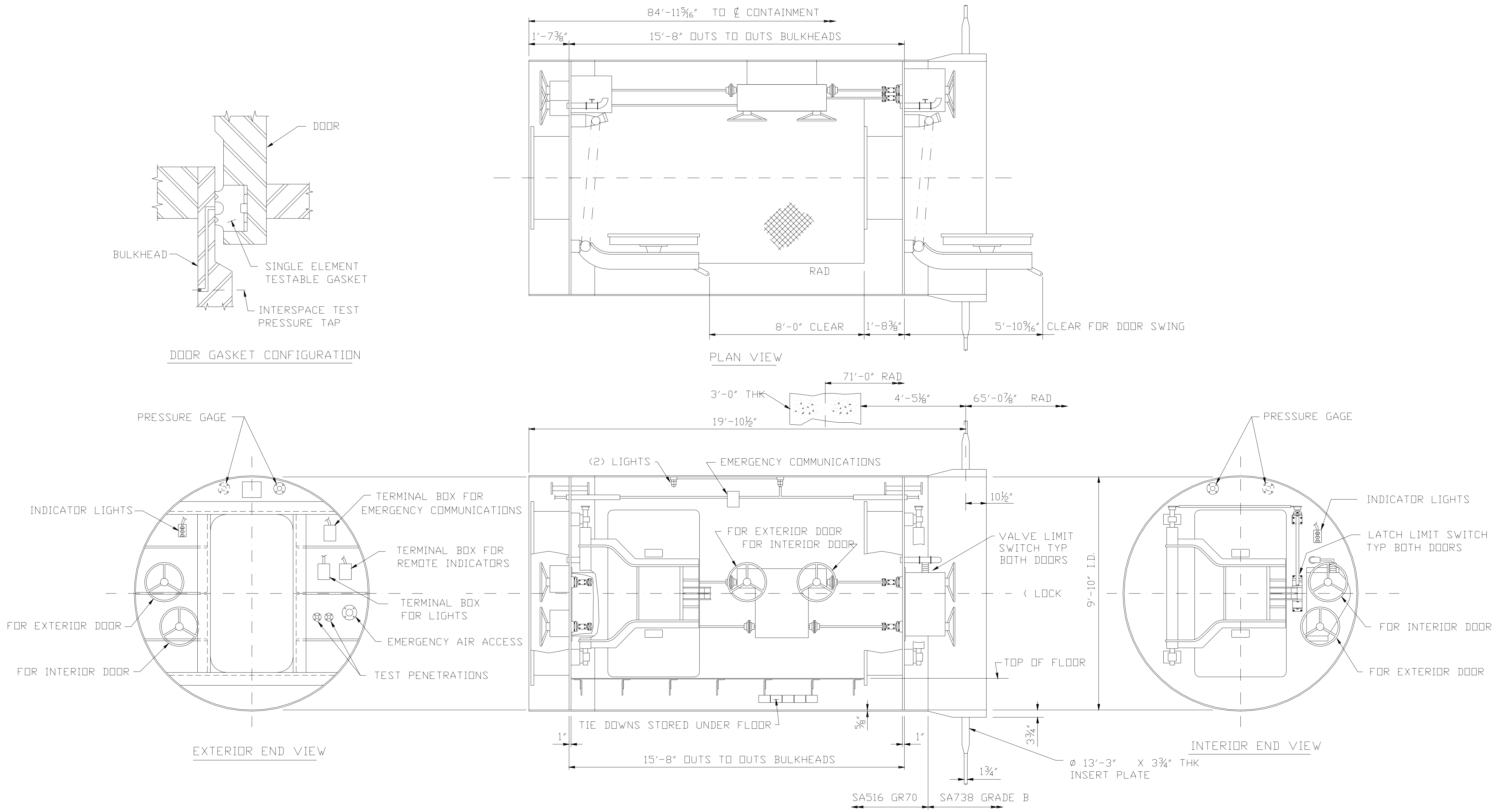


Figure 3.8.2-3

Personnel Airlock

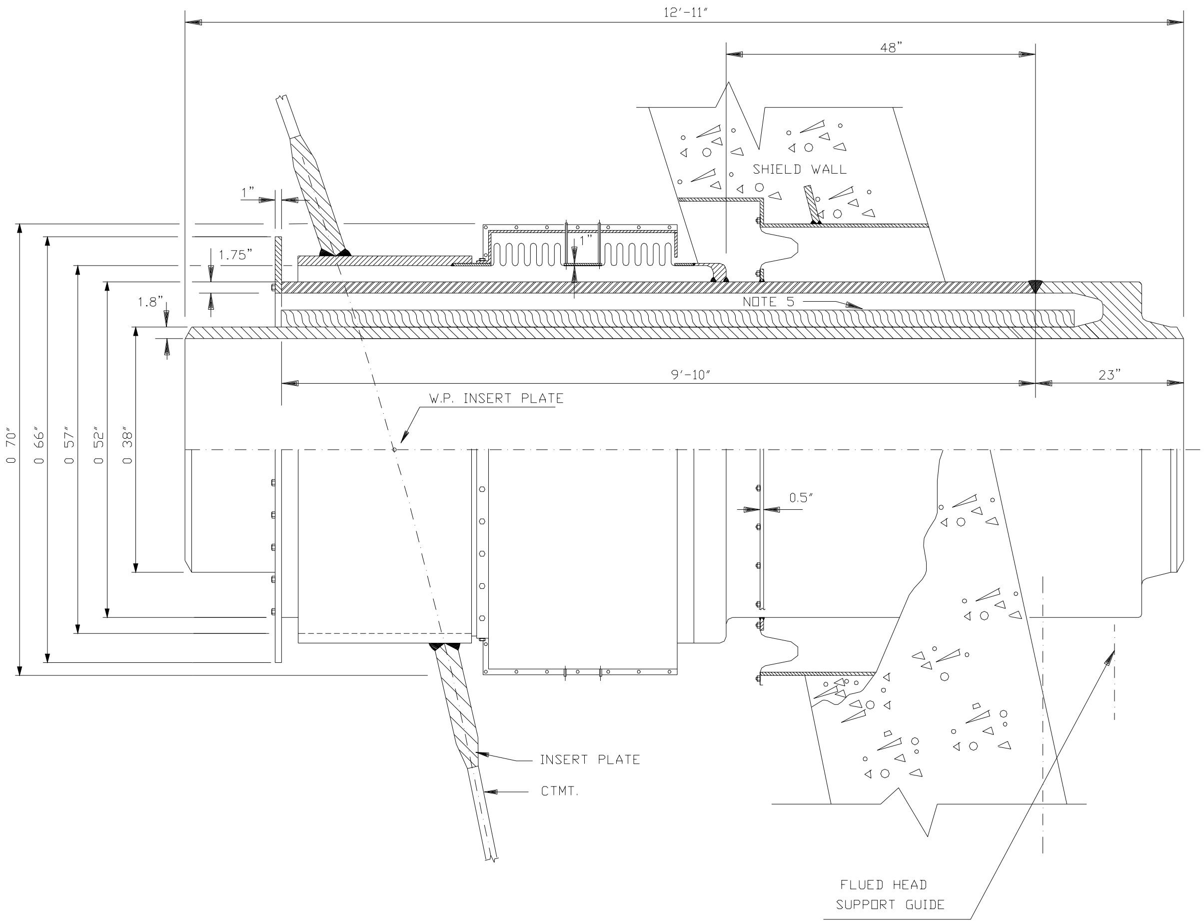


Figure 3.8.2-4 (Sheet 1 of 6)

Containment Penetrations Main Steam

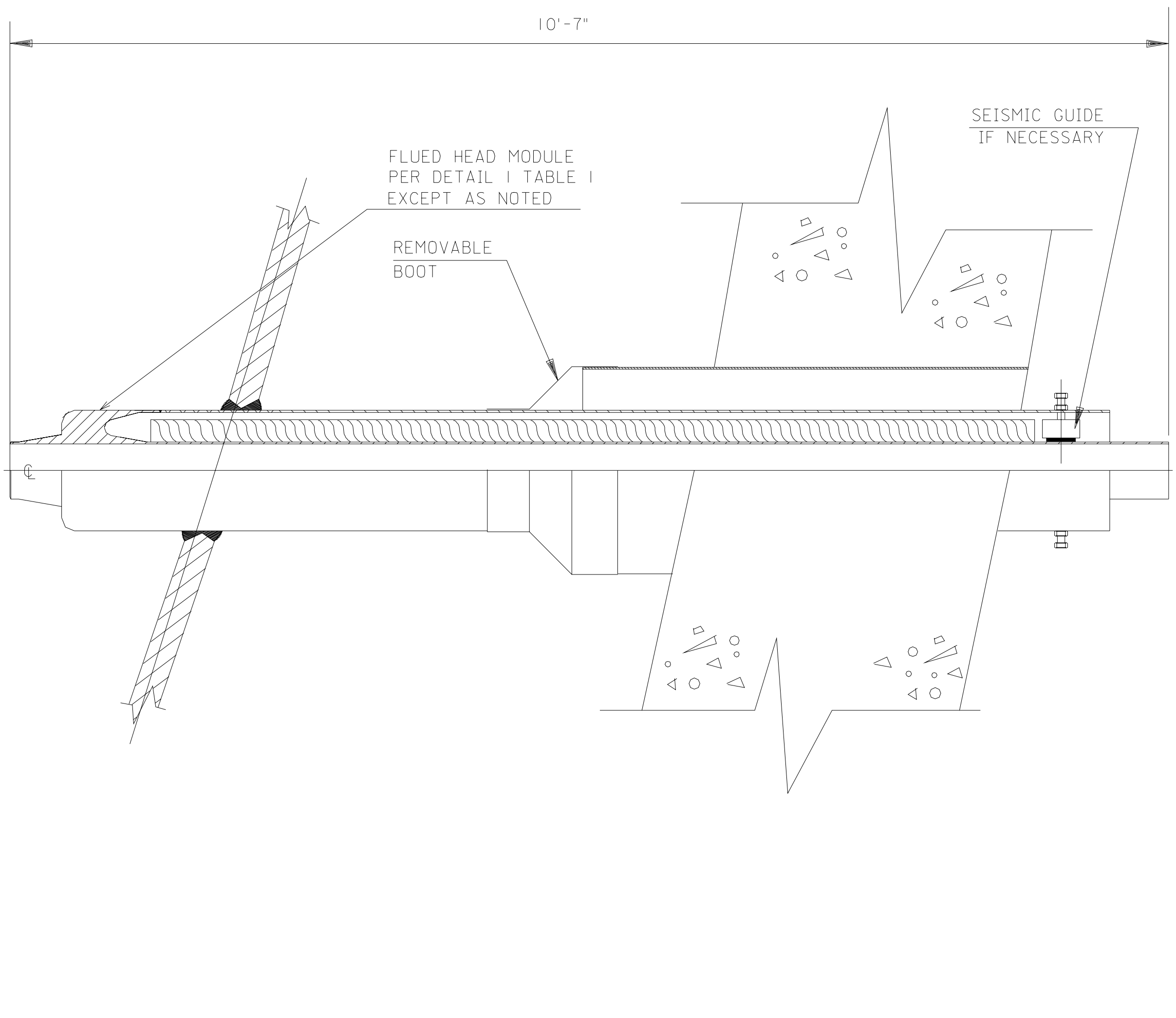


Figure 3.8.2-4 (Sheet 2 of 6)

Containment Penetrations Startup Feedwater

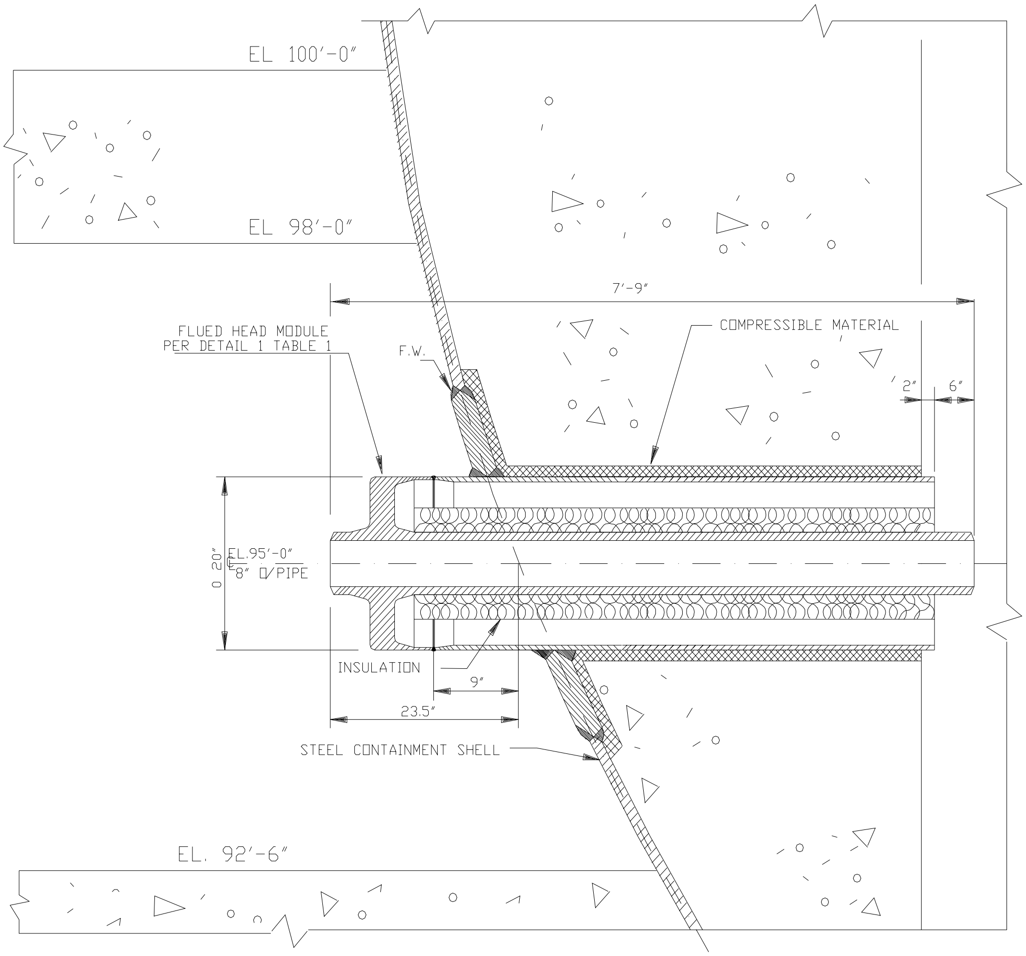
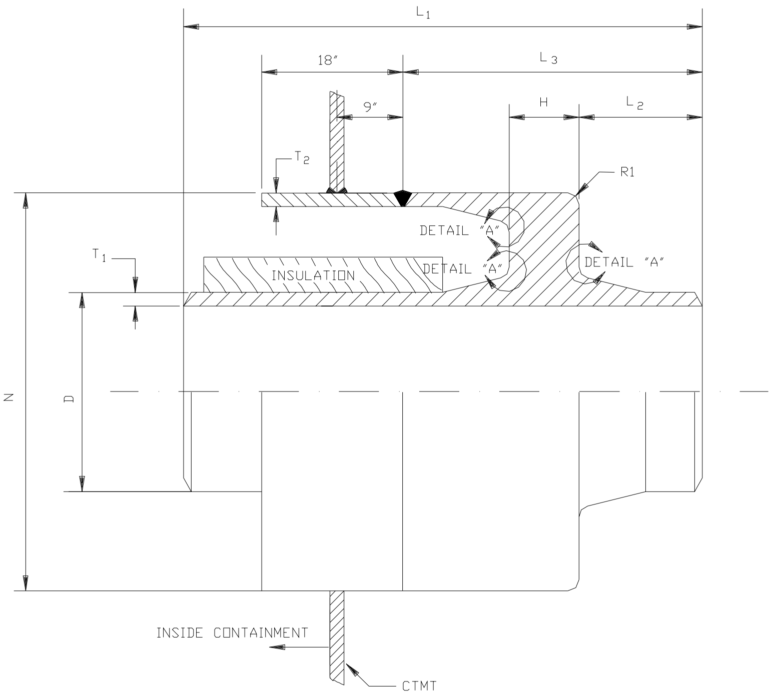


Figure 3.8.2-4 (Sheet 3 of 6)

Containment Penetrations Normal RHR Piping



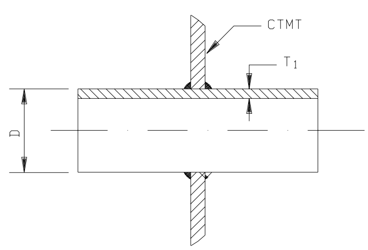


Figure 3.8.2-4 (Sheet 4 of 6)

Containment Penetrations

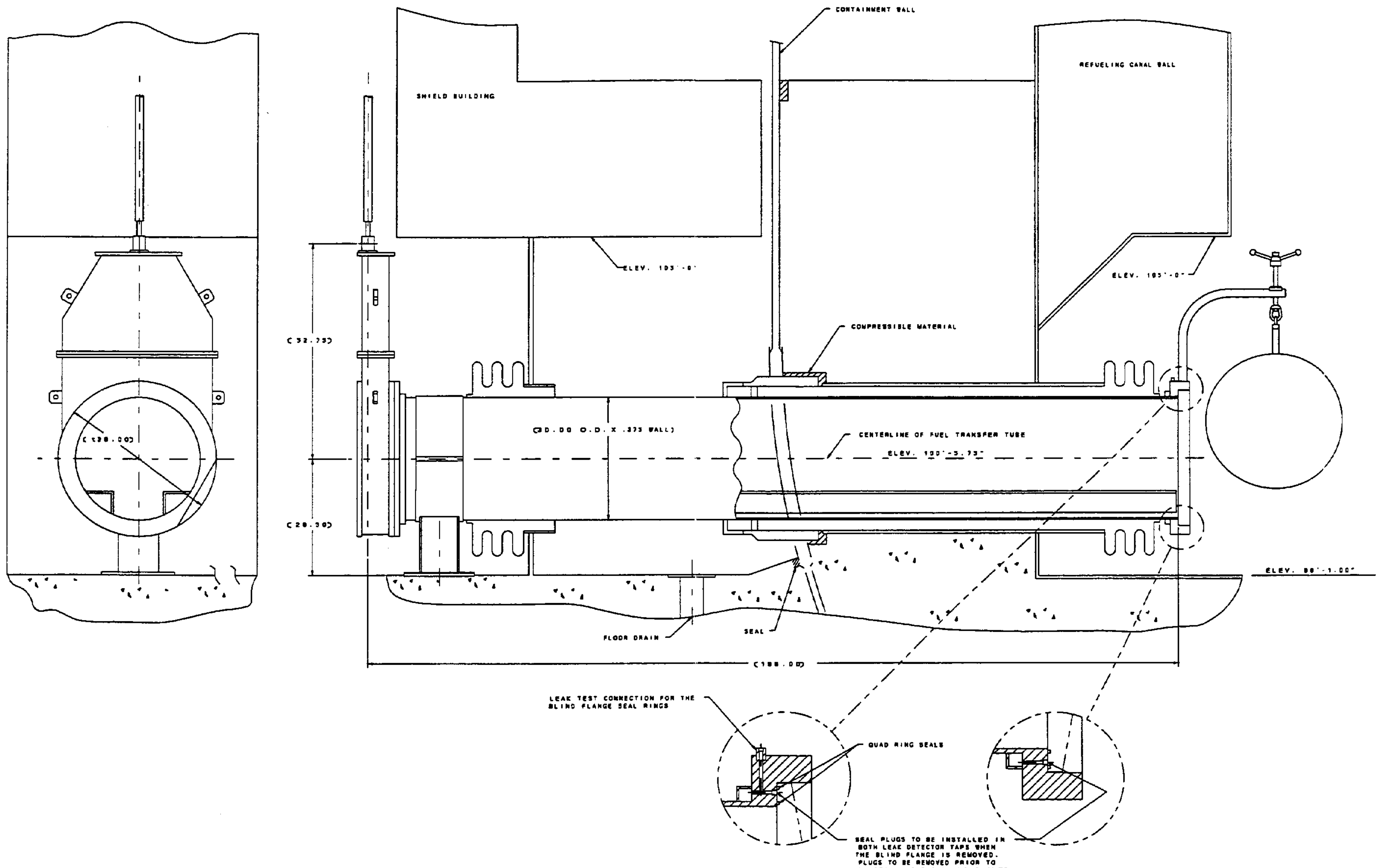


Figure 3.8.2-4 (Sheet 5 of 6)

Containment Penetrations
Fuel Transfer Penetration

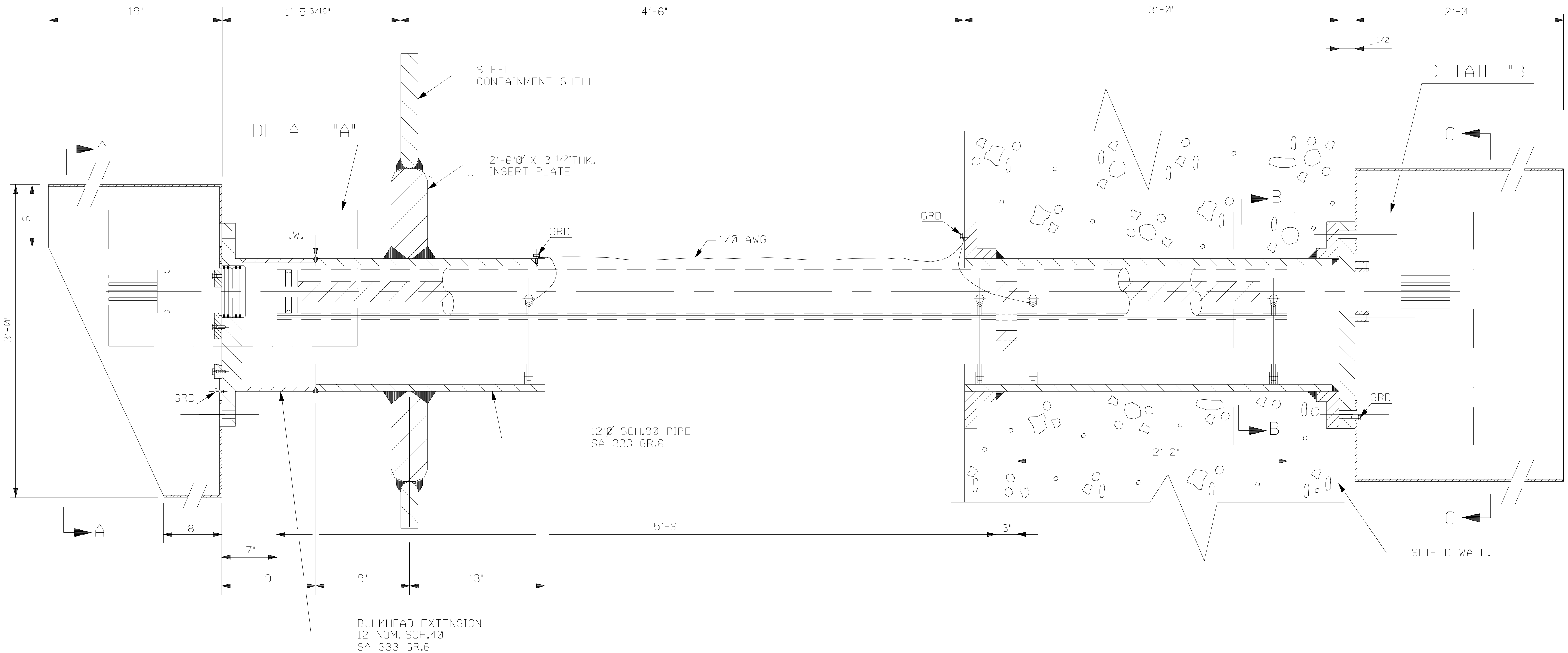


Figure 3.8.2-4 (Sheet 6 of 6)

Containment Penetrations
Typical Electrical Penetration

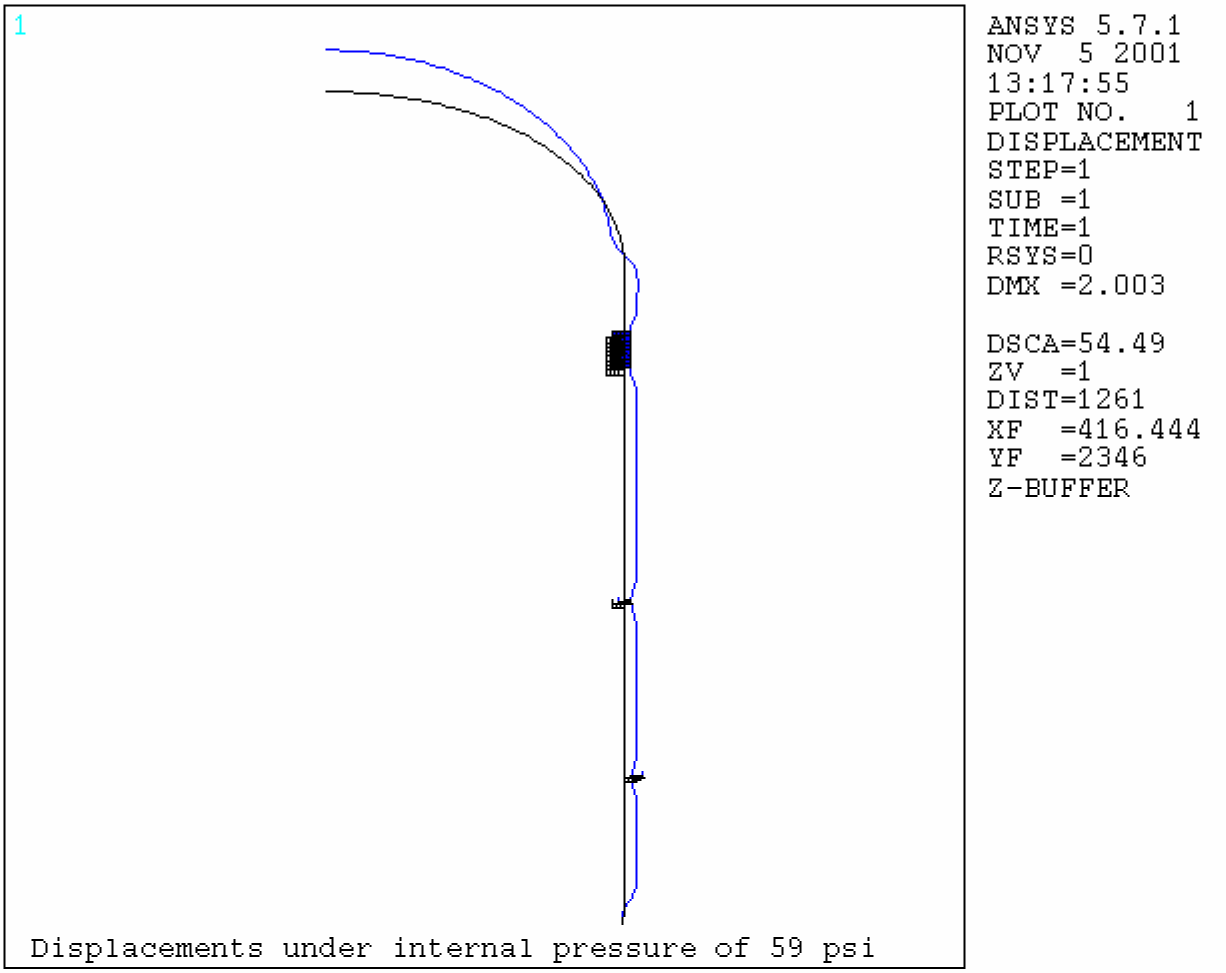
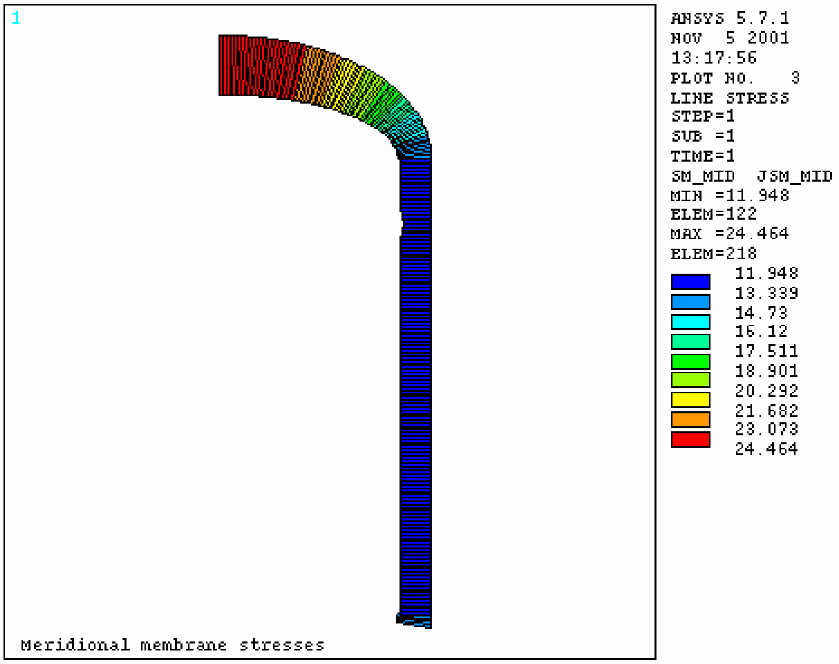
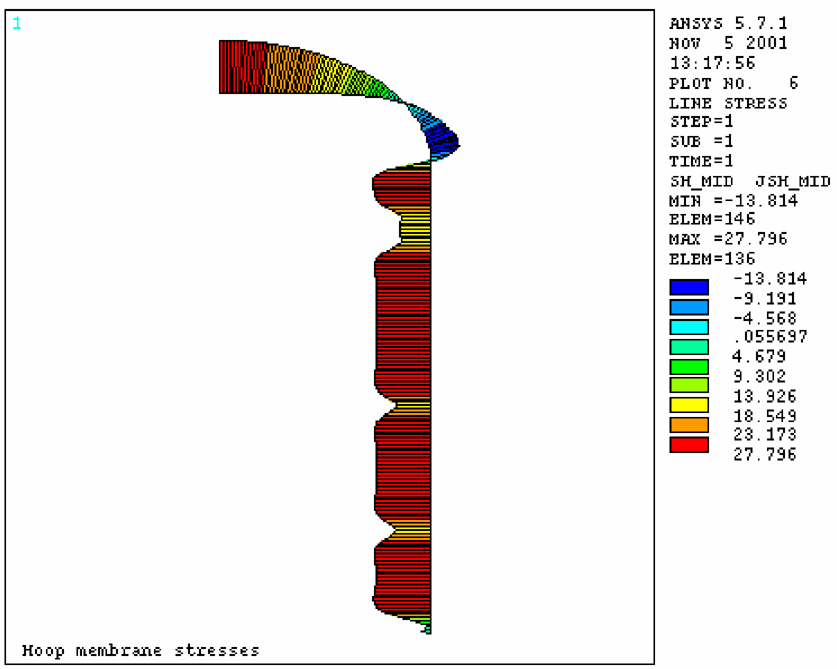


Figure 3.8.2-5 (Sheet 1 of 5)

**Containment Vessel Response to Internal Pressure of 59 psig
Displaced Shape Plot**



Meridional Membrane Stress (ksi)



Circumferential Membrane Stress (ksi)

Figure 3.8.2-5 (Sheet 2 of 5)

Containment Vessel Response to Internal Pressure of 59 psig Membrane Stresses (ksi)

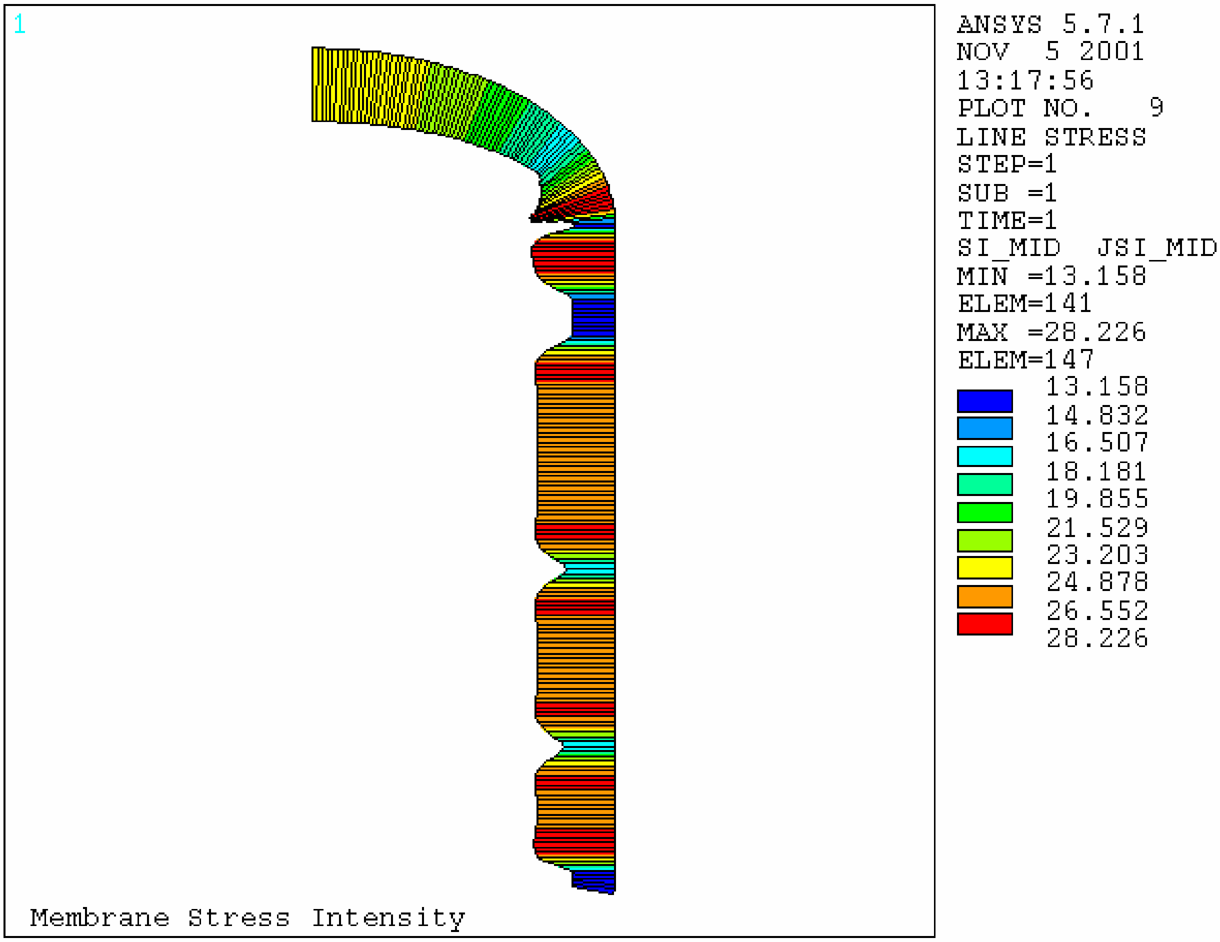
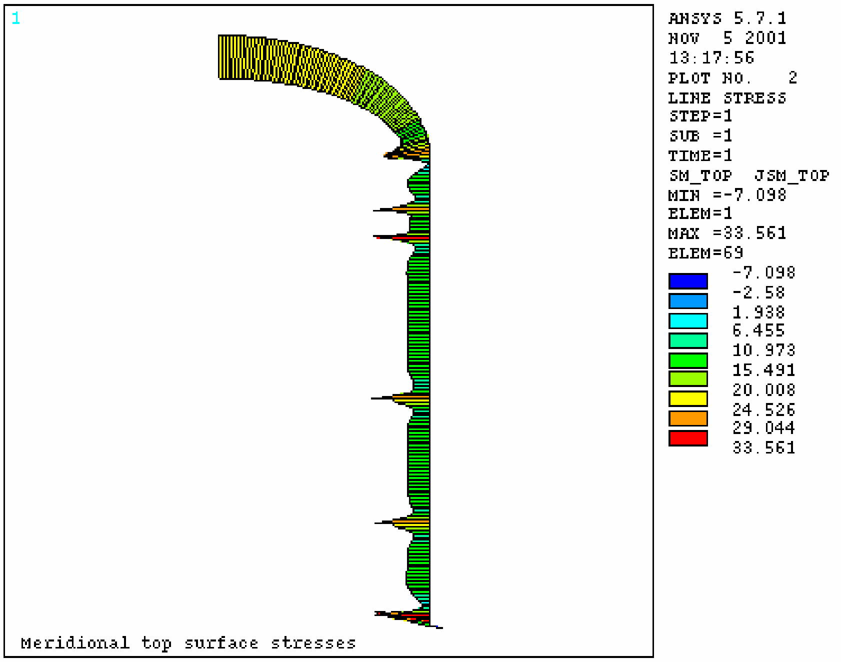
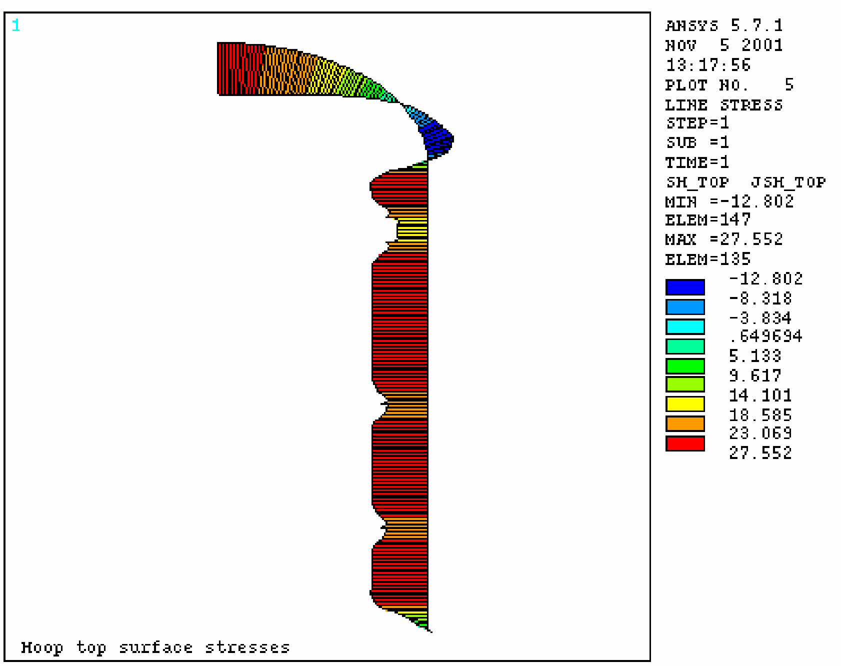


Figure 3.8.2-5 (Sheet 3 of 5)

Containment Vessel Response to Internal Pressure of 59 psig
Surface Meridional Stress (ksi)



Meridional Top Surface Stress (ksi)



Circumferential Top Surface Stress (ksi)

Figure 3.8.2-5 (Sheet 4 of 5)

**Containment Vessel Response to Internal Pressure of 59 psig
Outside Surface Stresses (ksi)**

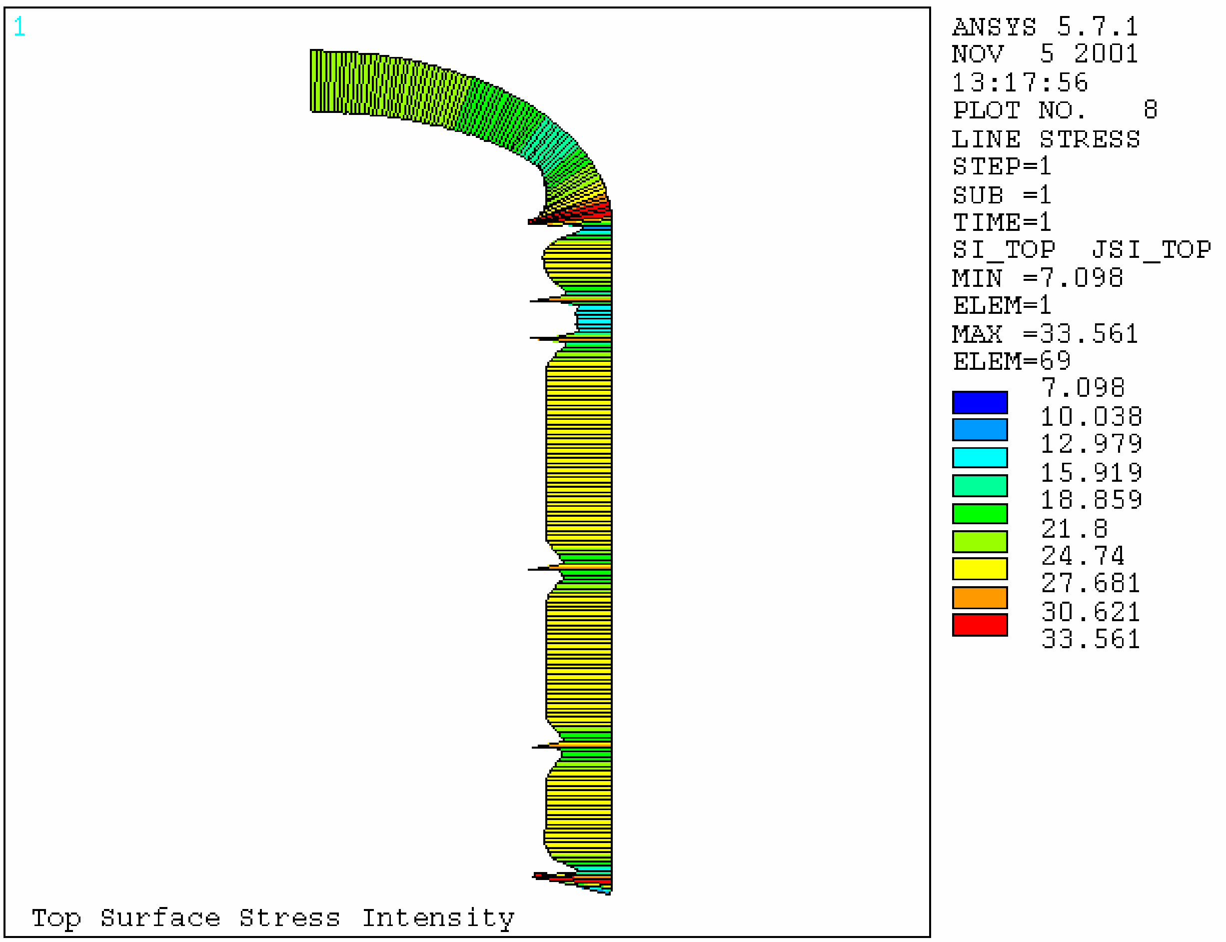


Figure 3.8.2-5 (Sheet 5 of 5)

**Containment Vessel Response to Internal Pressure of 59 psig
Outer Stress Intensity (ksi)**

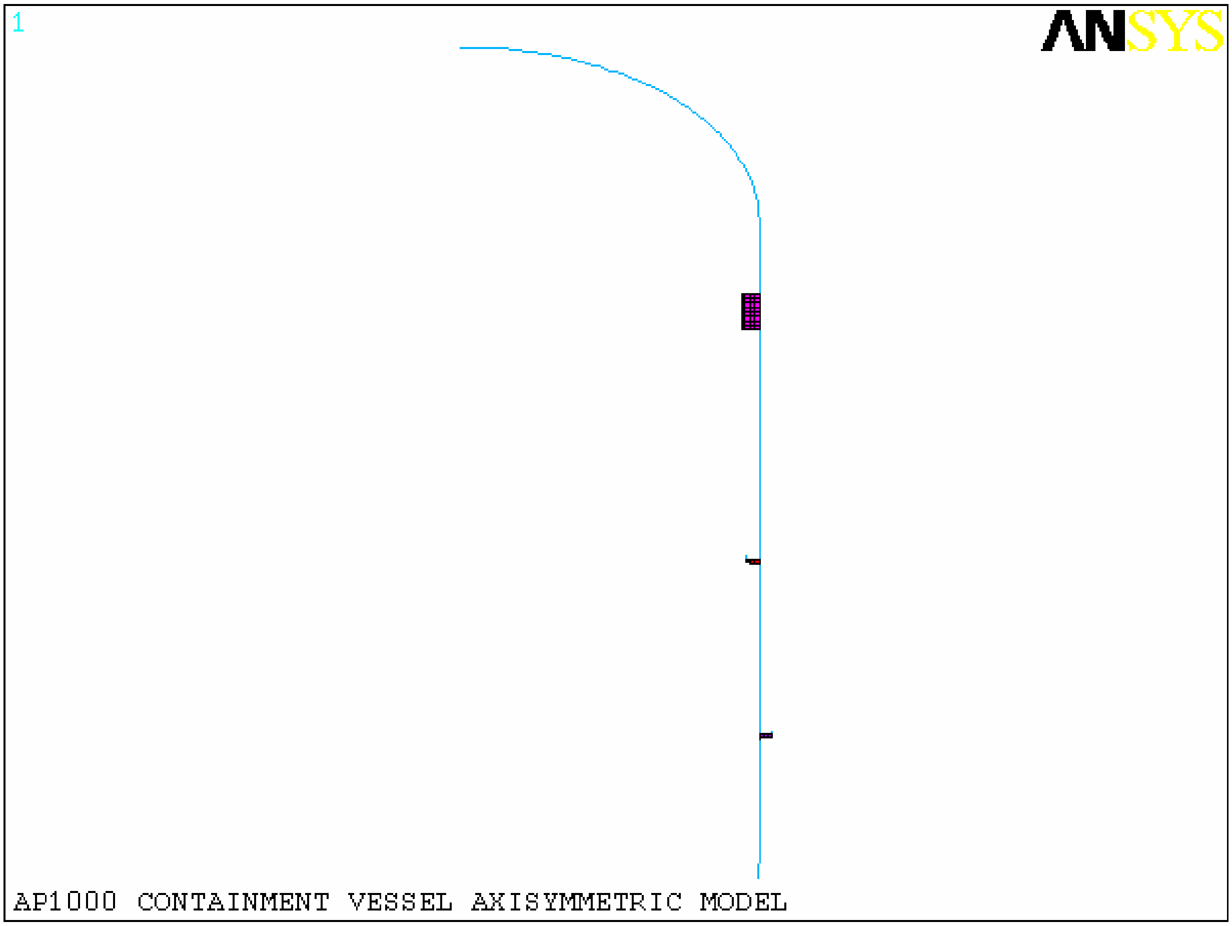
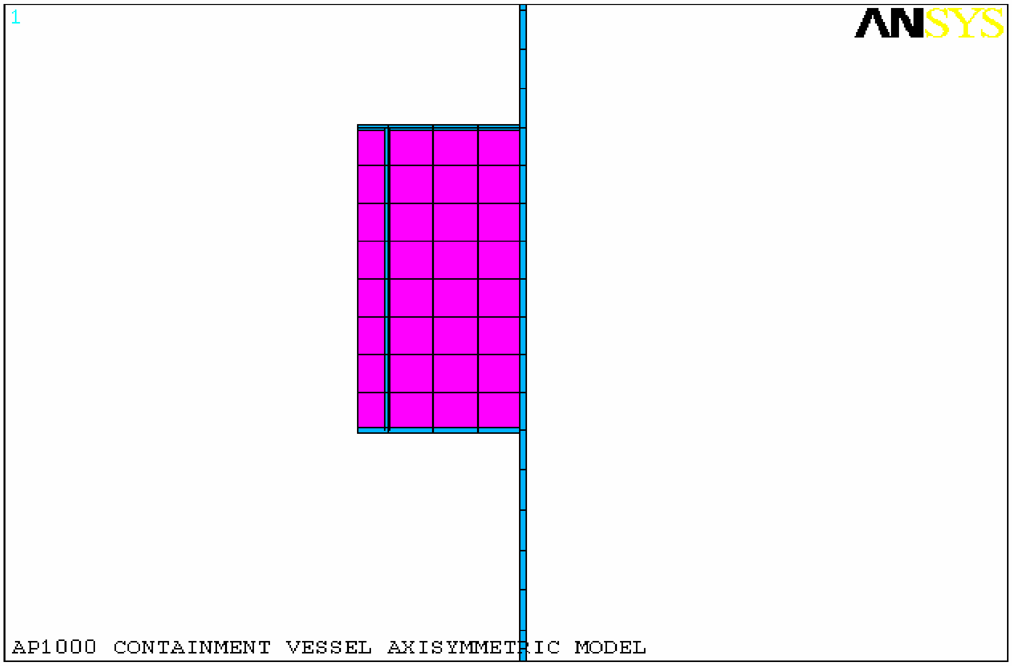
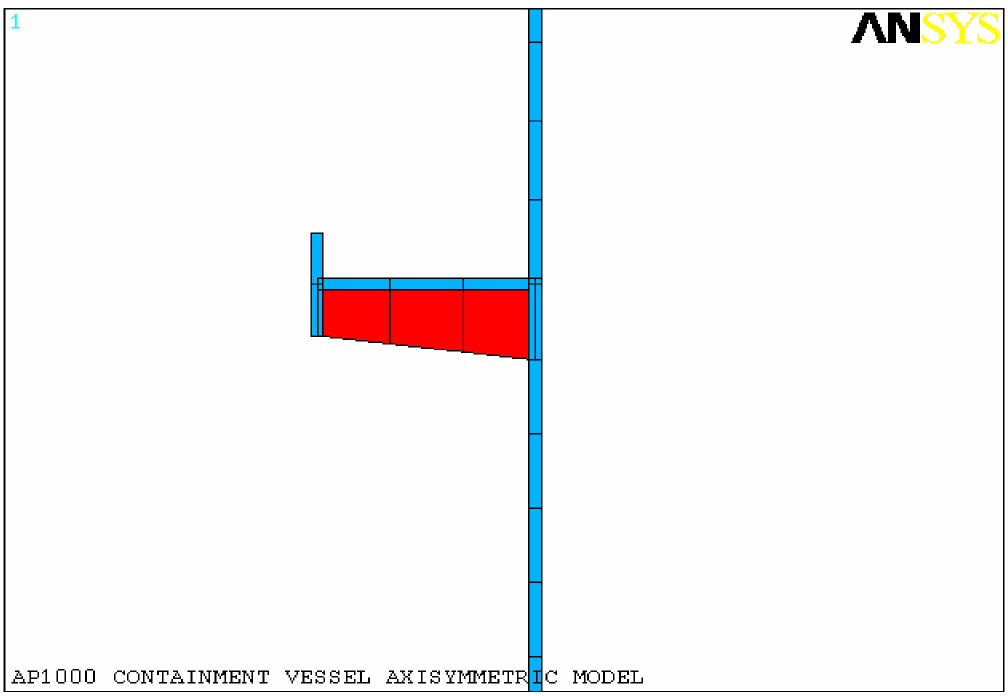


Figure 3.8.2-6 (Sheet 1 of 2)

Containment Vessel Axisymmetric Model



Crane Girder



Internal Stiffener at Elev. 170′-0″

Figure 3.8.2-6 (Sheet 2 of 2)

Containment Vessel Axisymmetric Model

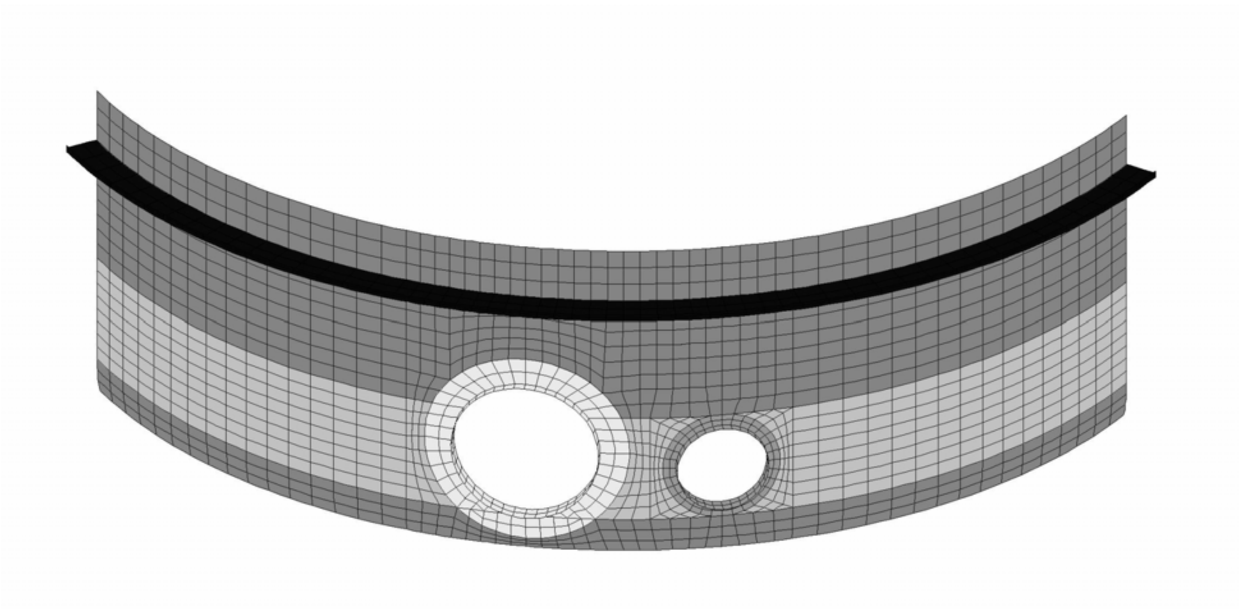


Figure 3.8.2-7

Finite Element Model for Local Buckling Analyses

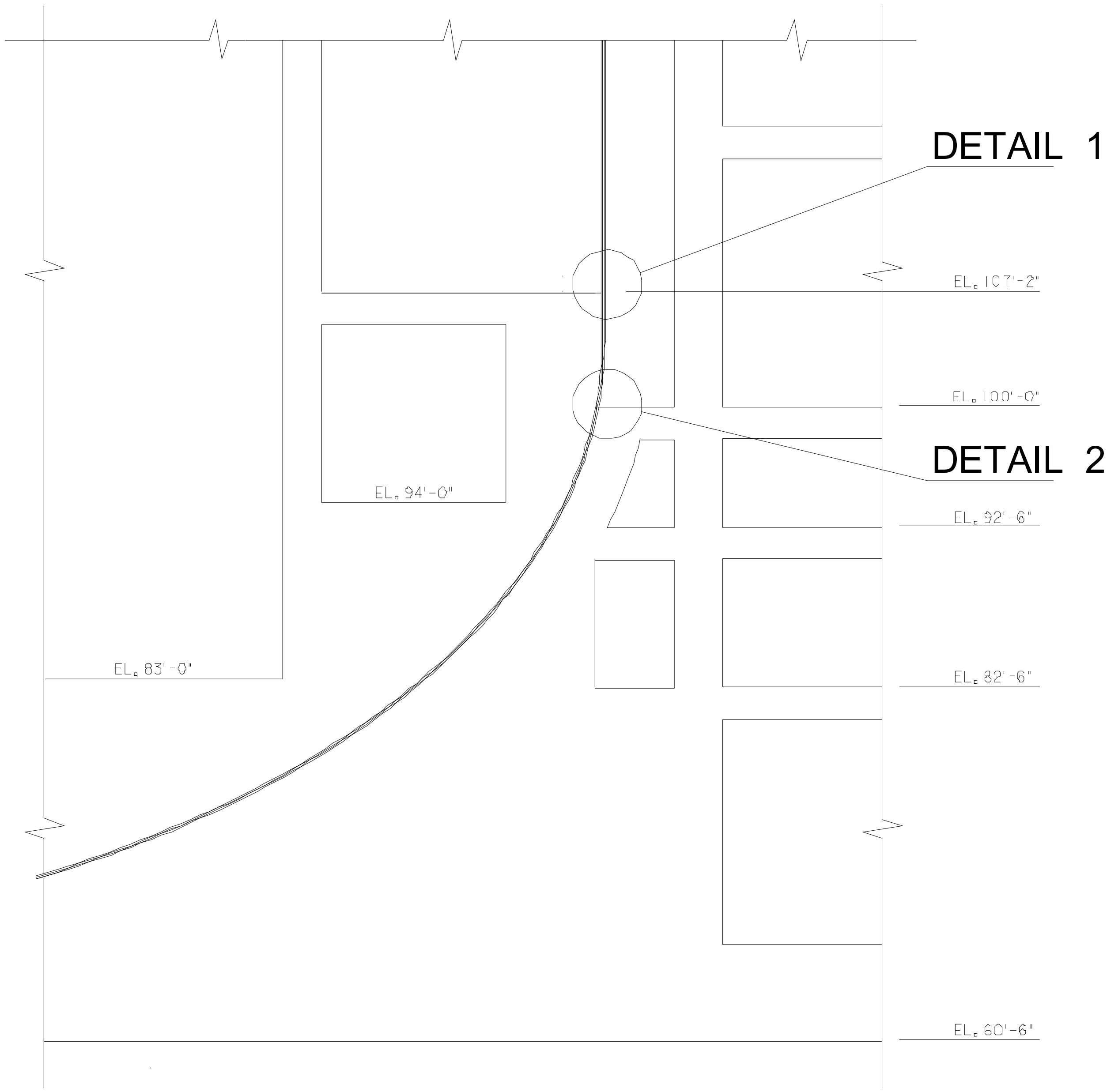


Figure 3.8.2-8 (Sheet 1 of 2)

Location of Containment Seal

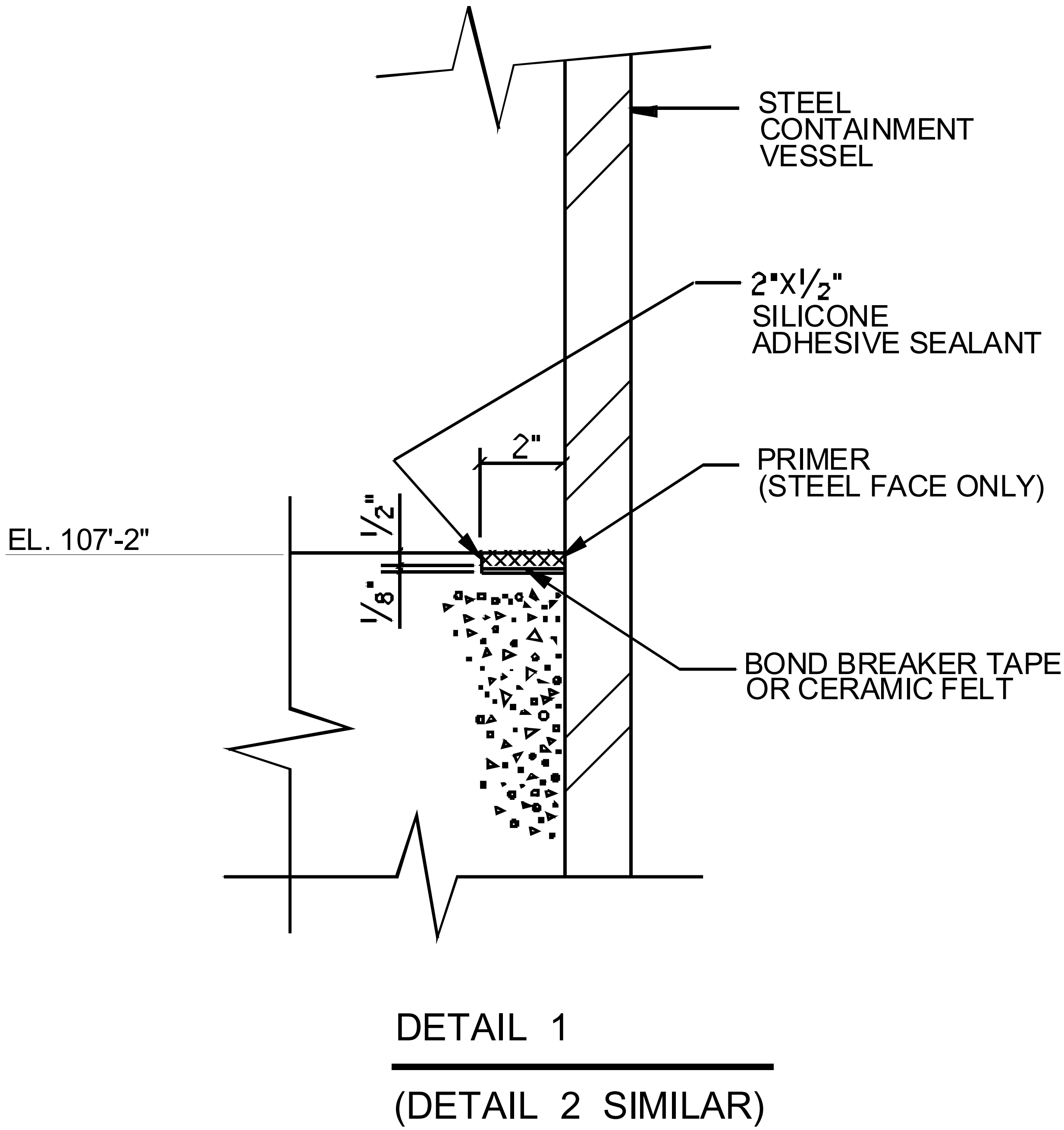


Figure 3.8.2-8 (Sheet 2 of 2)

Seal Sections and Details

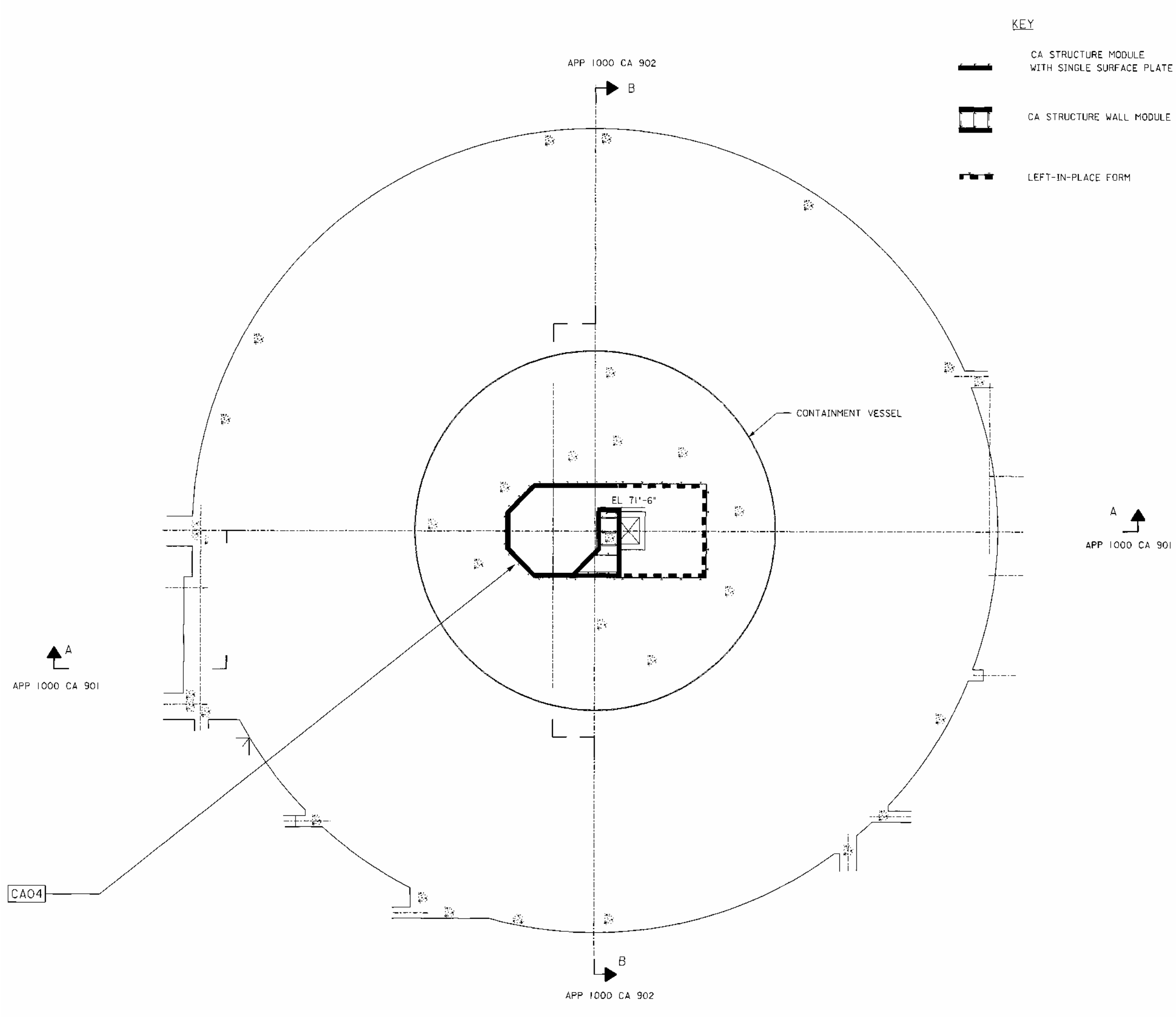


Figure 3.8.3-1 (Sheet 1 of 7)

[*Structural Modules in Containment Internal Structures*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

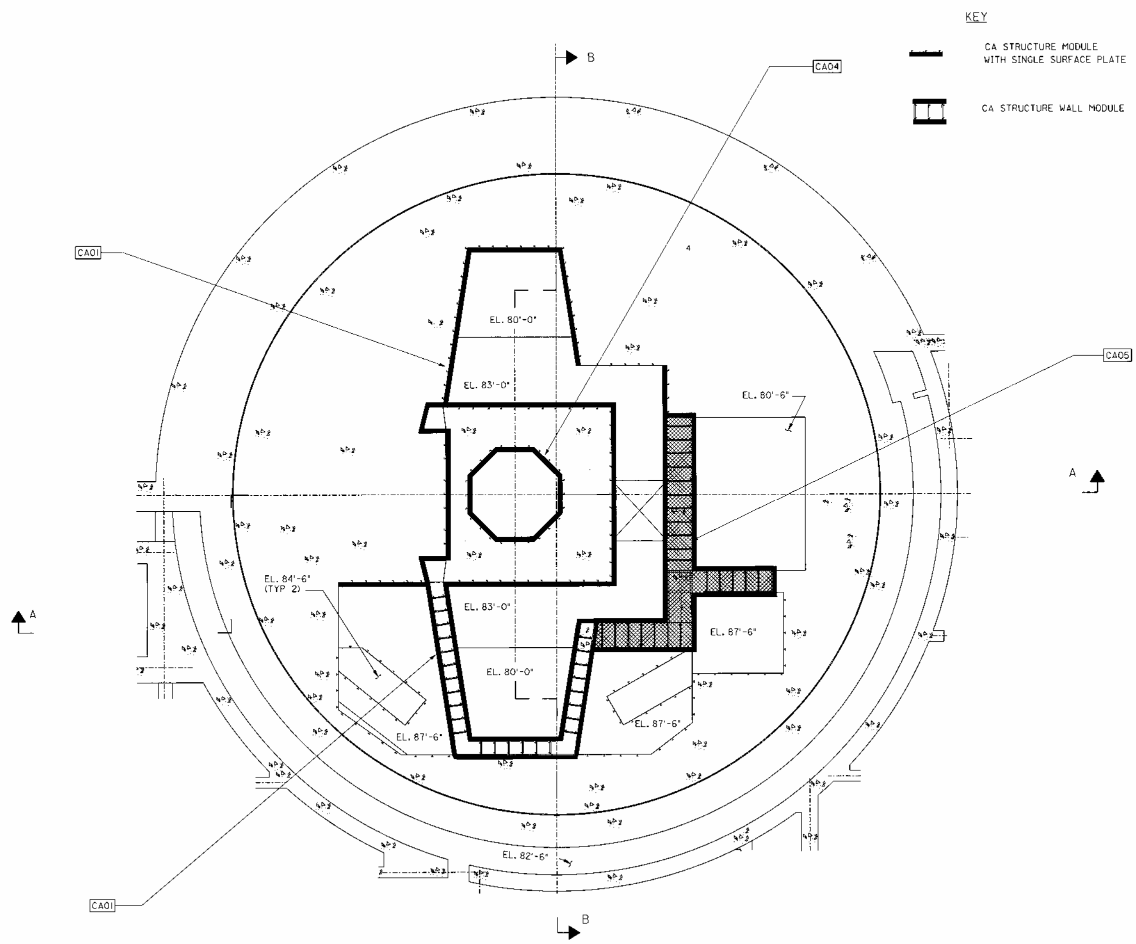


Figure 3.8.3-1 (Sheet 2 of 7)

[*Structural Modules in Containment Internal Structures*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

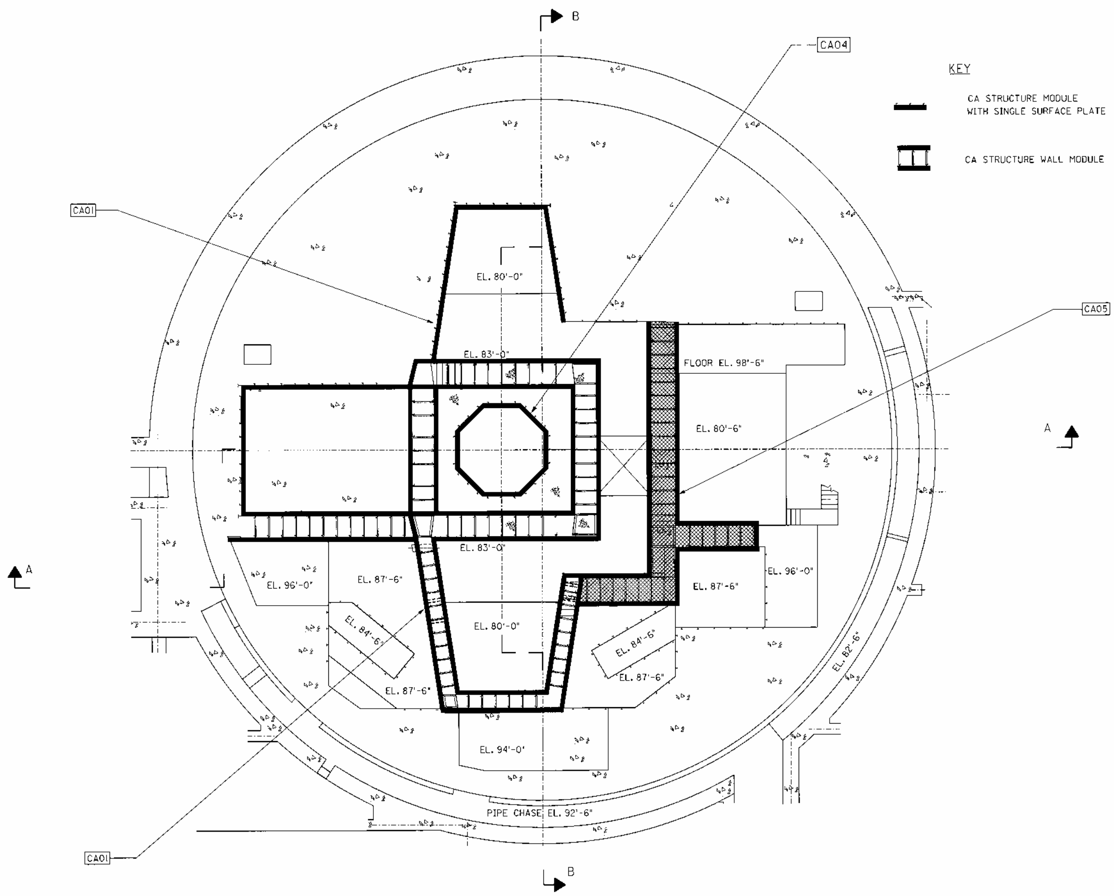


Figure 3.8.3-1 (Sheet 3 of 7)

[Structural Modules in Containment Internal Structures]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

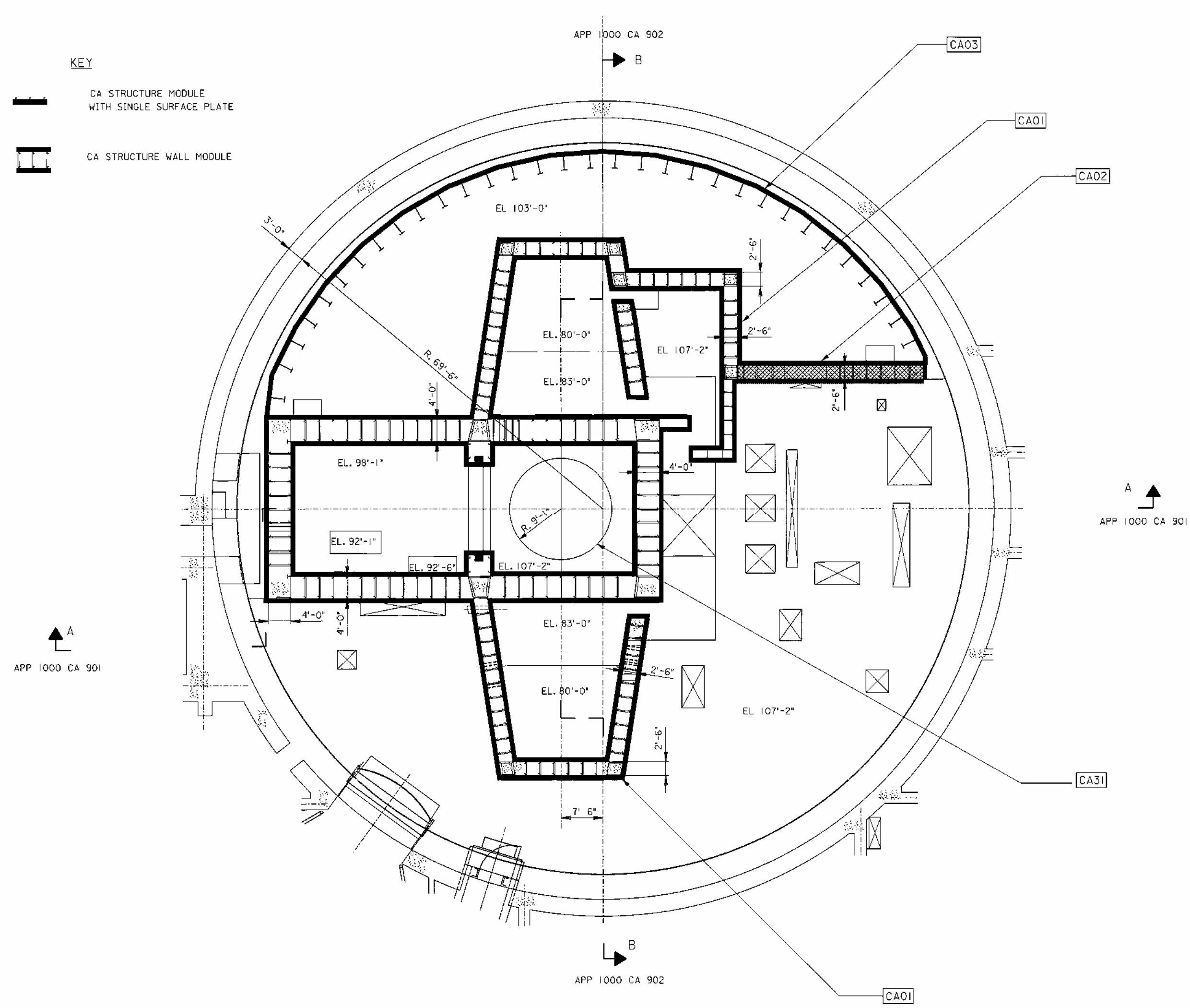


Figure 3.8.3-1 (Sheet 4 of 7)

[*Structural Modules in Containment Internal Structures*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

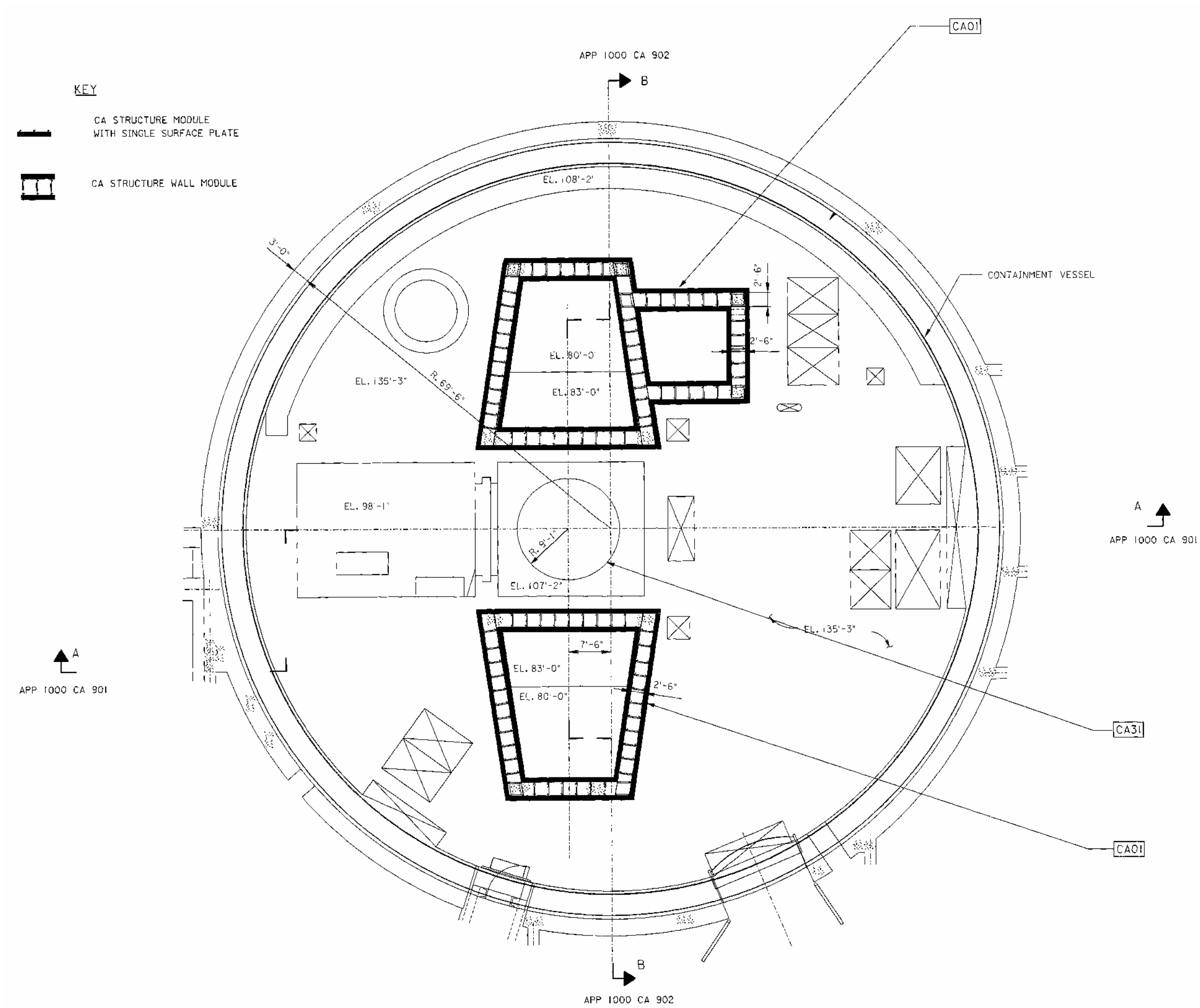


Figure 3.8.3-1 (Sheet 5 of 7)

[*Structural Modules in Containment Internal Structures*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

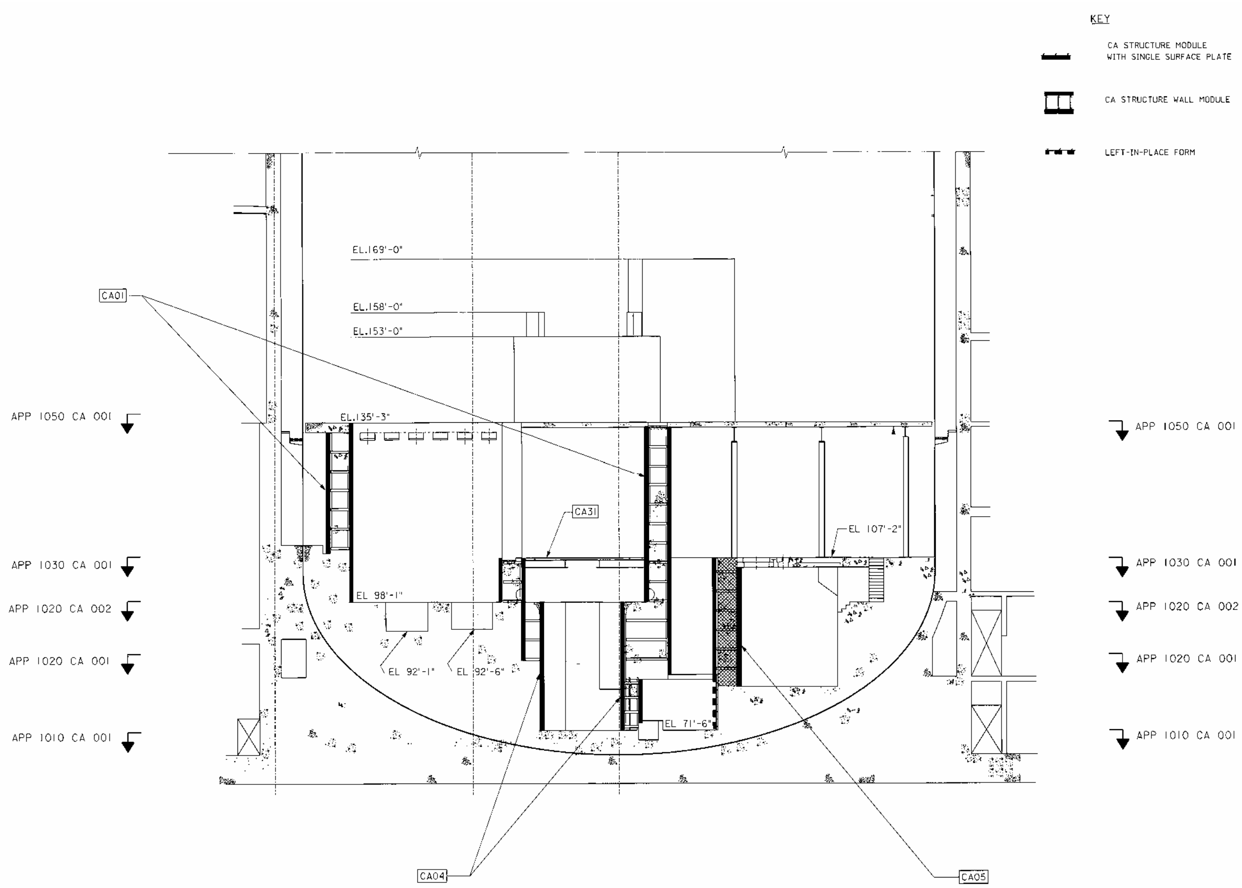


Figure 3.8.3-1 (Sheet 6 of 7)

[*Structural Modules in Containment Internal Structures*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

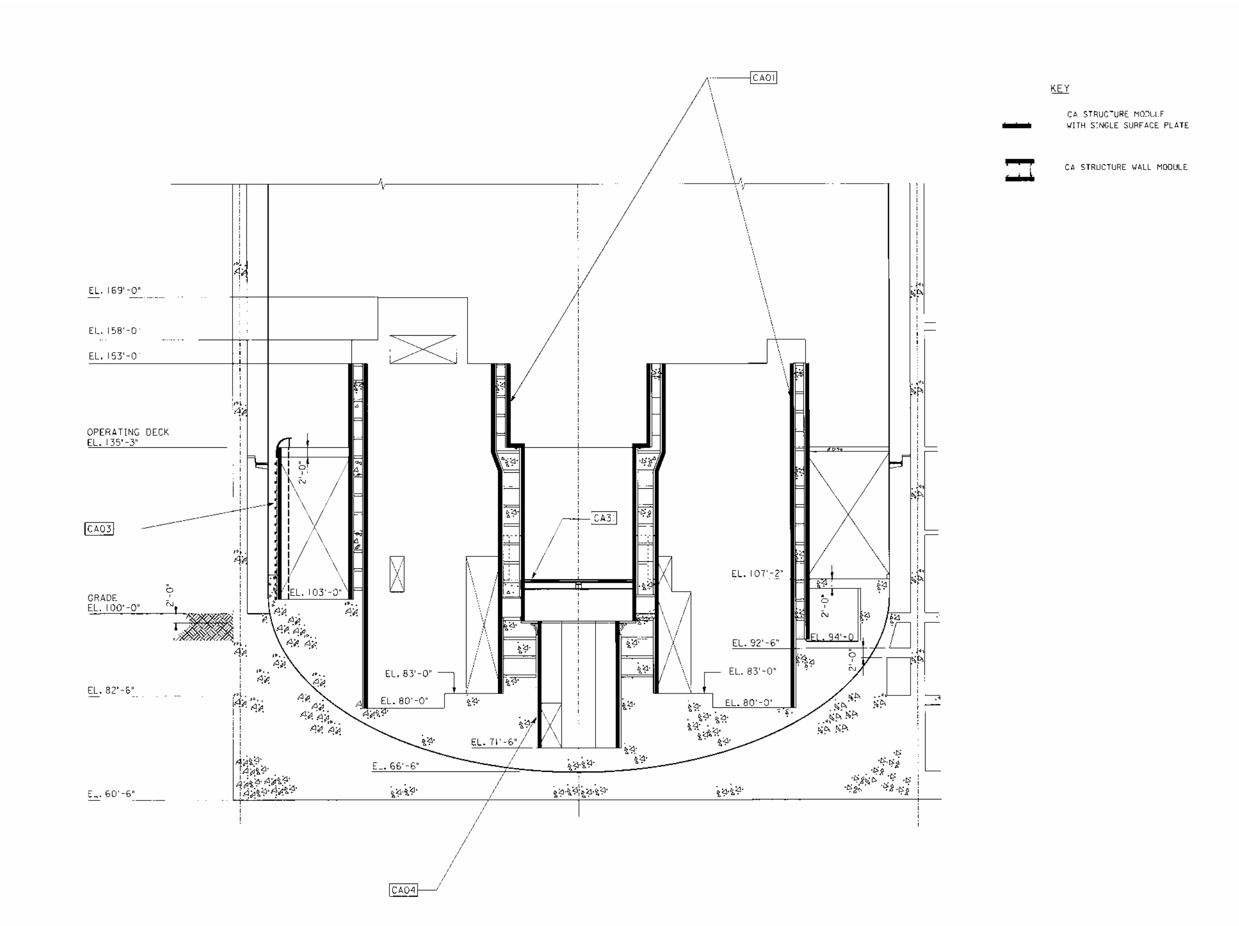


Figure 3.8.3-1 (Sheet 7 of 7)

[*Structural Modules in Containment Internal Structures*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

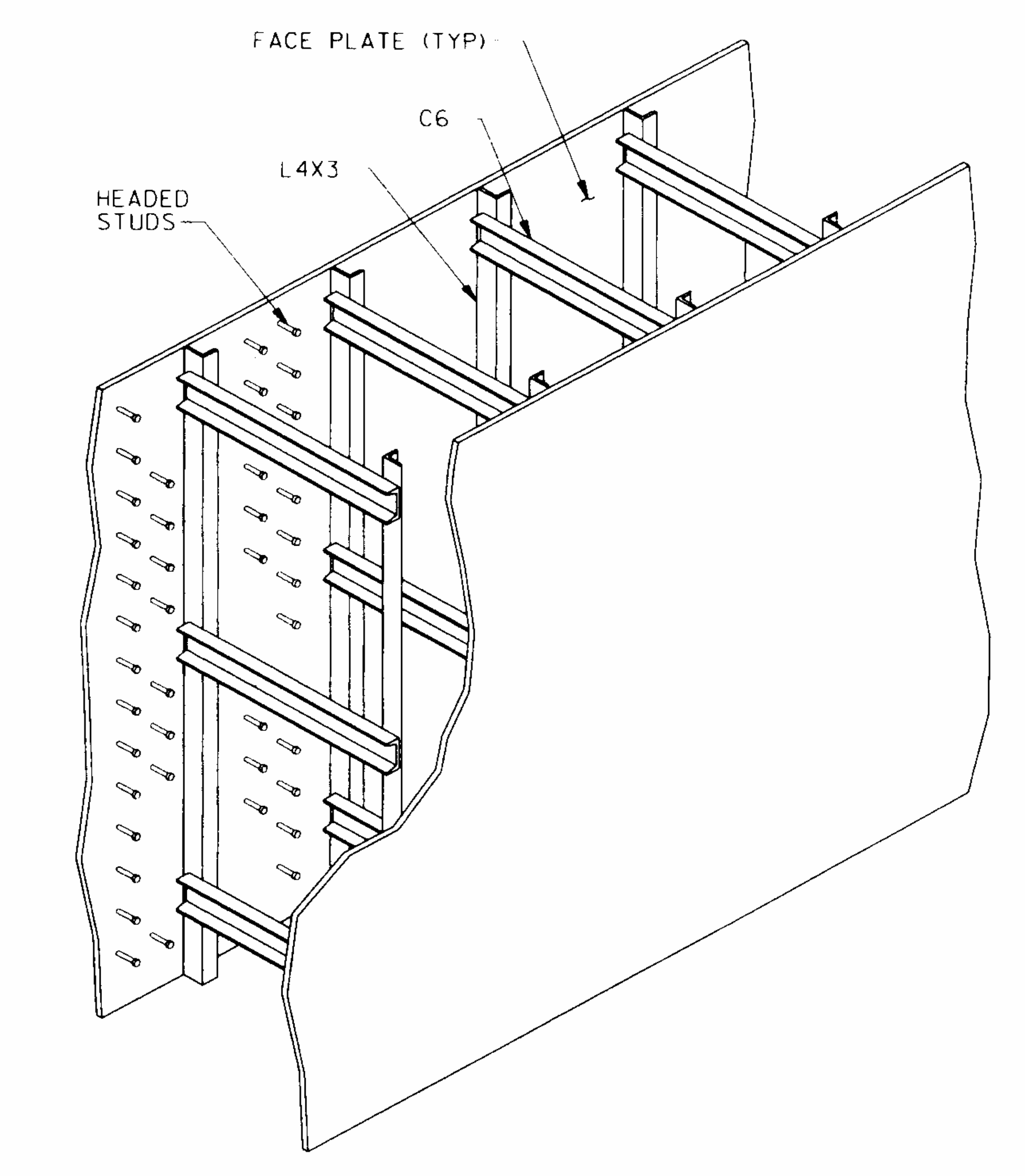


Figure 3.8.3-2

[*Typical Structural Wall Module*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

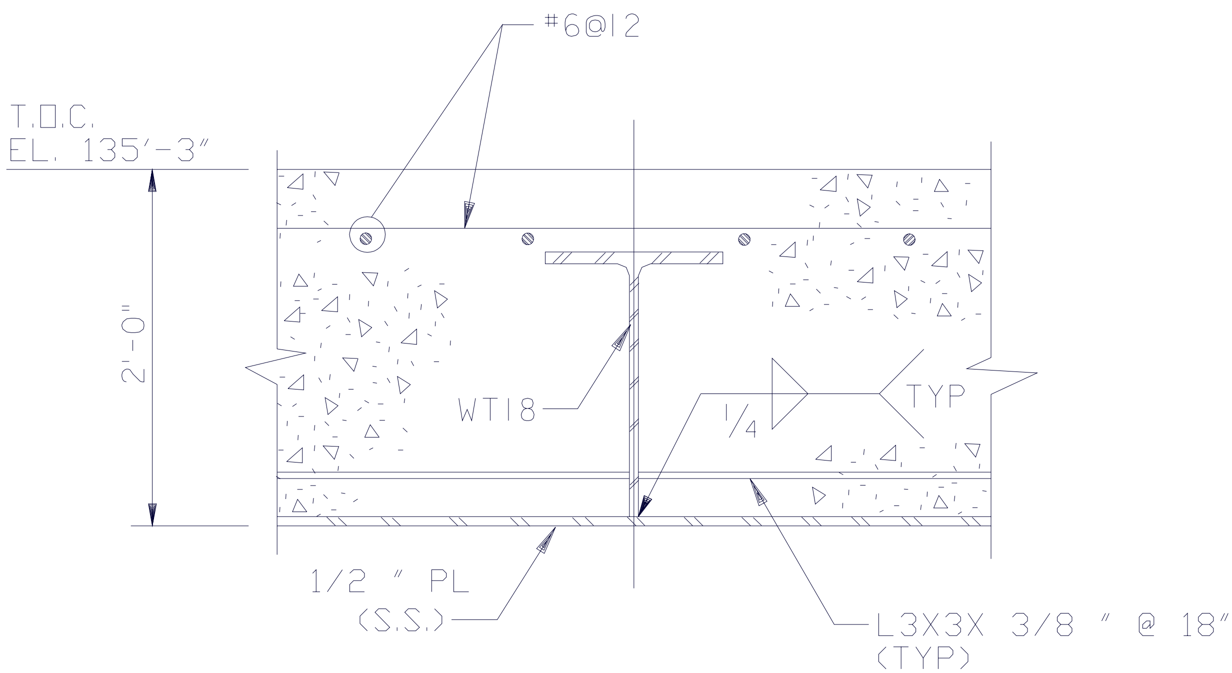


Figure 3.8.3-3

Typical Structural Floor Module

[This page intentionally blank]

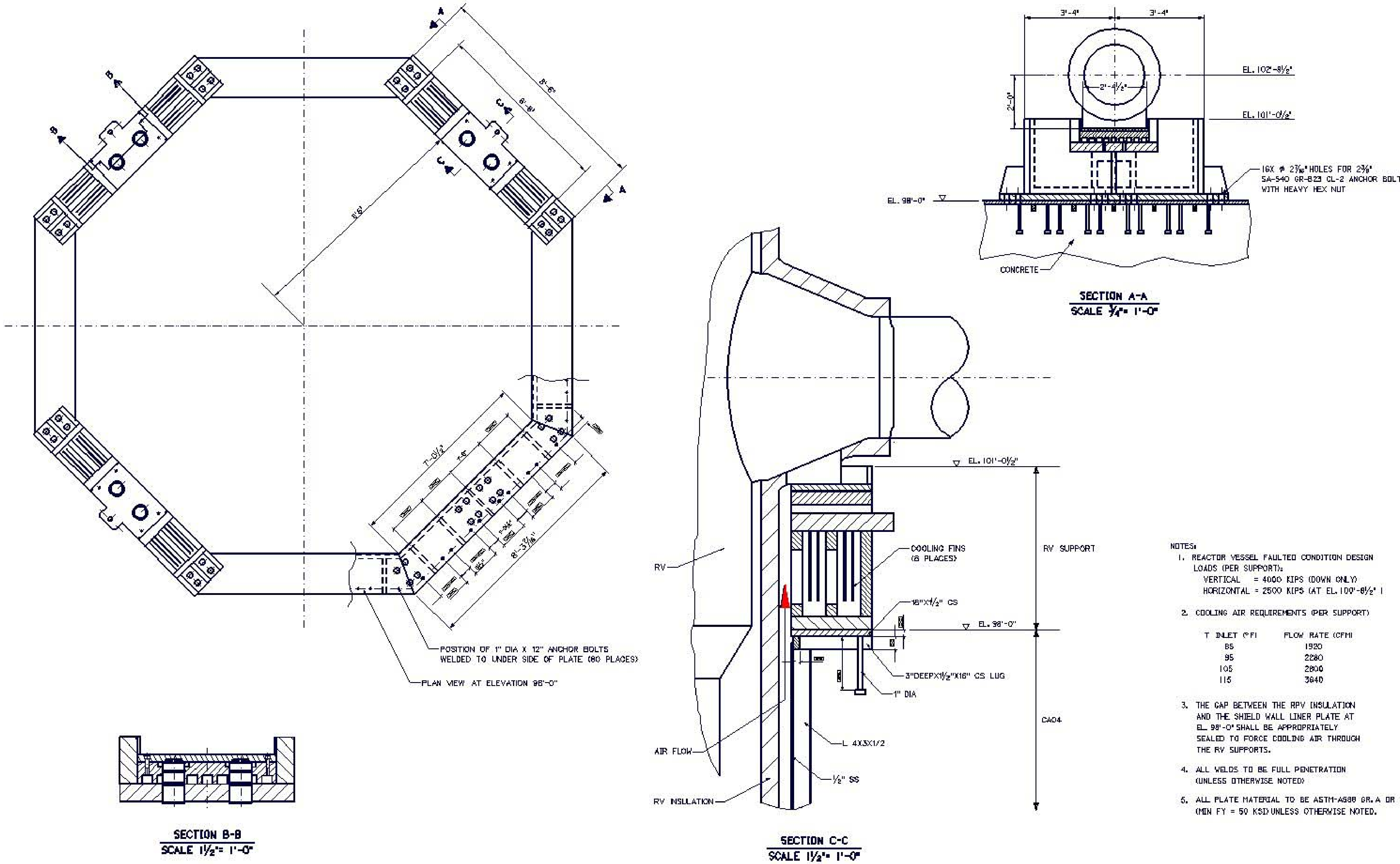
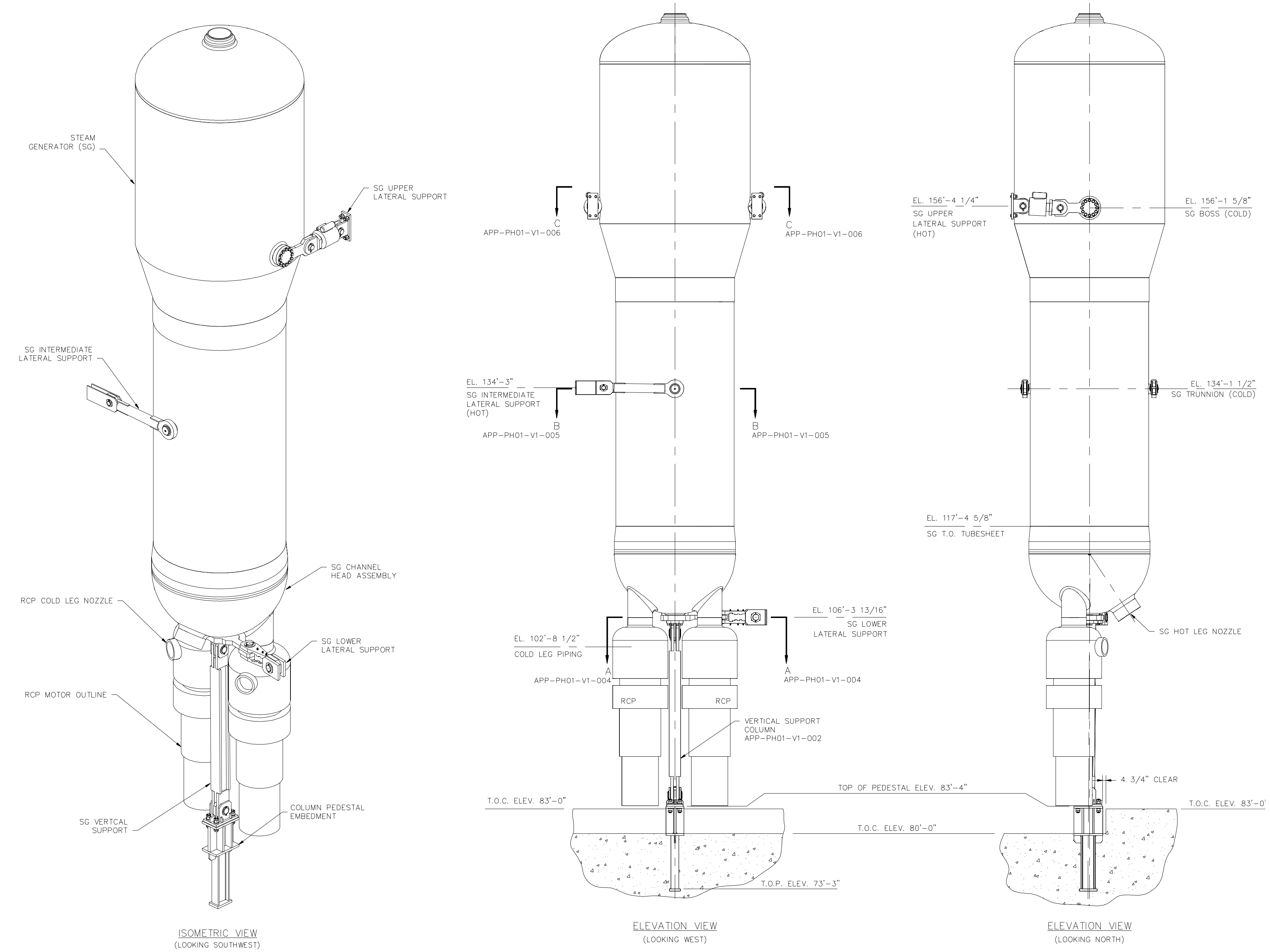


Figure 3.8.3-4

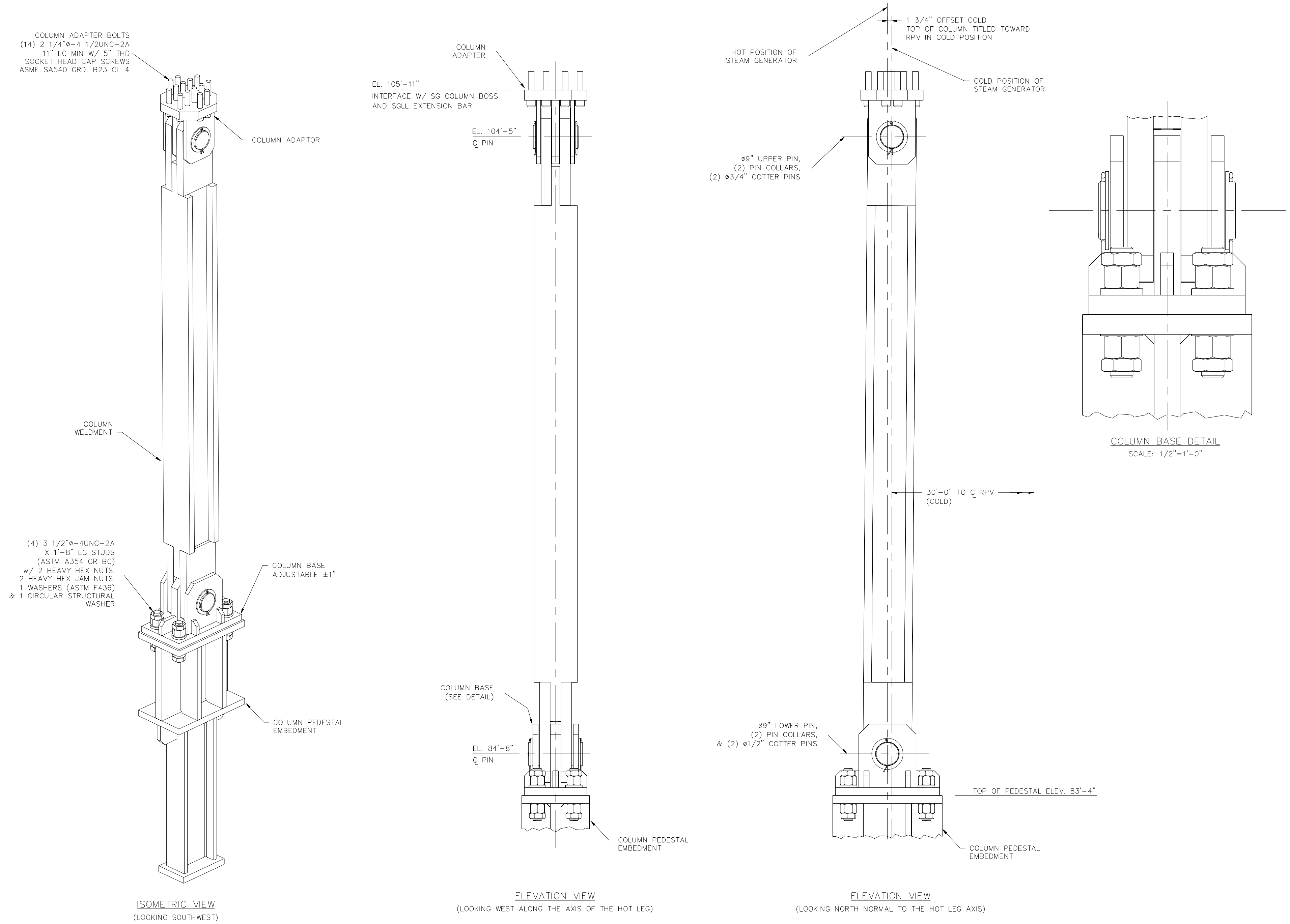
Reactor Vessel Supports



SG Support Assembly

Figure 3.8.3-5 (Sheet 1 of 5)

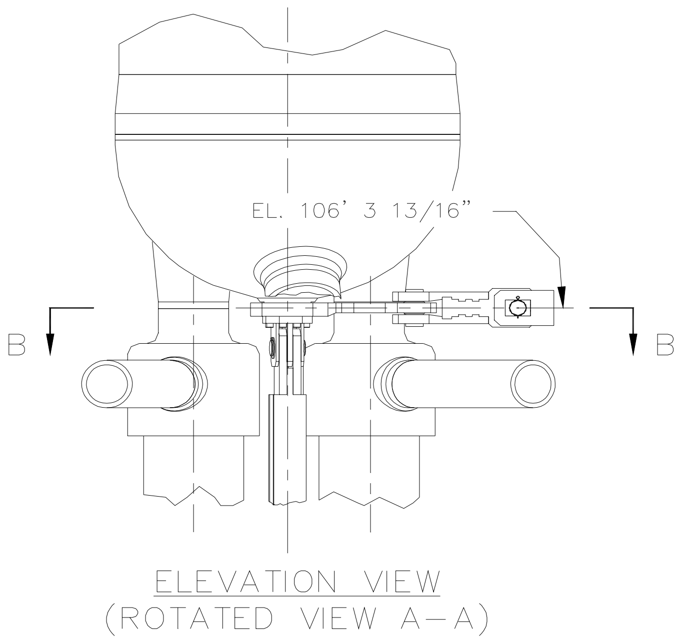
Steam Generator Supports



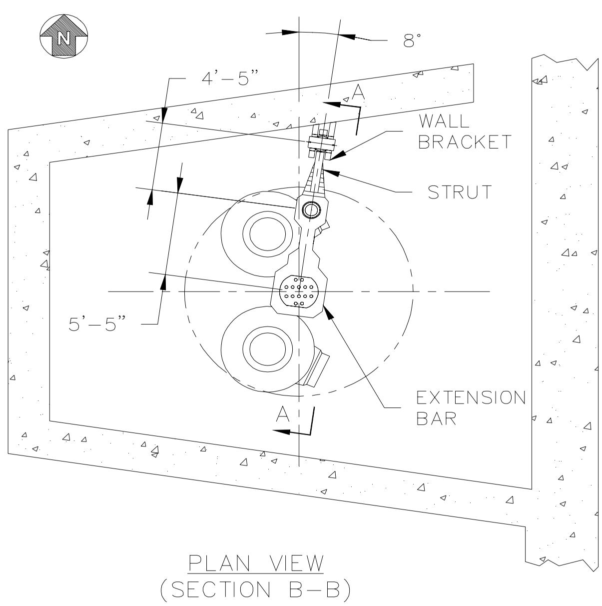
SG Vertical Support Column

Figure 3.8.3-5 (Sheet 2 of 5)

Steam Generator Supports



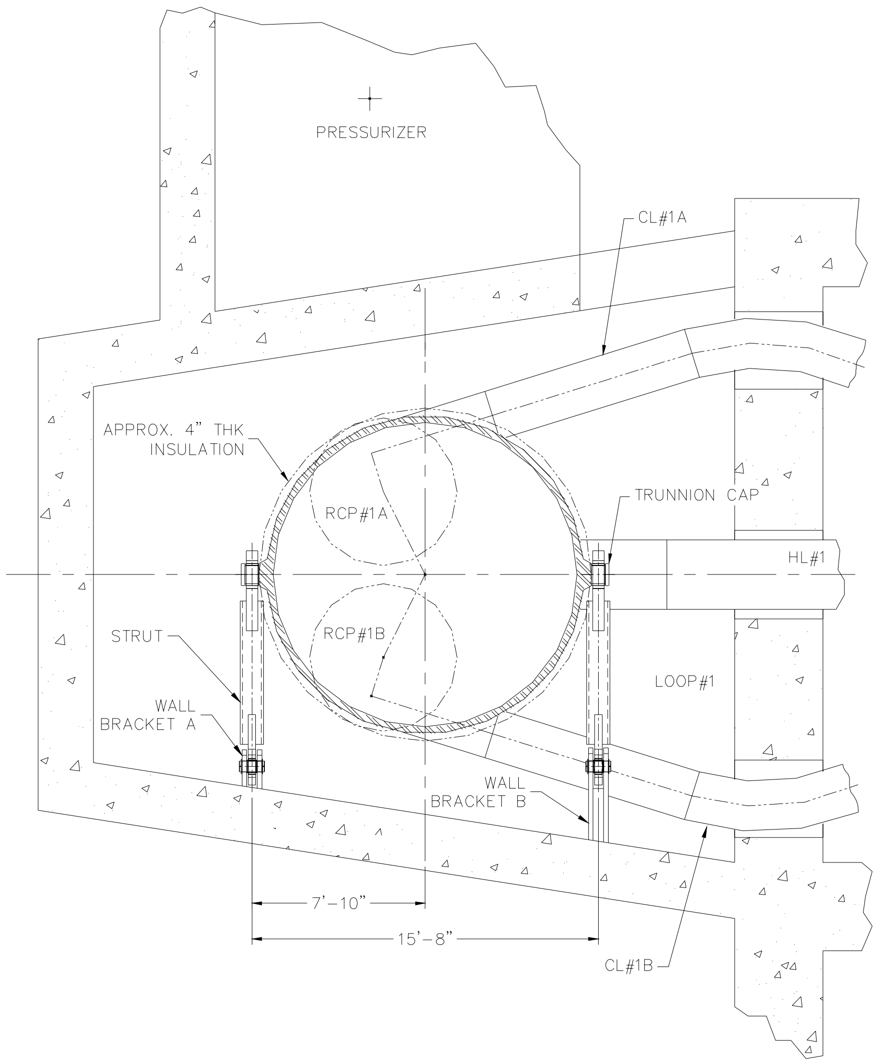
Lower Lateral Support Elevation View



Lower Lateral Support Plan View

Figure 3.8.3-5 (Sheet 3 of 5)

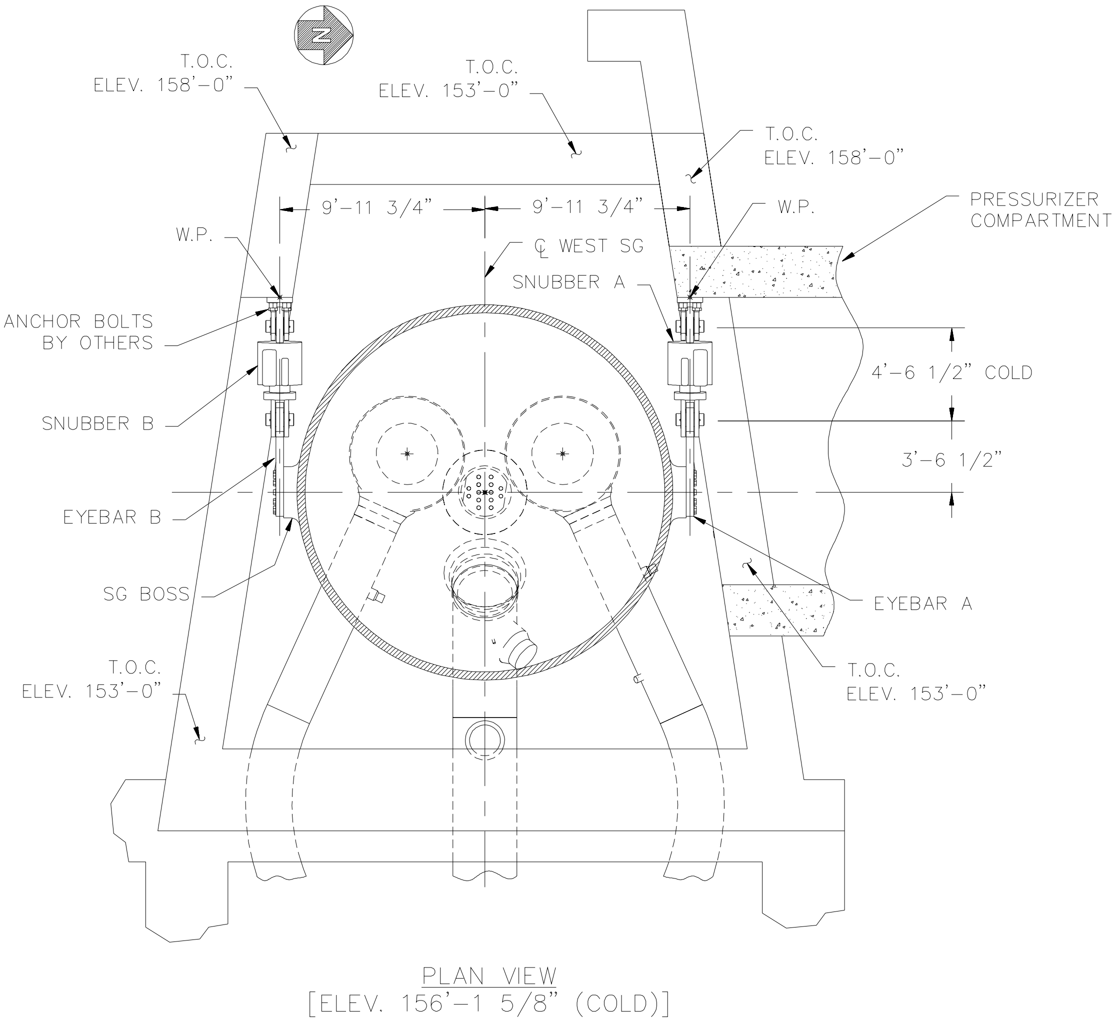
Steam Generator Supports



Intermediate Lateral Support

Figure 3.8.3-5 (Sheet 4 of 5)

Steam Generator Supports



Upper Lateral Support

Figure 3.8.3-5 (Sheet 5 of 5)

Steam Generator Supports

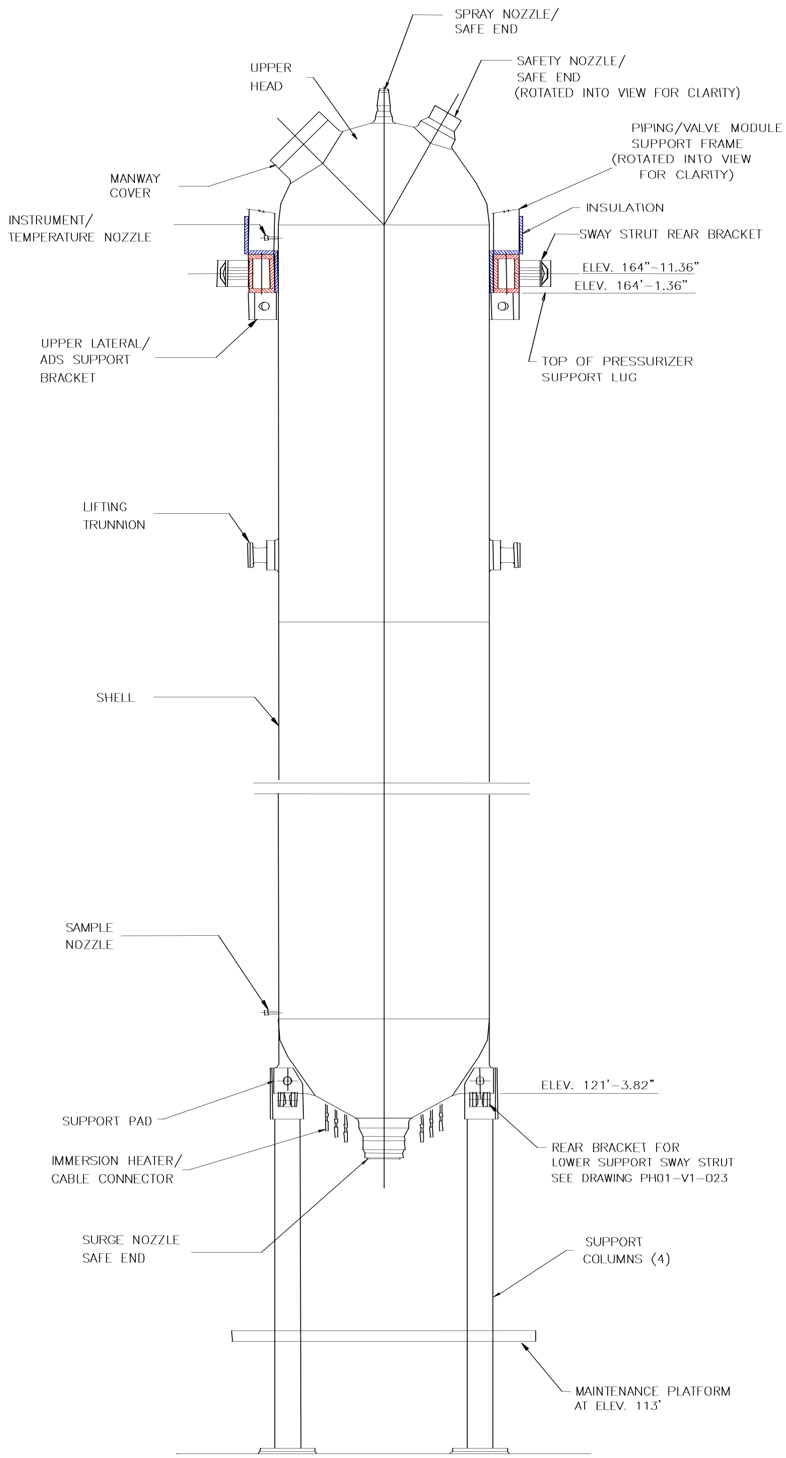


Figure 3.8.3-6 (Sheet 1 of 4)

Pressurizer Support Columns

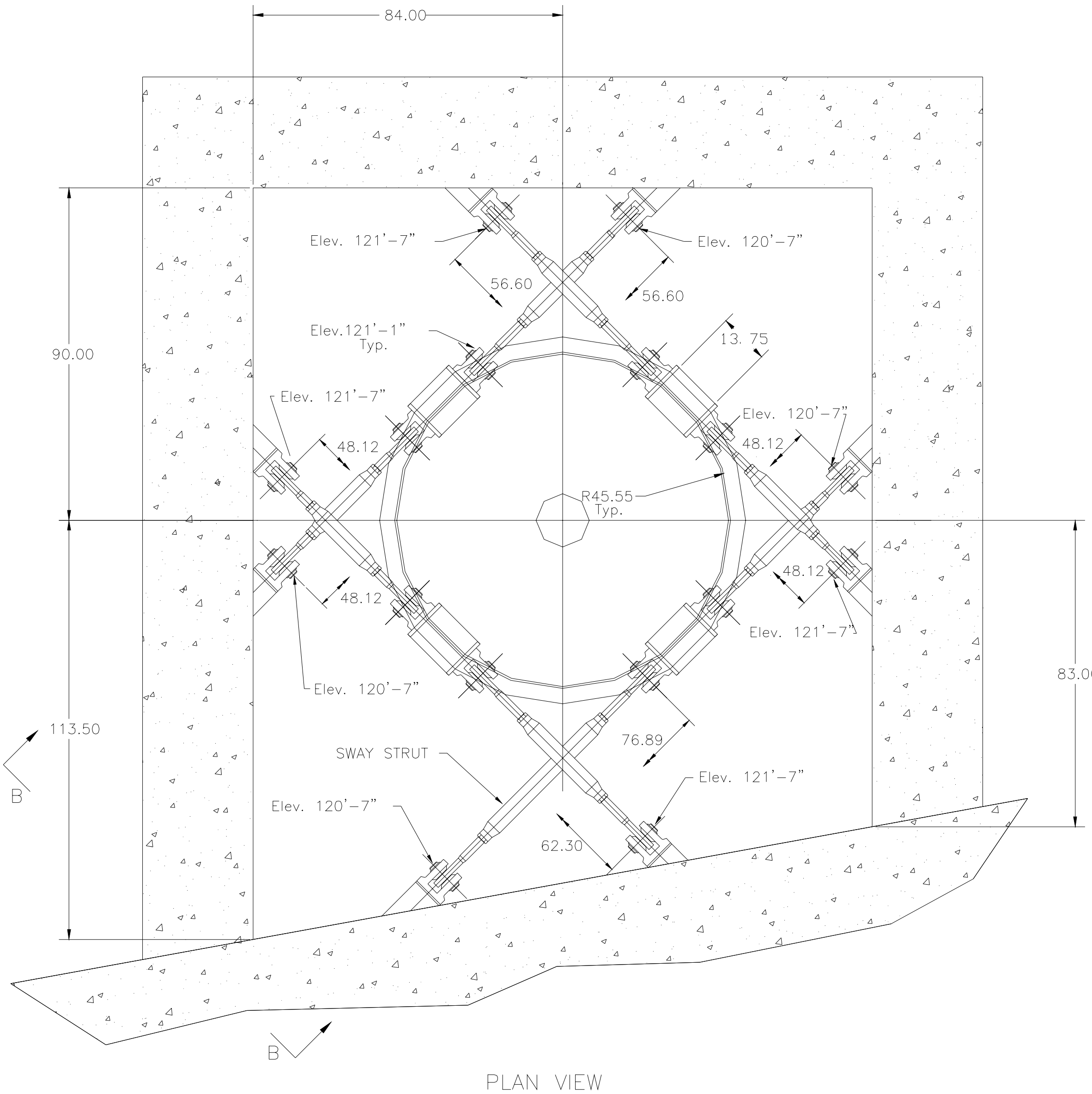


Figure 3.8.3-6 (Sheet 2 of 4)

Pressurizer Lower Lateral Supports

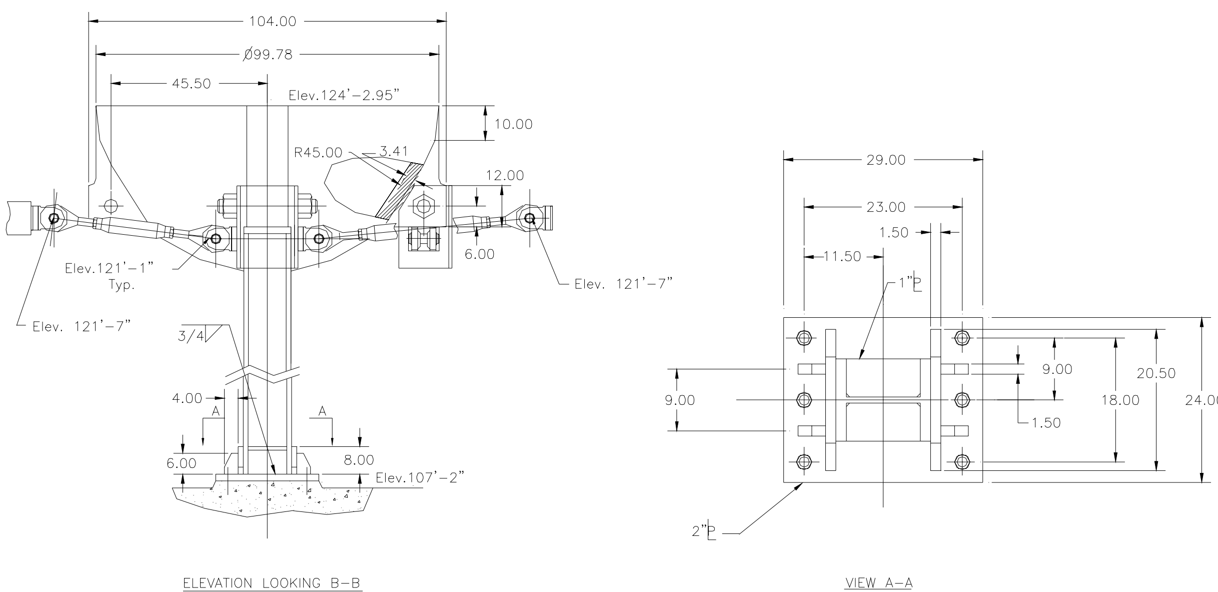


Figure 3.8.3-6 (Sheet 3 of 4)

Pressurizer Lower Supports

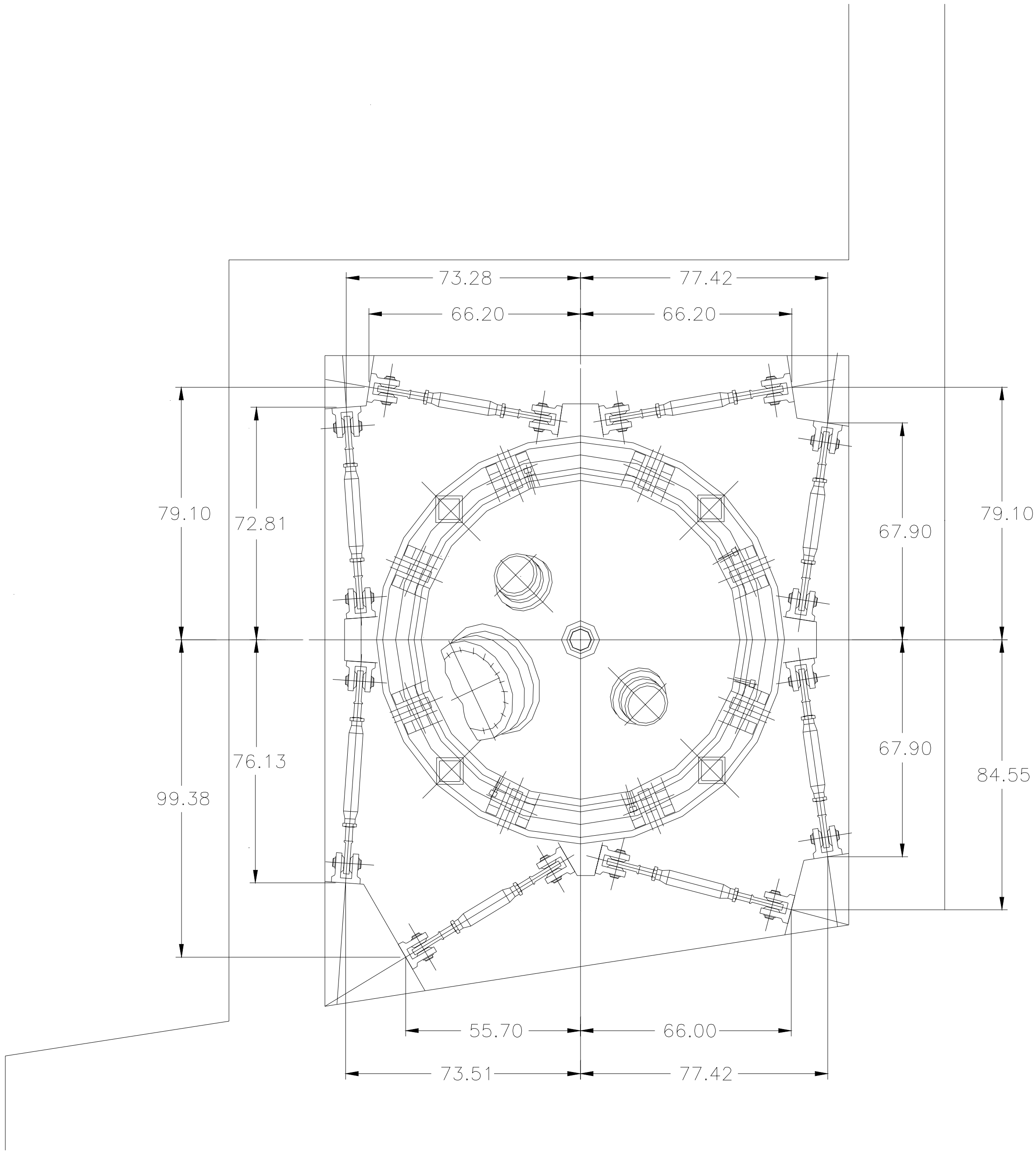


Figure 3.8.3-6 (Sheet 4 of 4)

Pressurizer Upper Supports

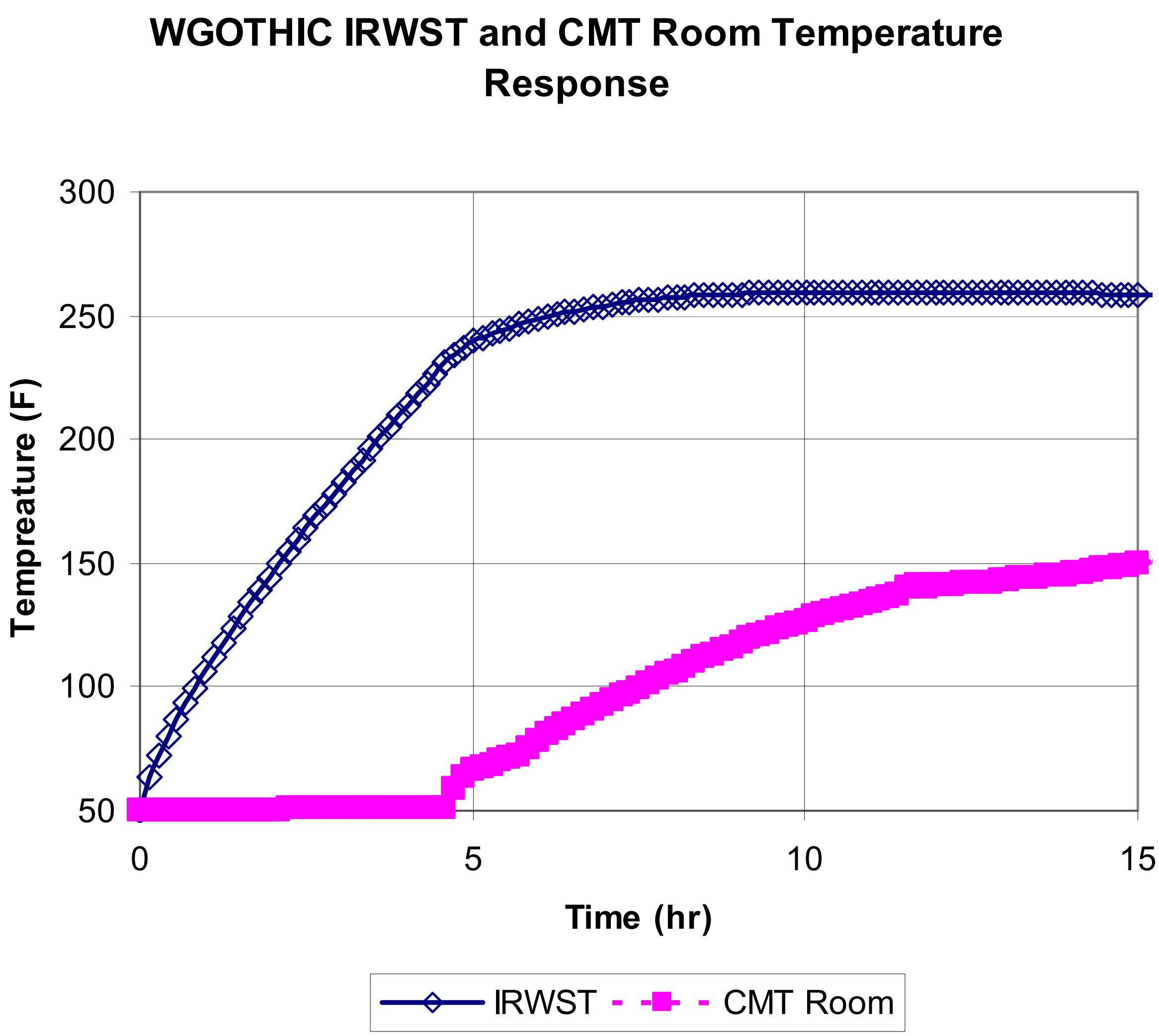


Figure 3.8.3-7

IRWST Temperature Transient

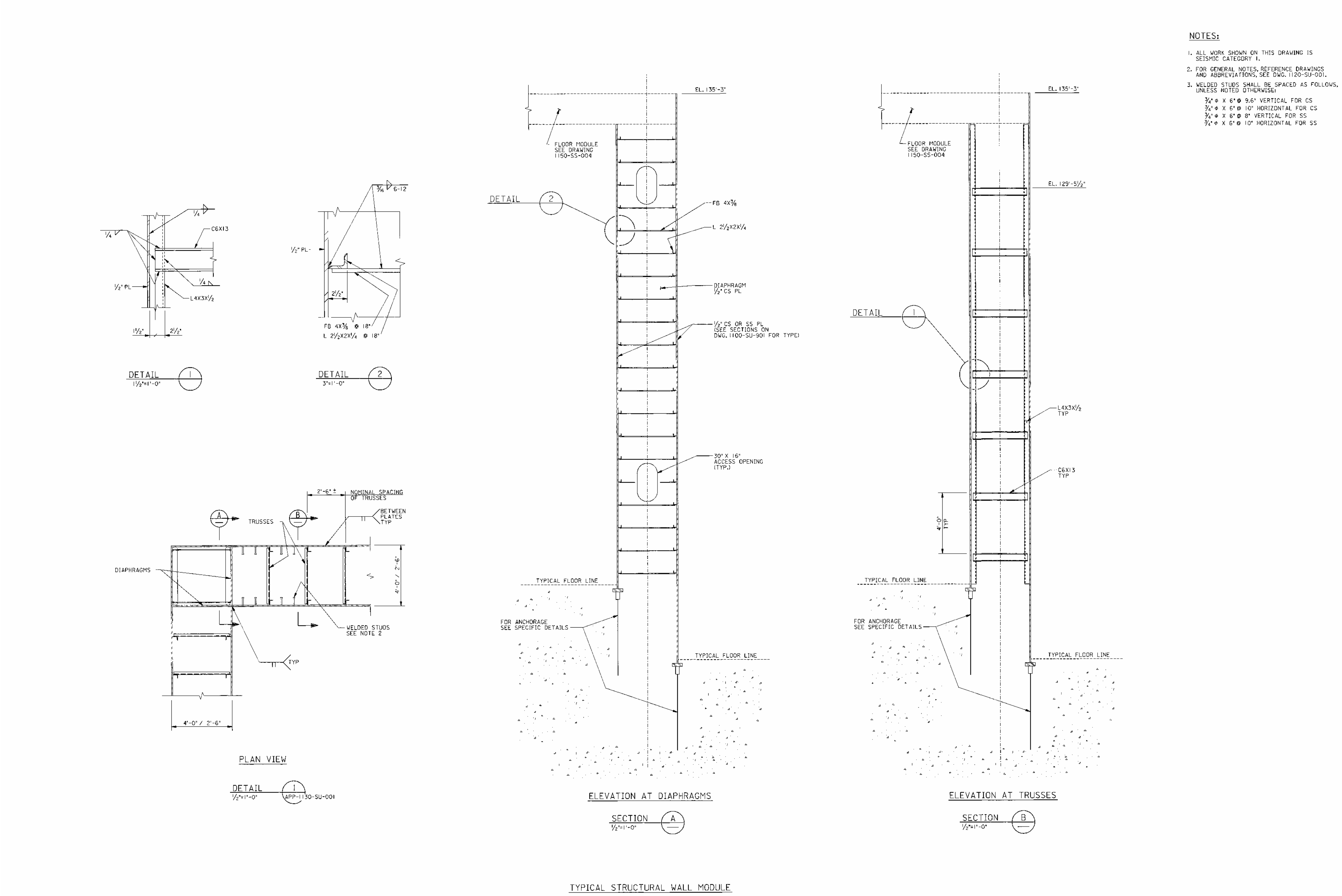


Figure 3.8.3-8 (Sheet 1 of 3)

[*Structural Modules – Typical Design Details*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

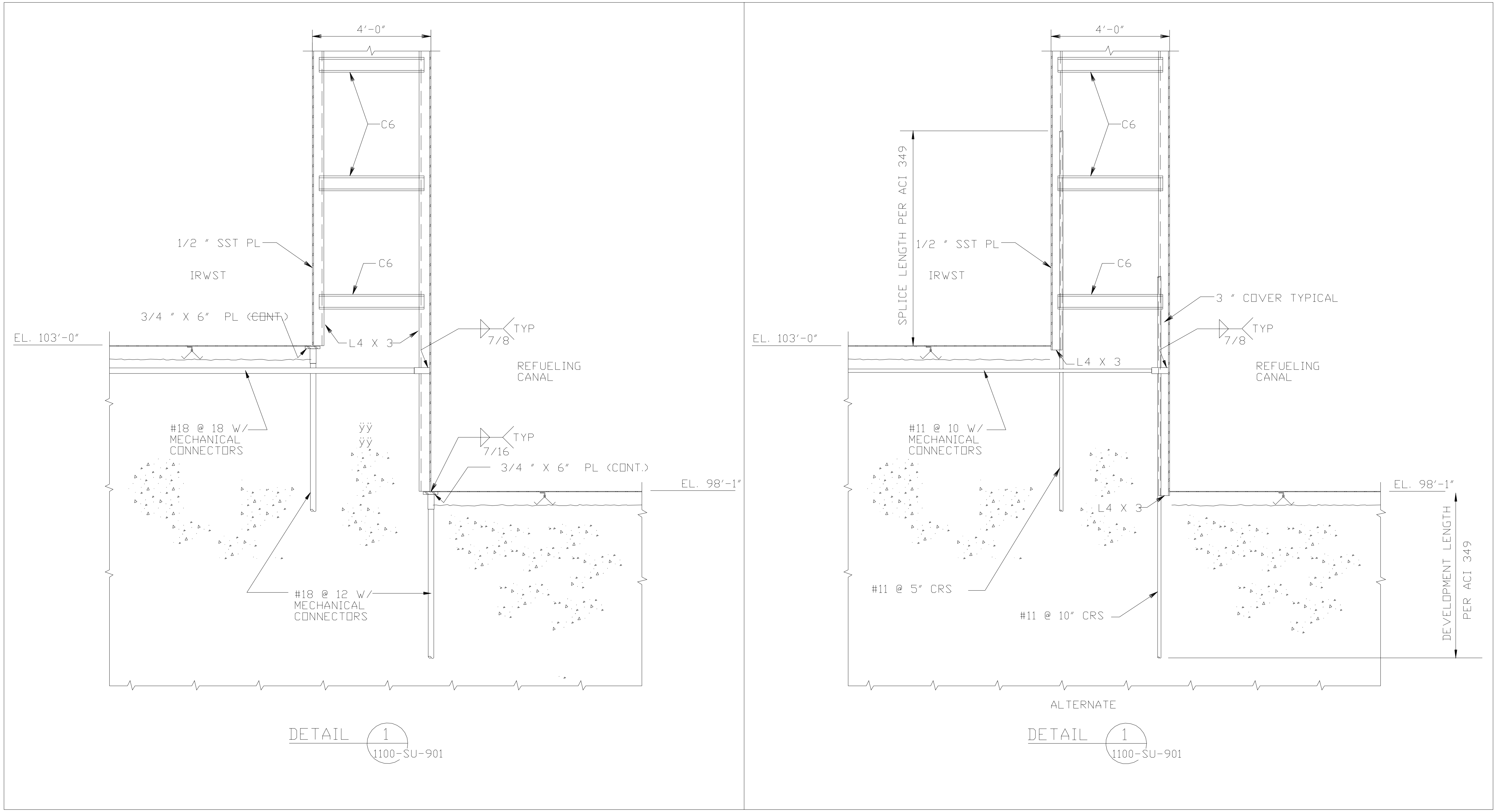


Figure 3.8.3-8 (Sheet 2 of 3)

[*Structural Modules – Typical Design Details*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

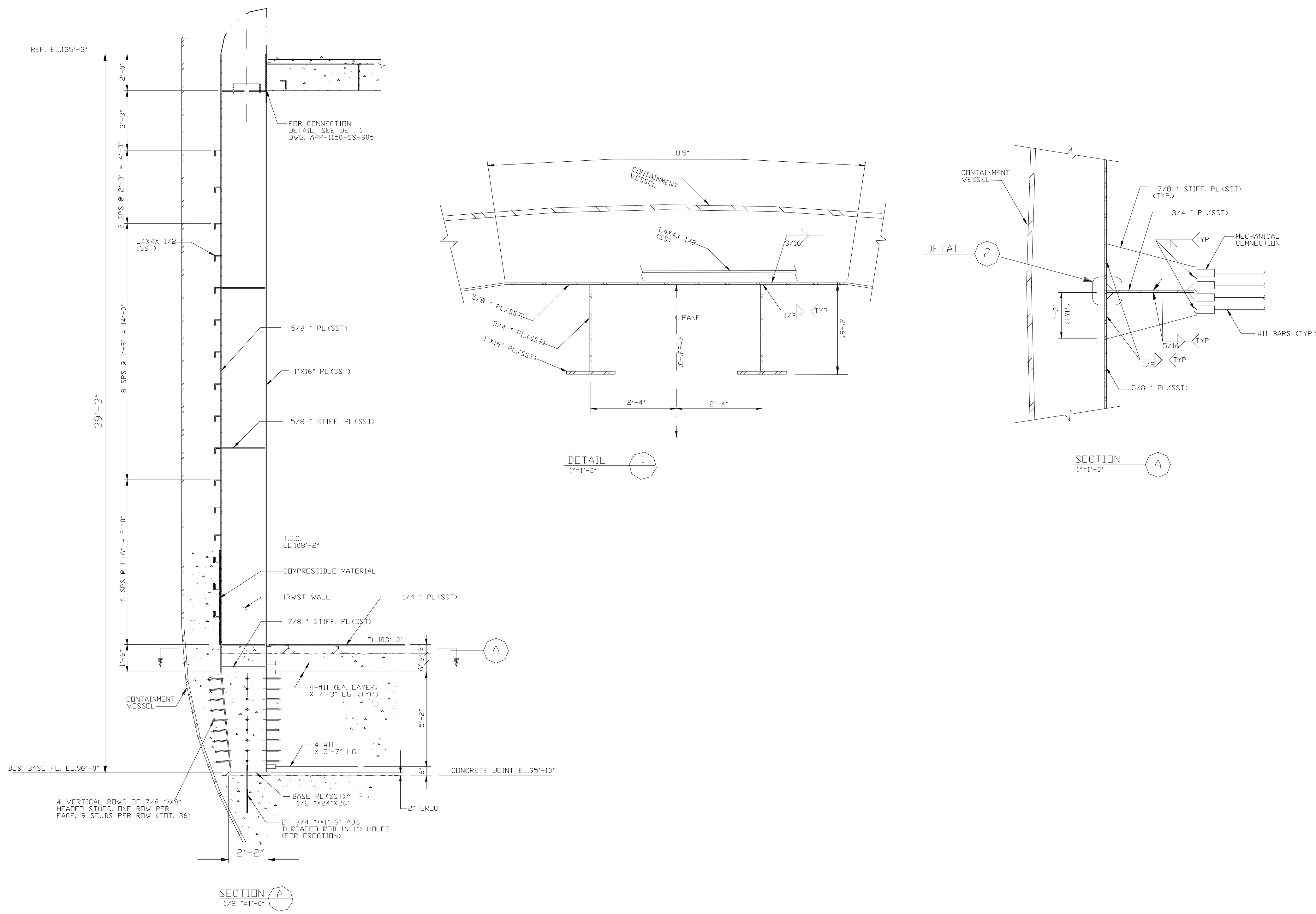


Figure 3.8.3-8 (Sheet 3 of 3)

[*Structural Modules – Typical Design Details*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

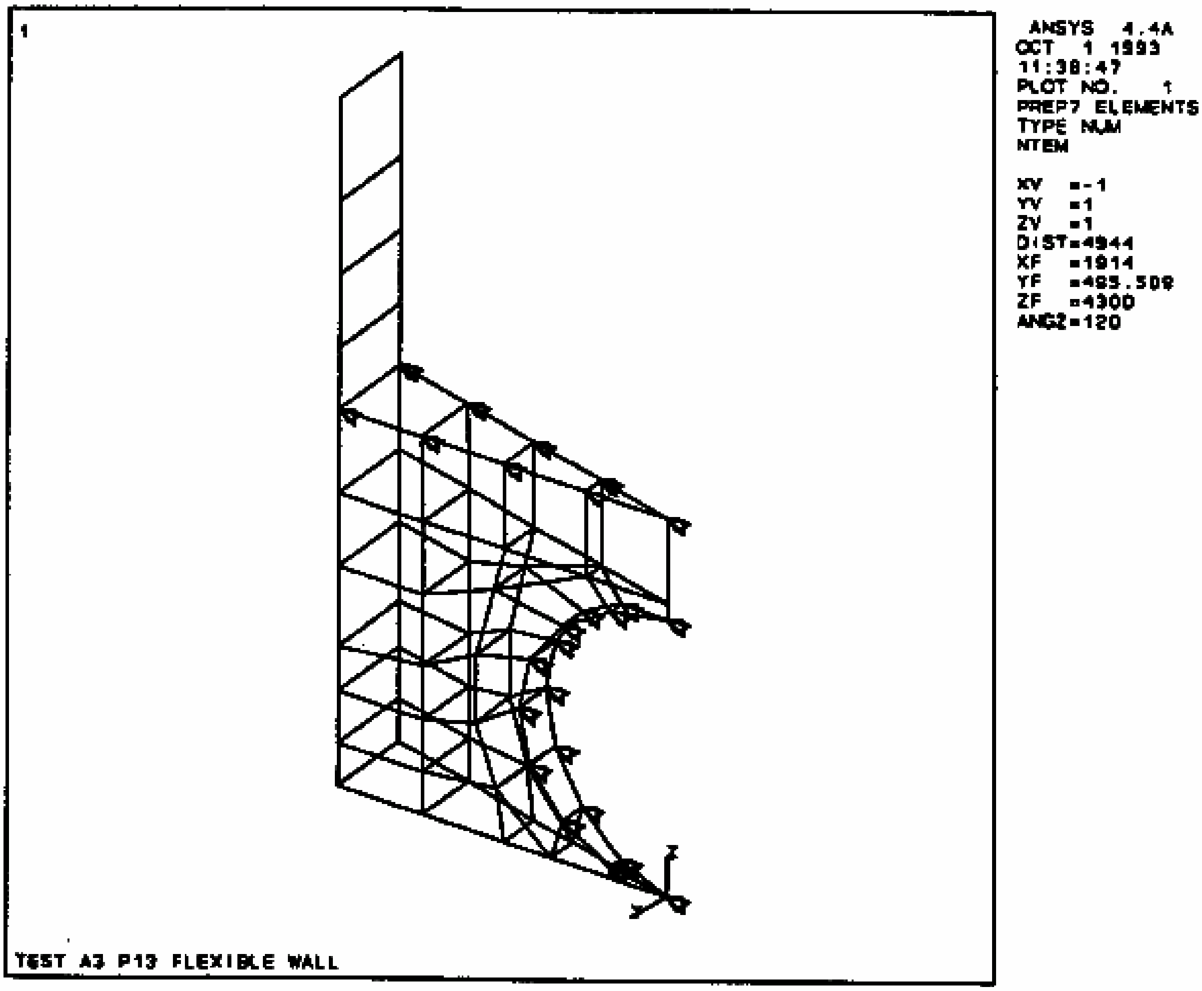


Figure 3.8.3-9

Test Tank Finite Element Model

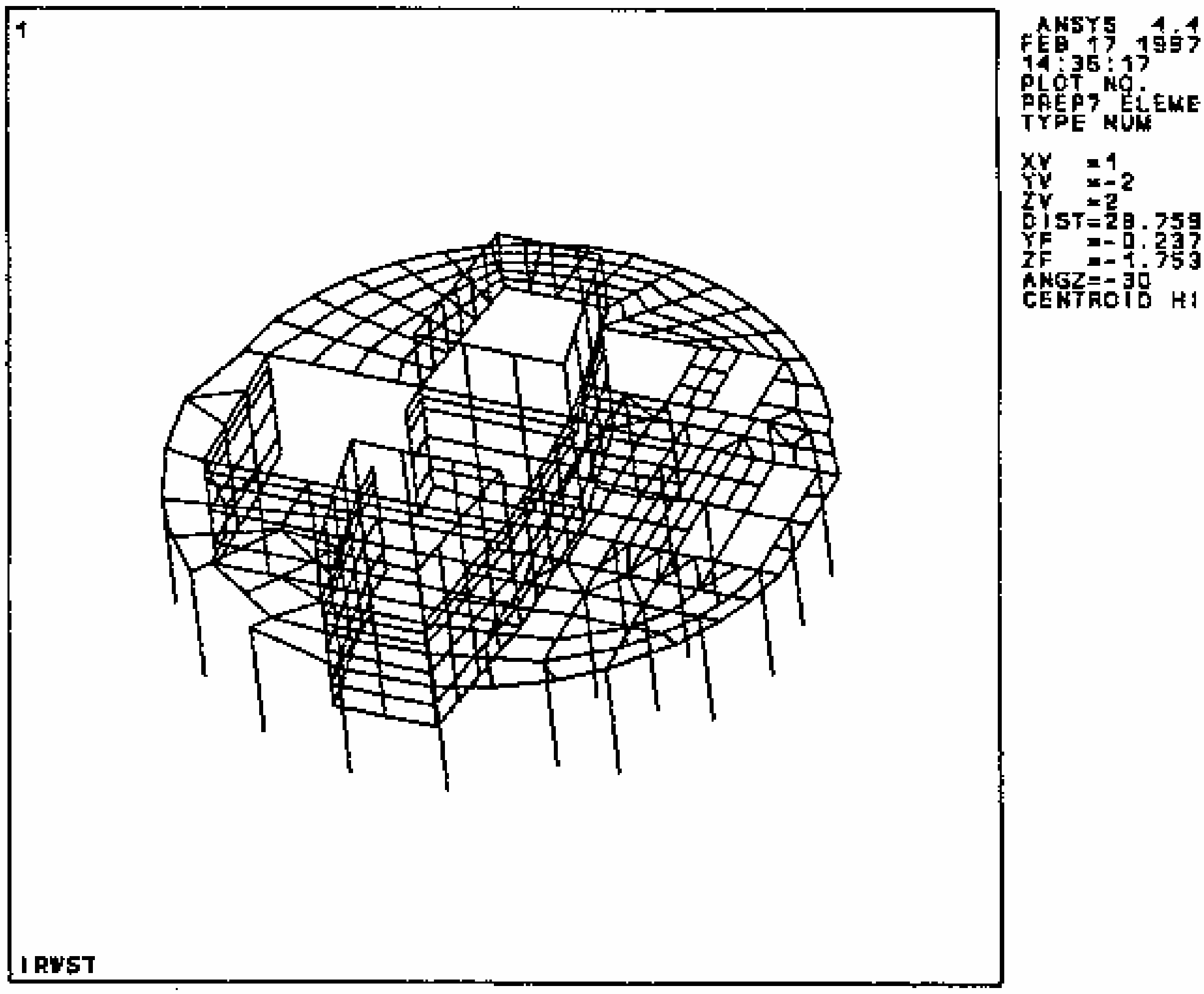


Figure 3.8.3-10 (Sheet 1 of 2)

**IRWST Fluid Structure Finite Element Model
CIS Structural Model**

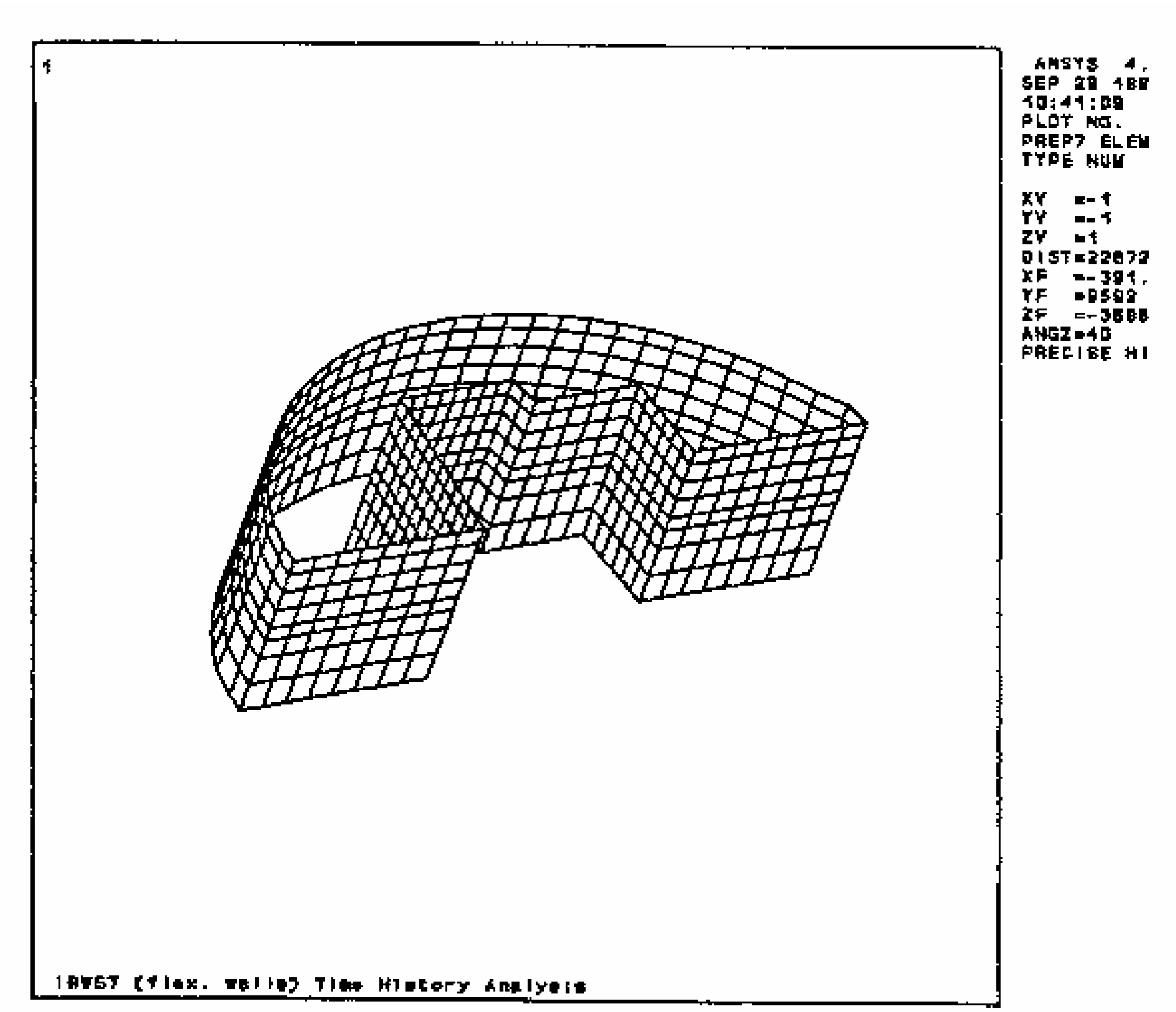


Figure 3.8.3-10 (Sheet 2 of 2)

IRWST Fluid Structure Finite Element Model
IRWST Structural Model

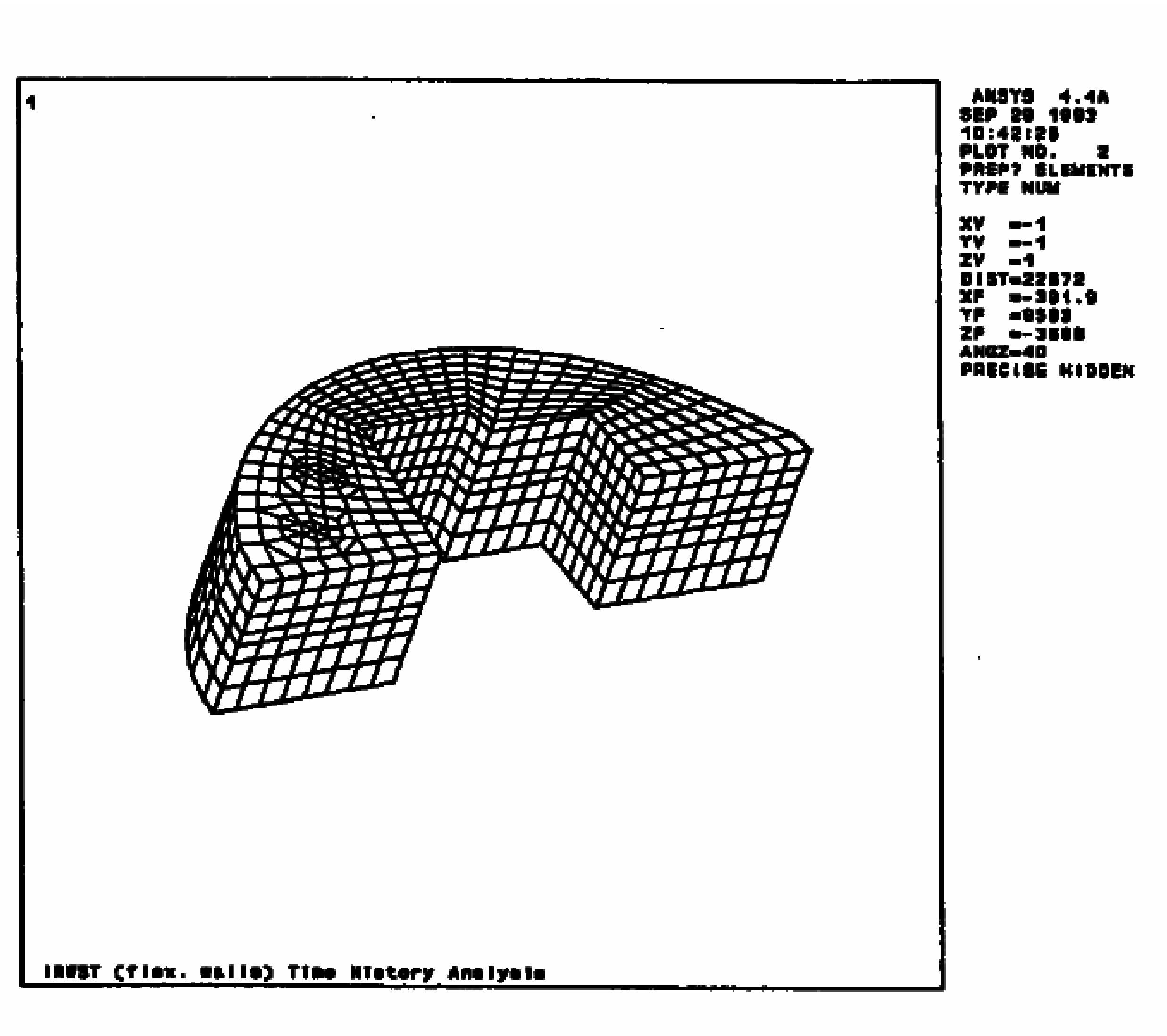


Figure 3.8.3-11

**IRWST Fluid Structure Finite Element Model
Fluid Model**

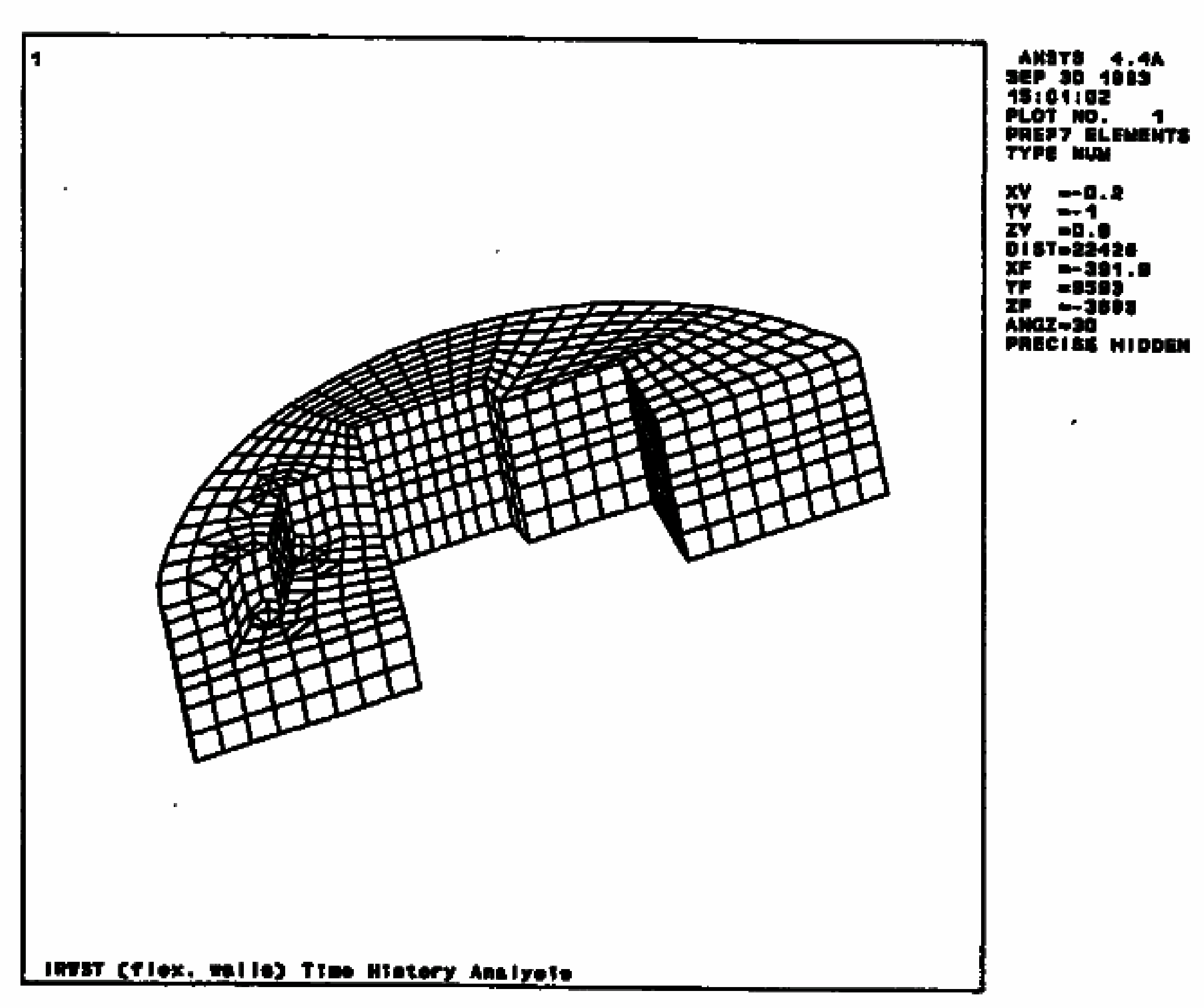
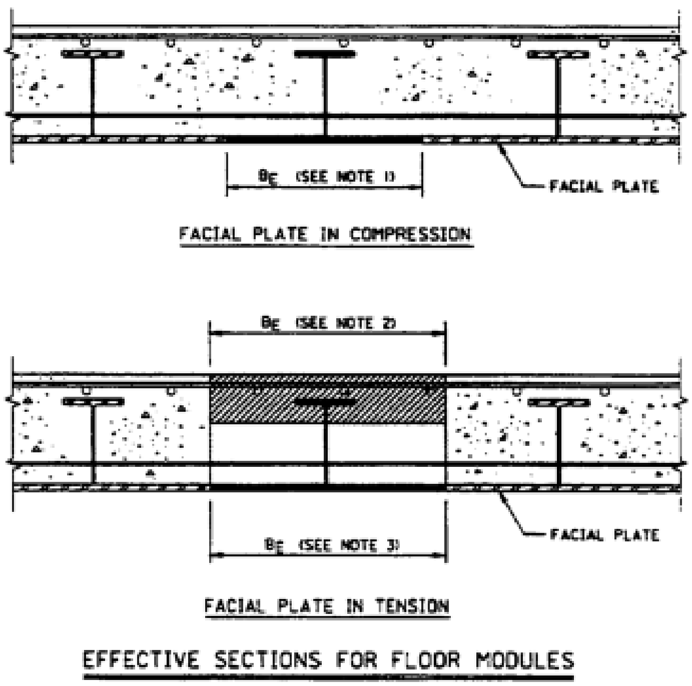


Figure 3.8.3-12

IRWST Fluid Structure Finite Element Model
Sparger Region Detail



NOTES:

1. FOR FACIAL PLATE IN COMPRESSION, b_e, IS DETERMINED PER SECTION 3.8.3.5.4.2
2. EFFECTIVE WIDTH OF CONCRETE, b_e, IS DETERMINED PER SECTION Q 1.11.1 OF AISC N690.
3. FOR FACIAL PLATE IN TENSION, b_e, IS TAKEN TO BE ONE HALF OF THE DISTANCE TO THE ADJACENT BEAMS.

Figure 3.8.3-13

Effective Sections for Floor Modules

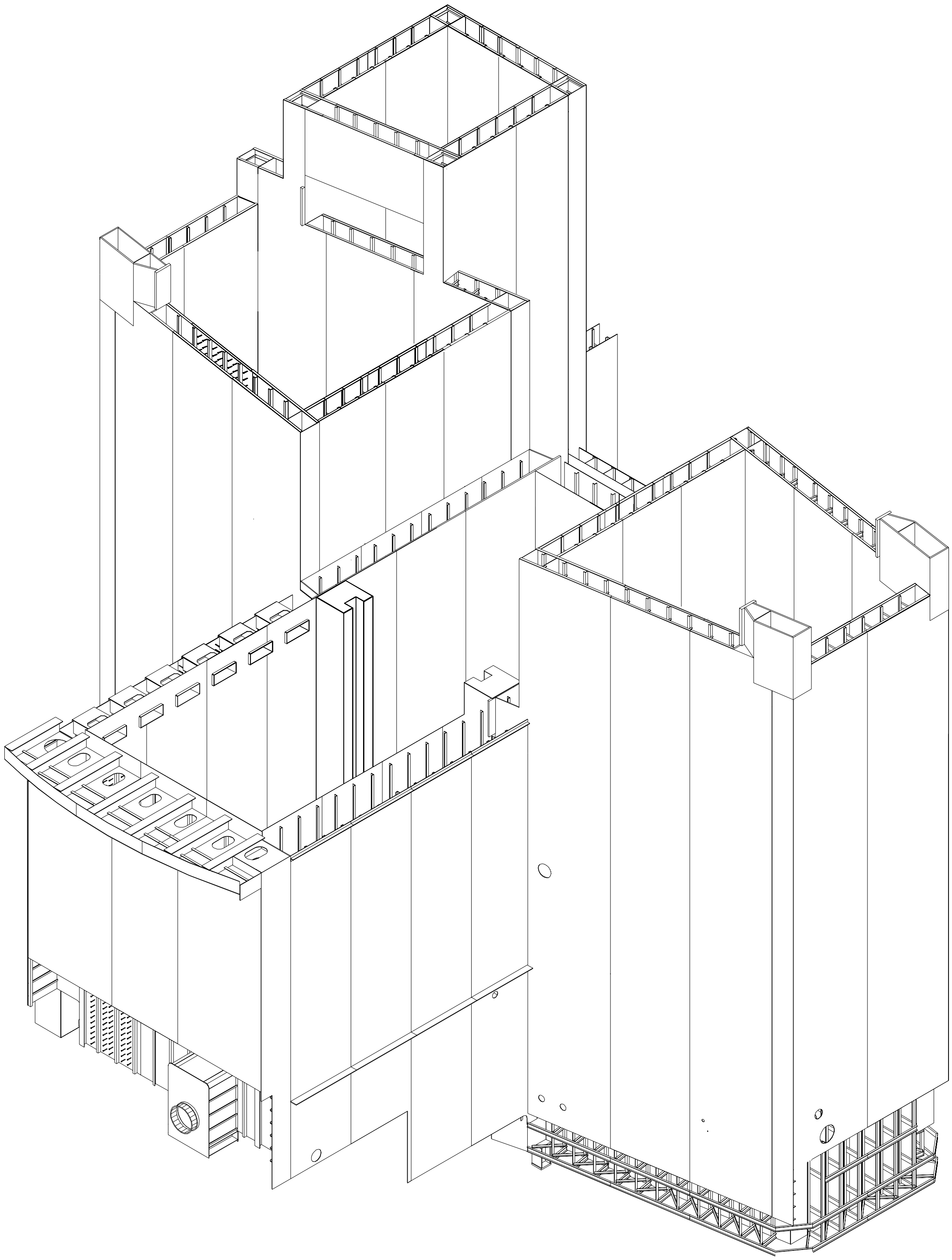


Figure 3.8.3-14 (Sheet 1 of 5)

[*CA-01 Module*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

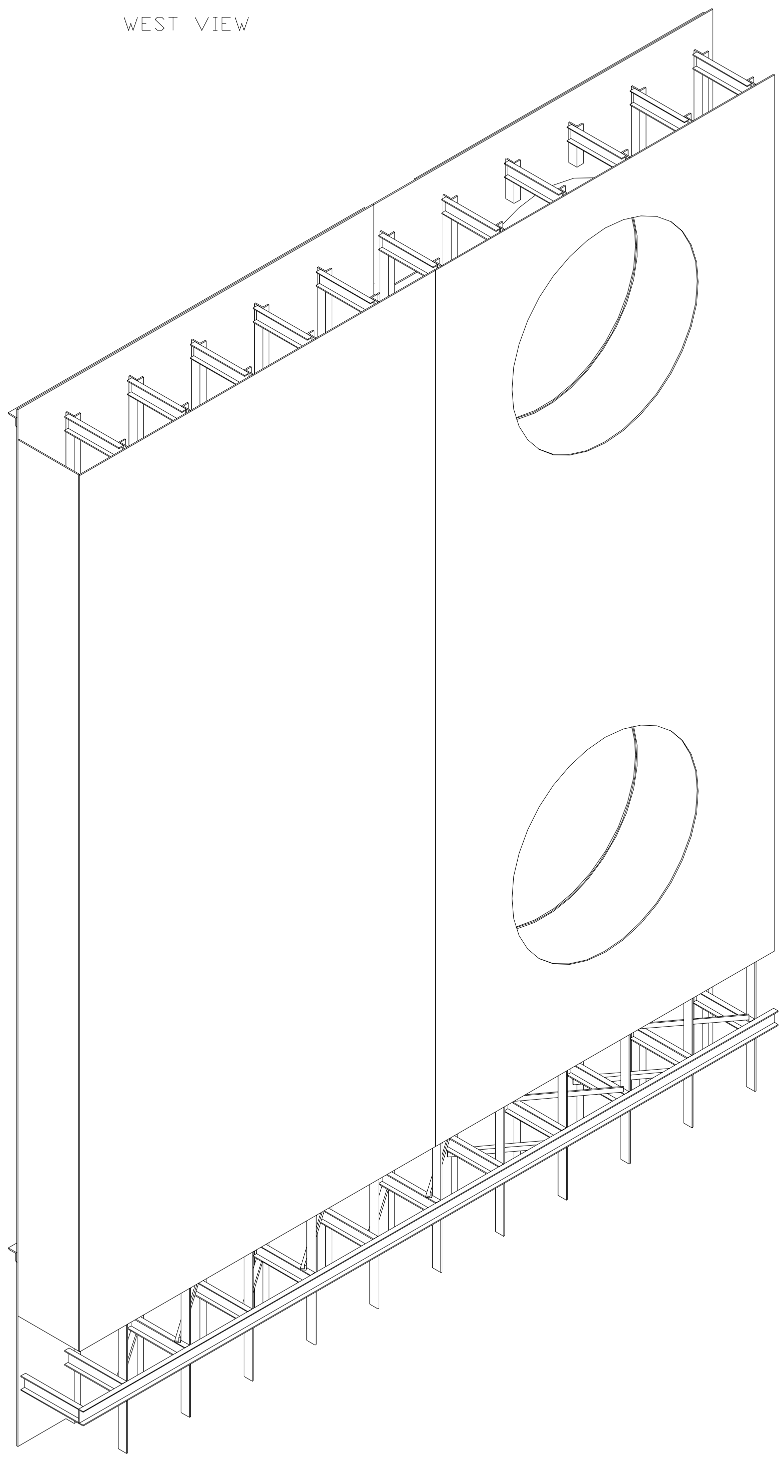


Figure 3.8.3-14 (Sheet 2 of 5)

[*CA-02 Module*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

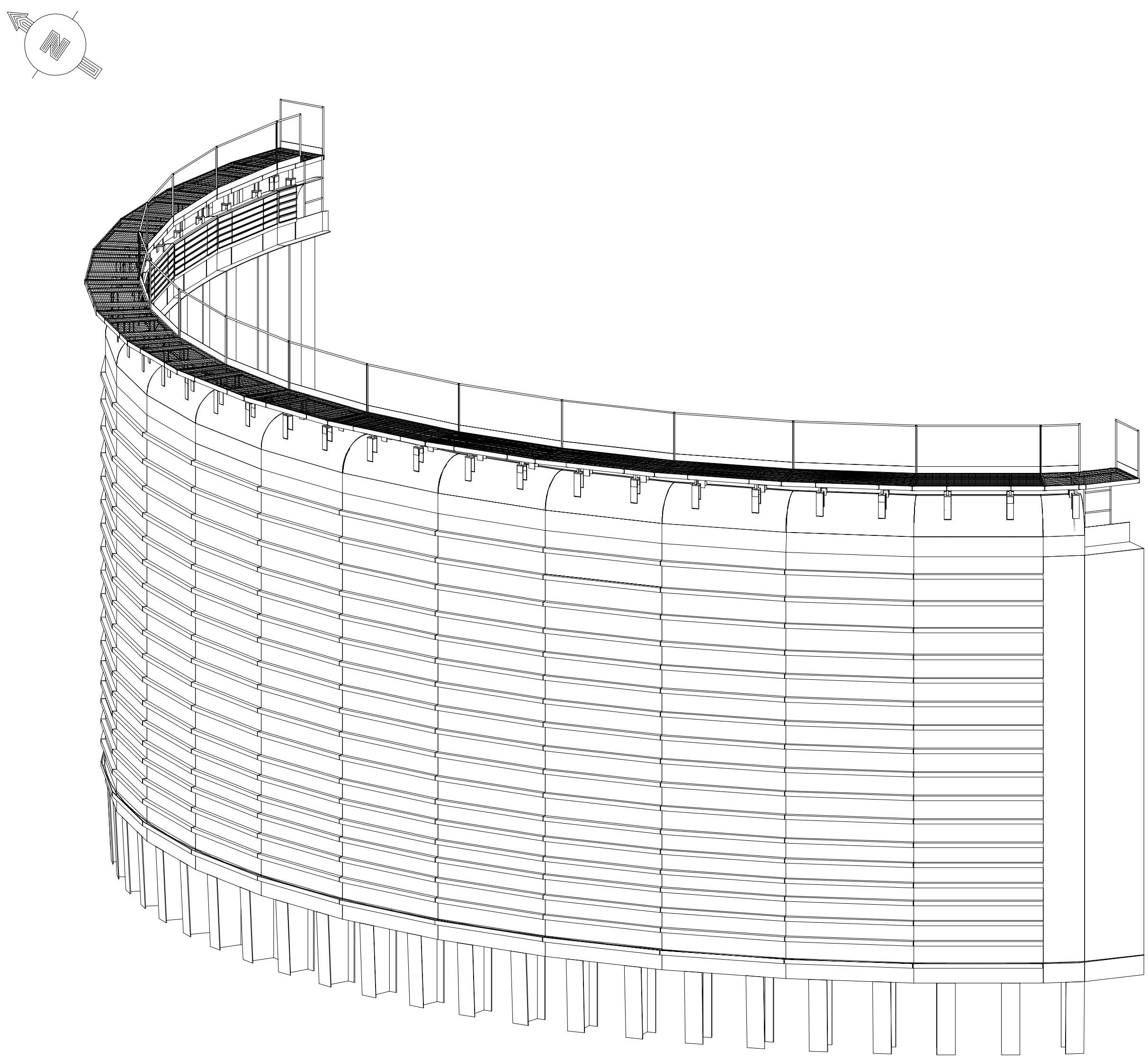


Figure 3.8.3-14 (Sheet 3 of 5)

[*CA-03 Module*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

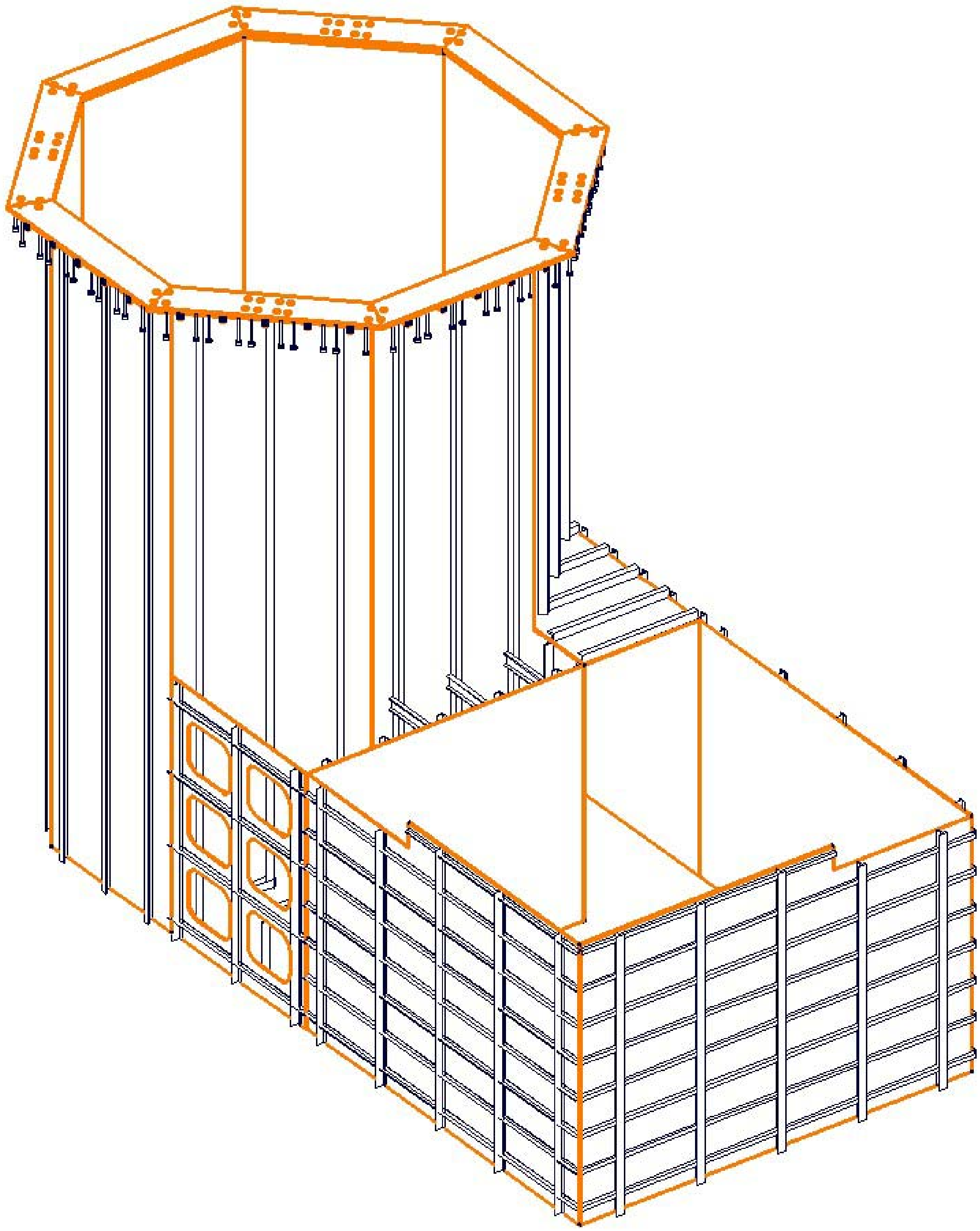


Figure 3.8.3-14 (Sheet 4 of 5)

[*CA-04 Structural Module*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

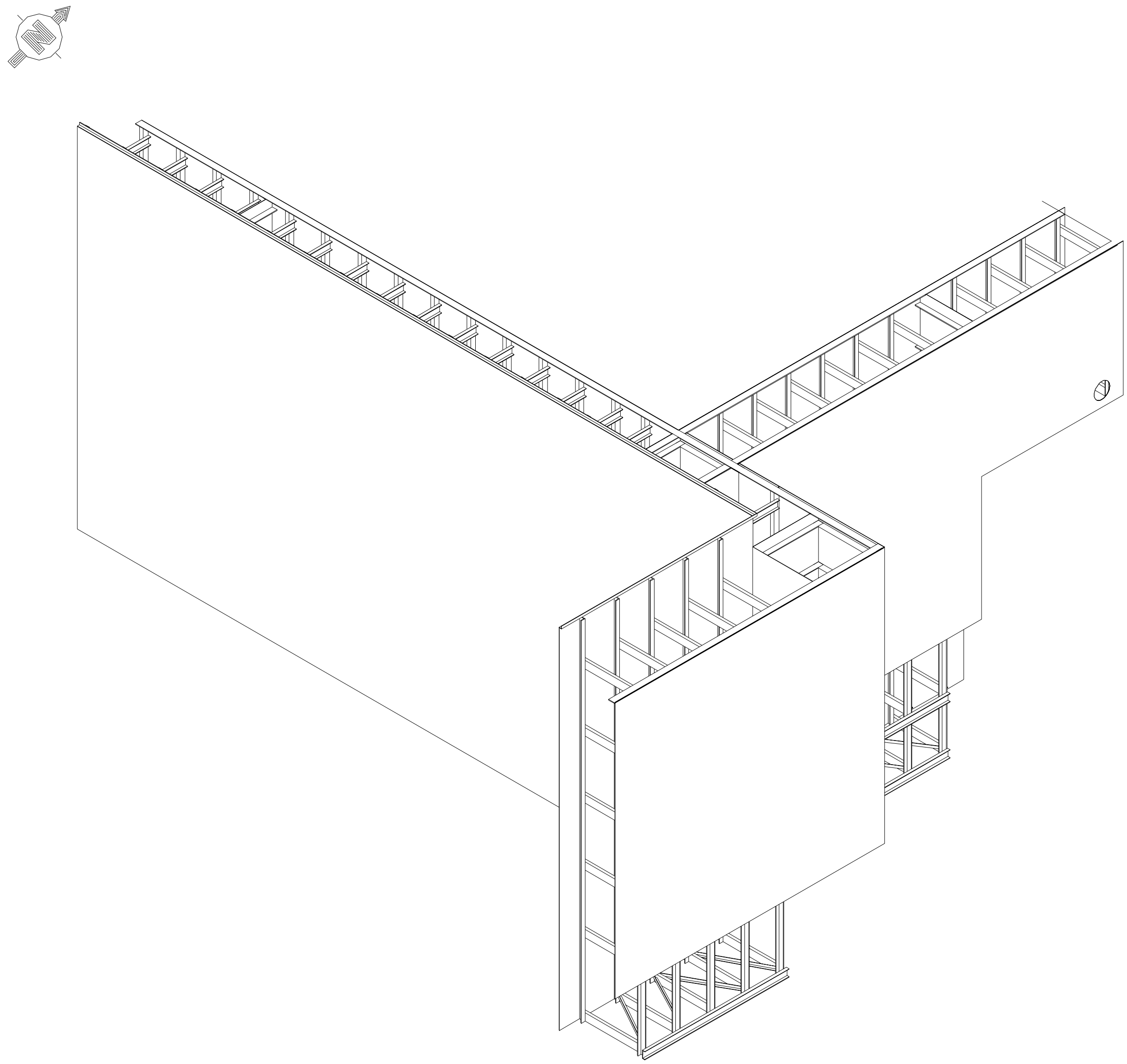


Figure 3.8.3-14 (Sheet 5 of 5)

[*CA-05 Module*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

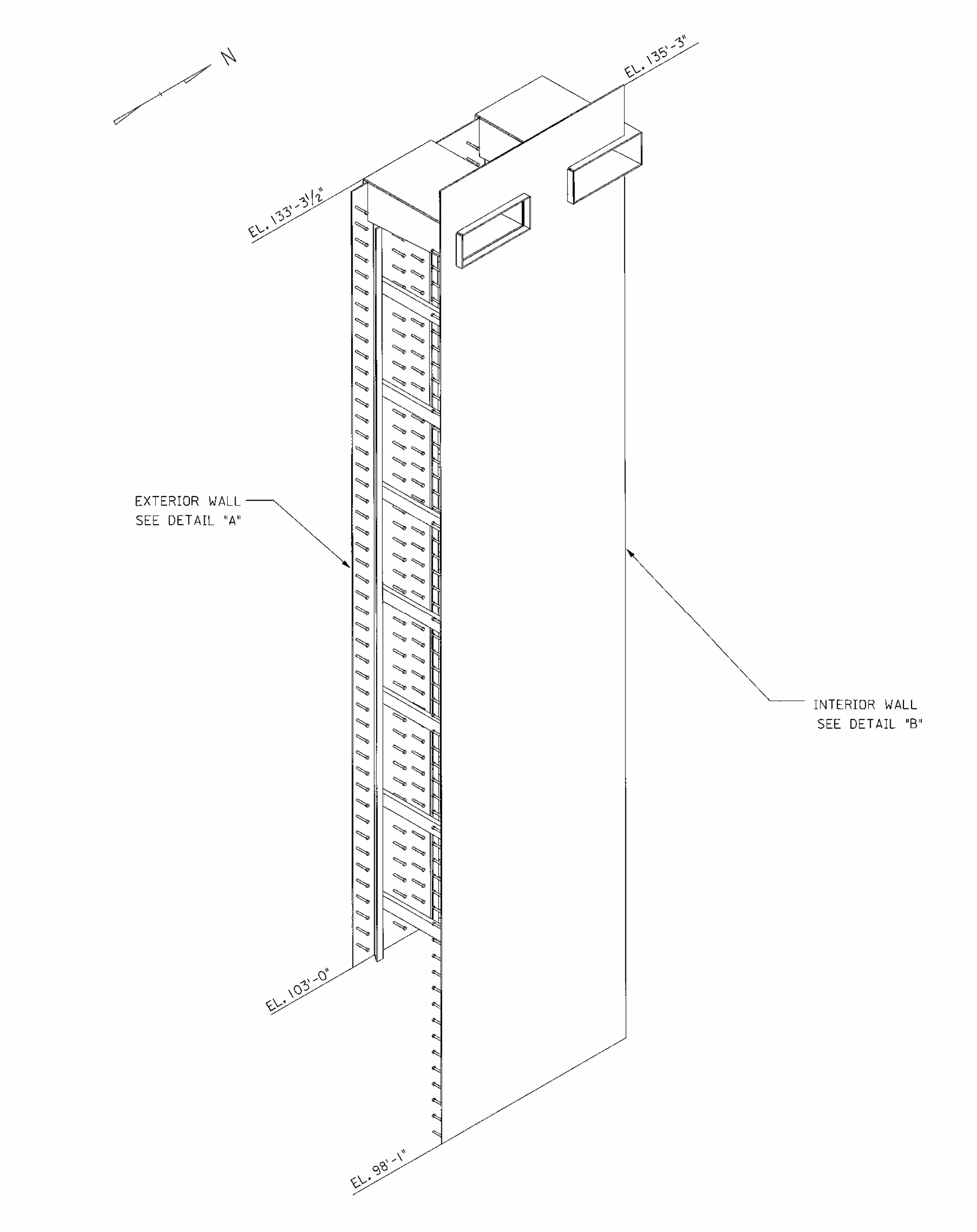


Figure 3.8.3-15 (Sheet 1 of 2)

[*Typical Submodule*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

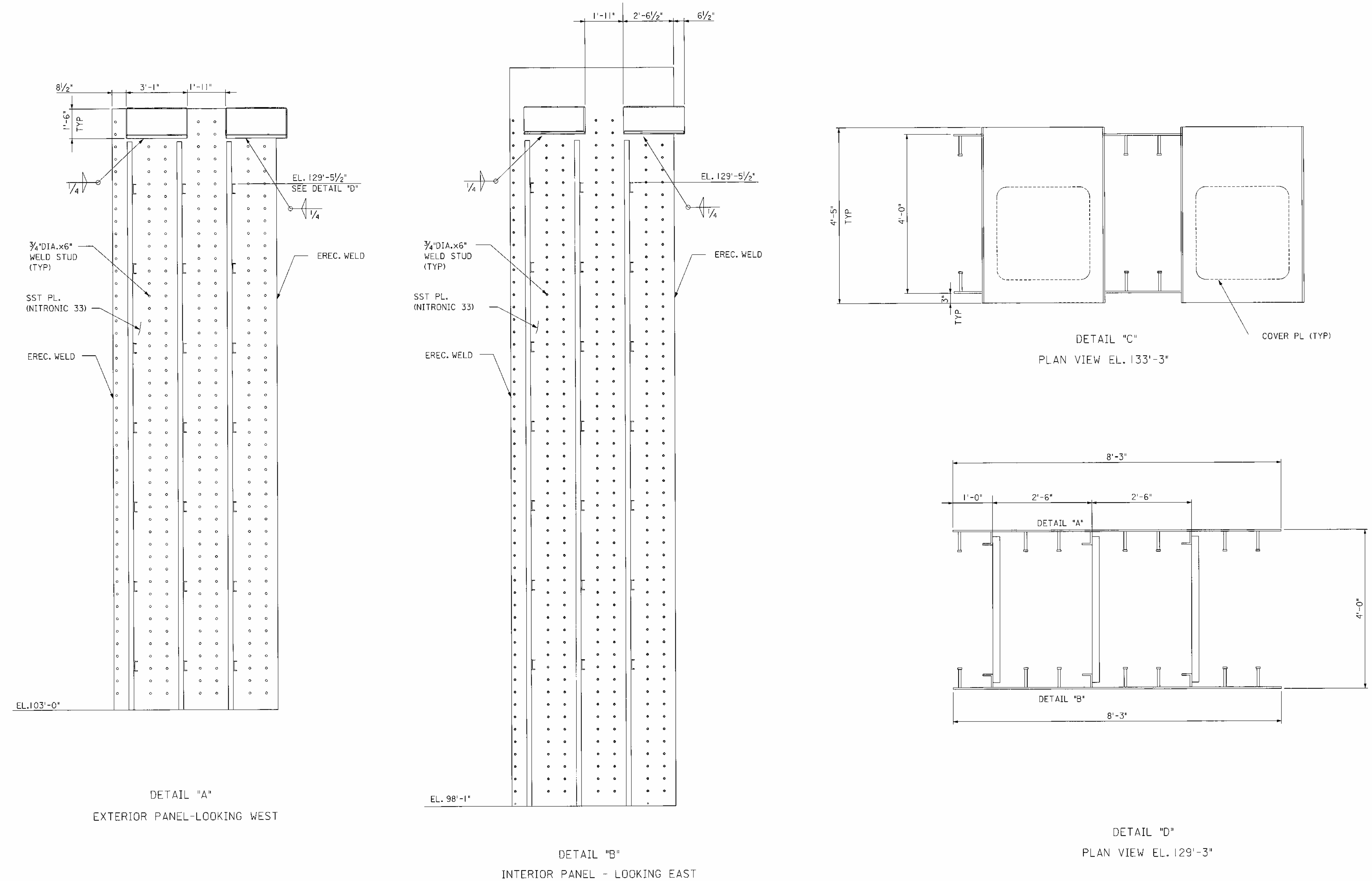


Figure 3.8.3-15 (Sheet 2 of 2)

[Typical Submodule]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

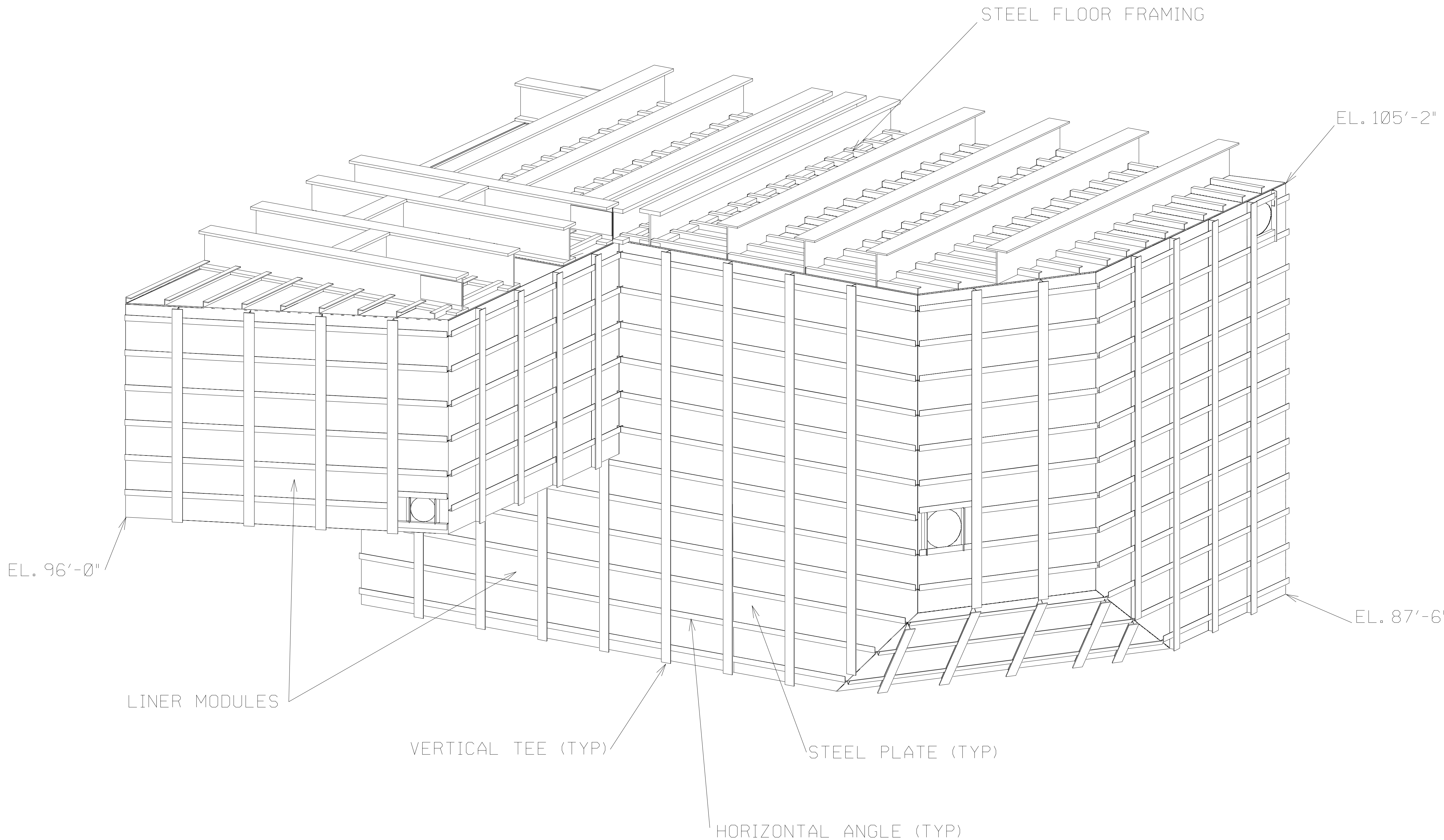


Figure 3.8.3-16

Typical Liner Modules

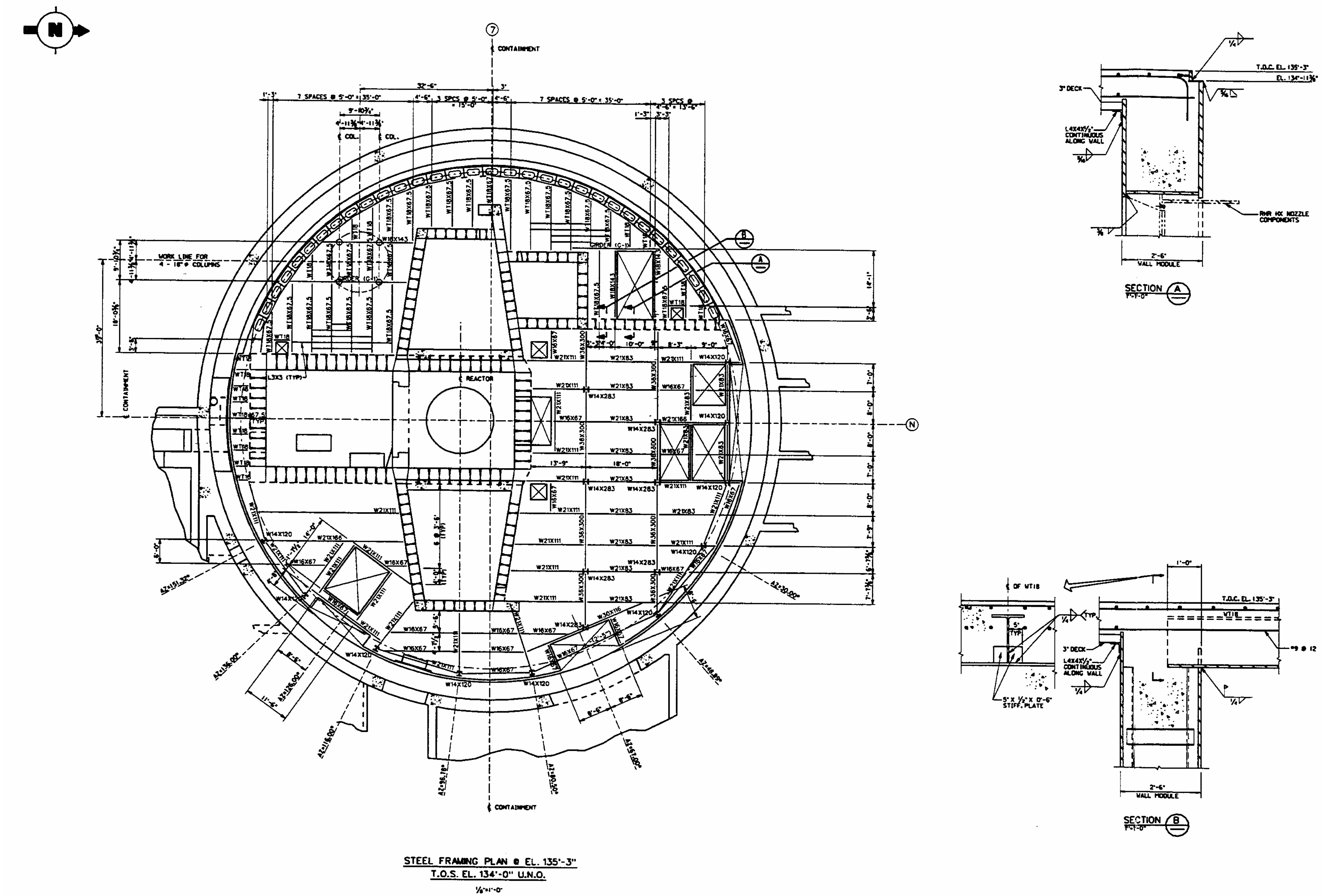


Figure 3.8.3-17 (Sheet 1 of 2)

[*Structural Modules – Typical Design Details*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

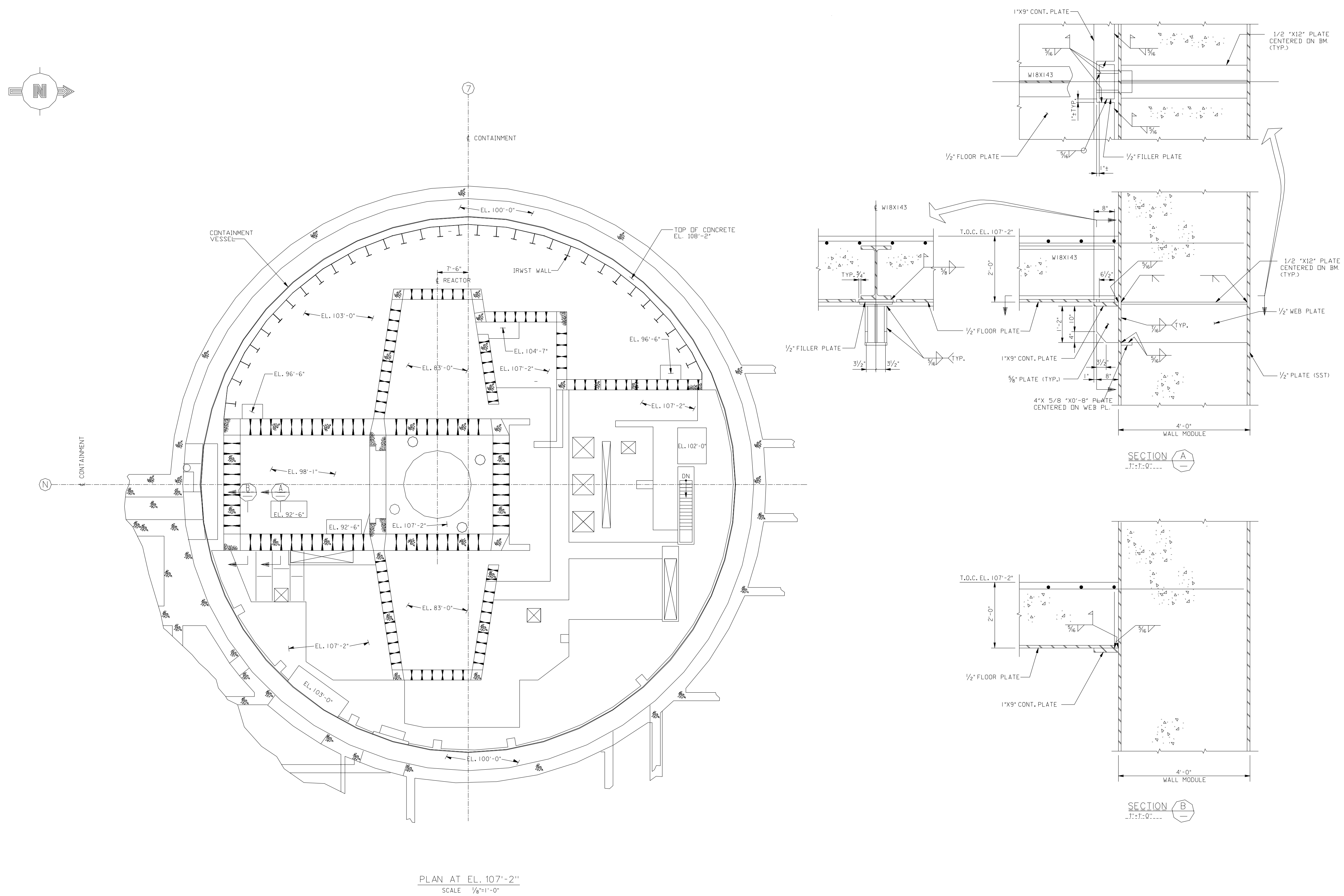


Figure 3.8.3-17 (Sheet 2 of 2)

[Structural Modules – Typical Design Details]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

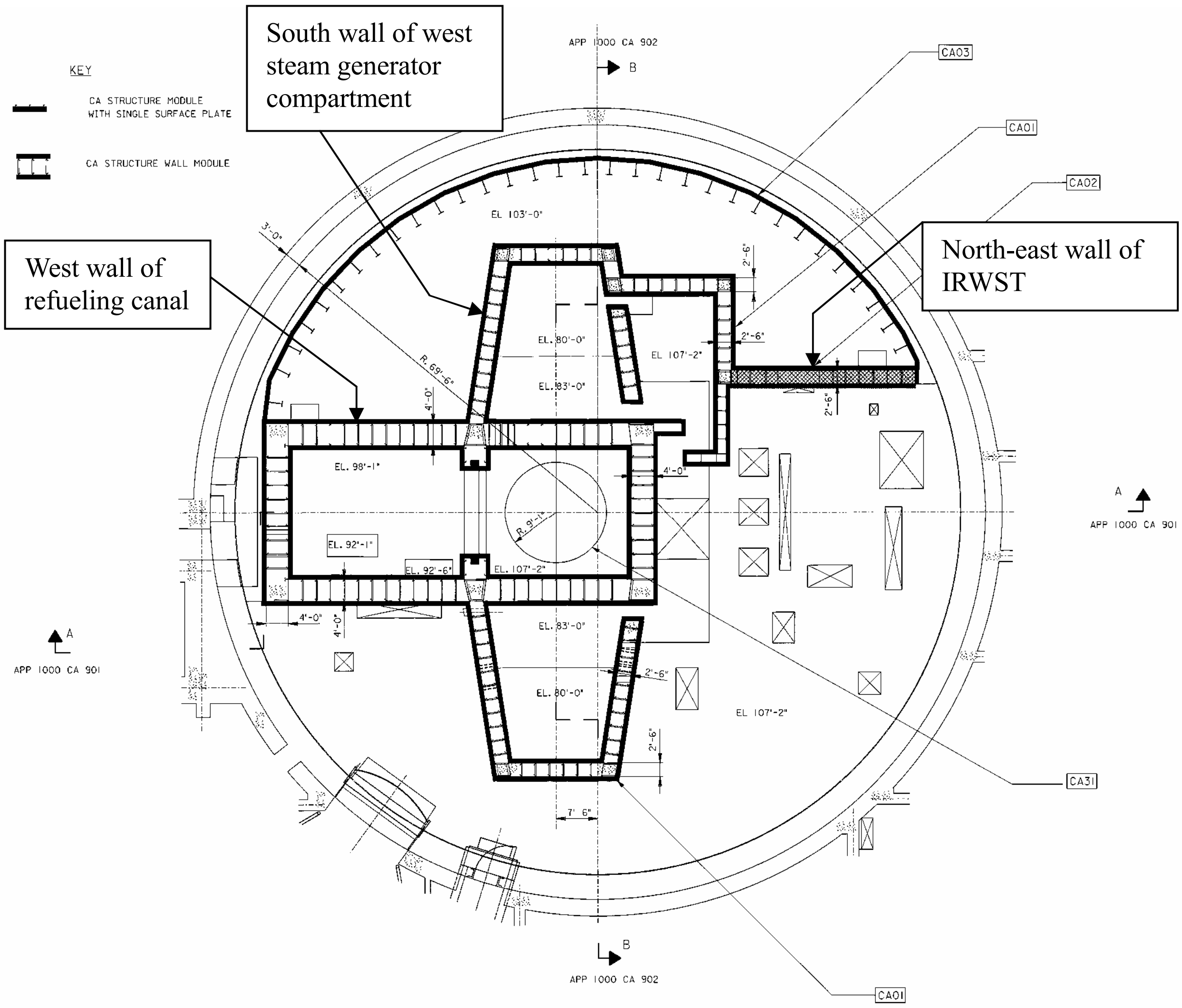


Figure 3.8.3-18

[*Location of Structural Wall Modules*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

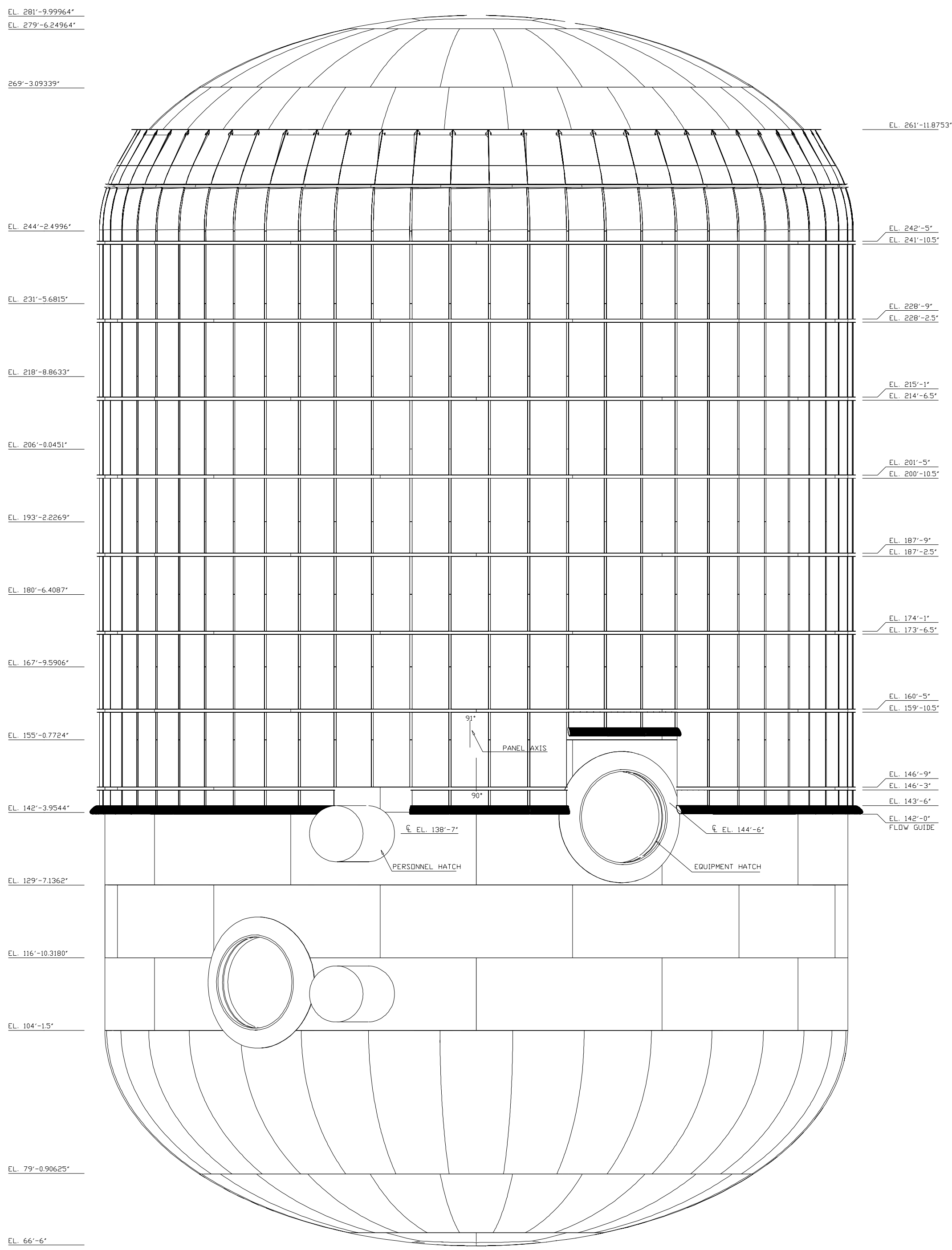


Figure 3.8.4-1 (Sheet 1 of 4)

Containment Air Baffle
General Arrangement

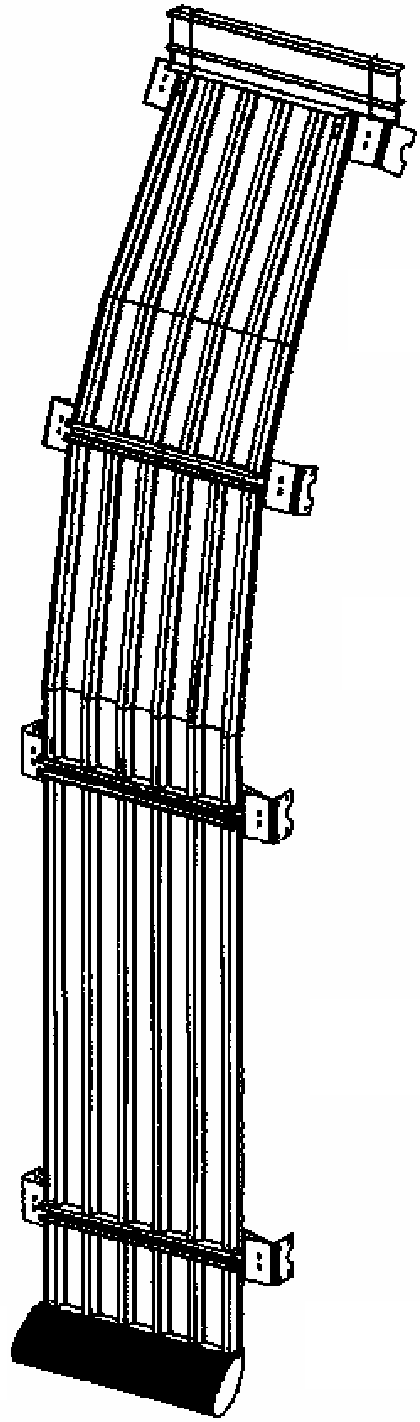


Figure 3.8.4-1 (Sheet 2 of 4)

**Containment Air Baffle
Panel Types**

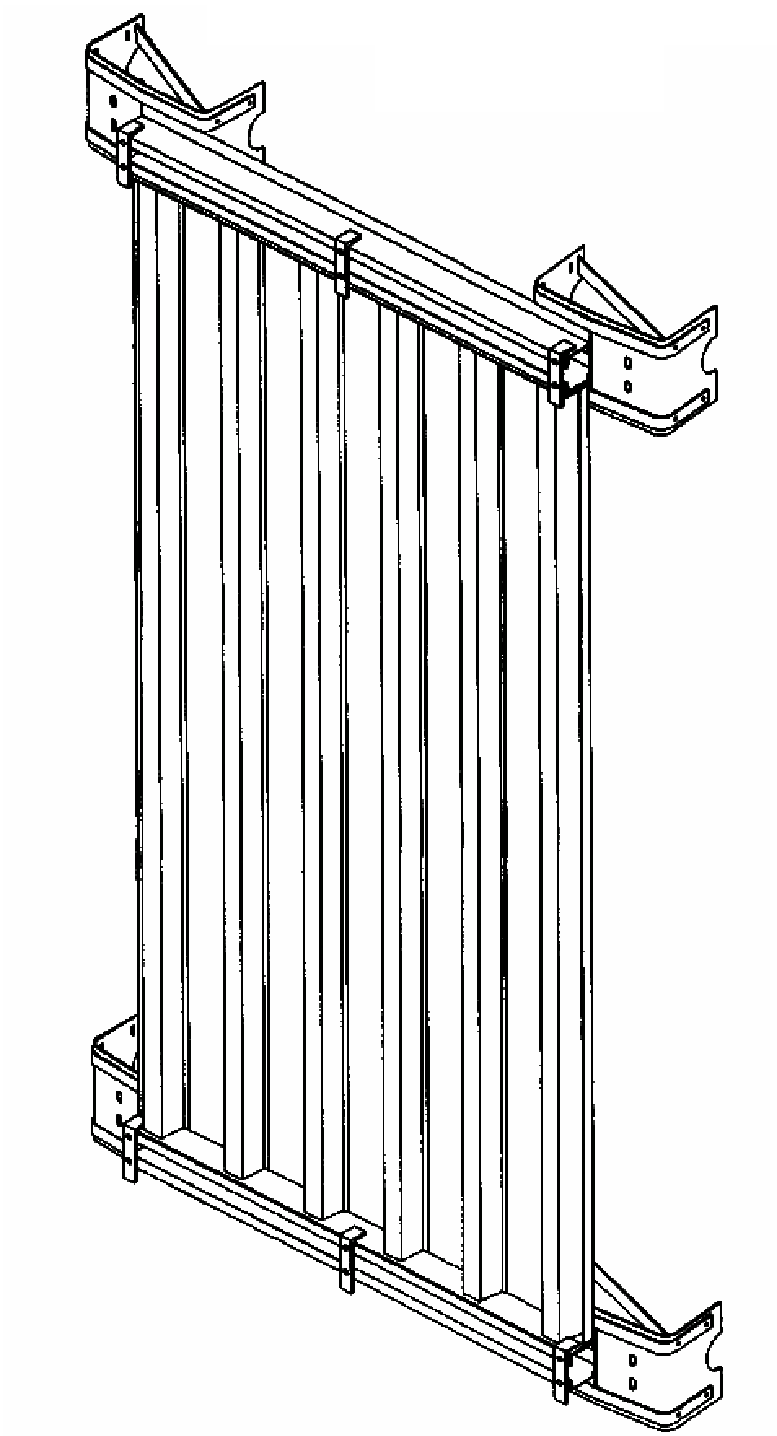


Figure 3.8.4-1 (Sheet 3 of 4)

Containment Air Baffle
Typical Panel on Cylinder

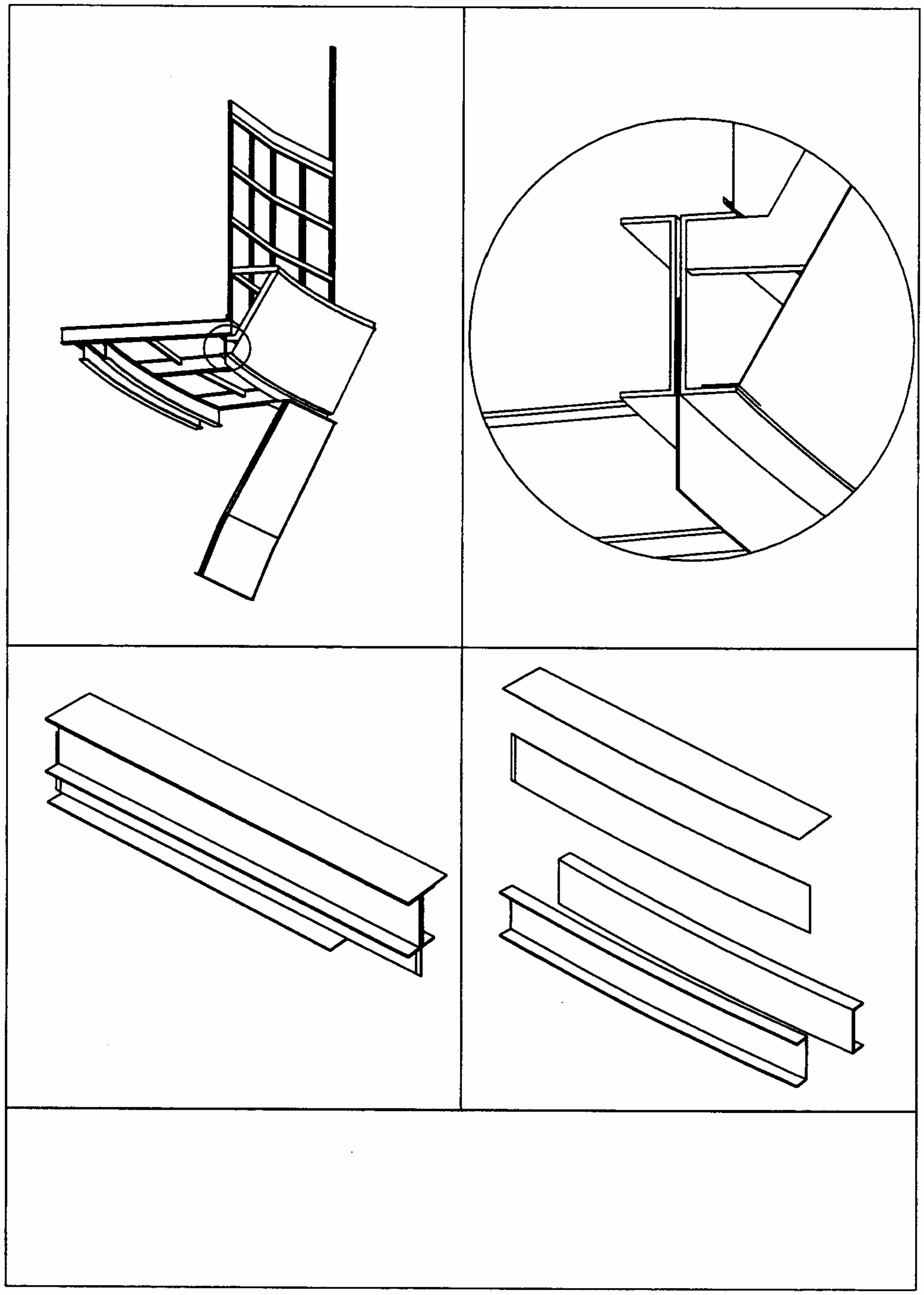
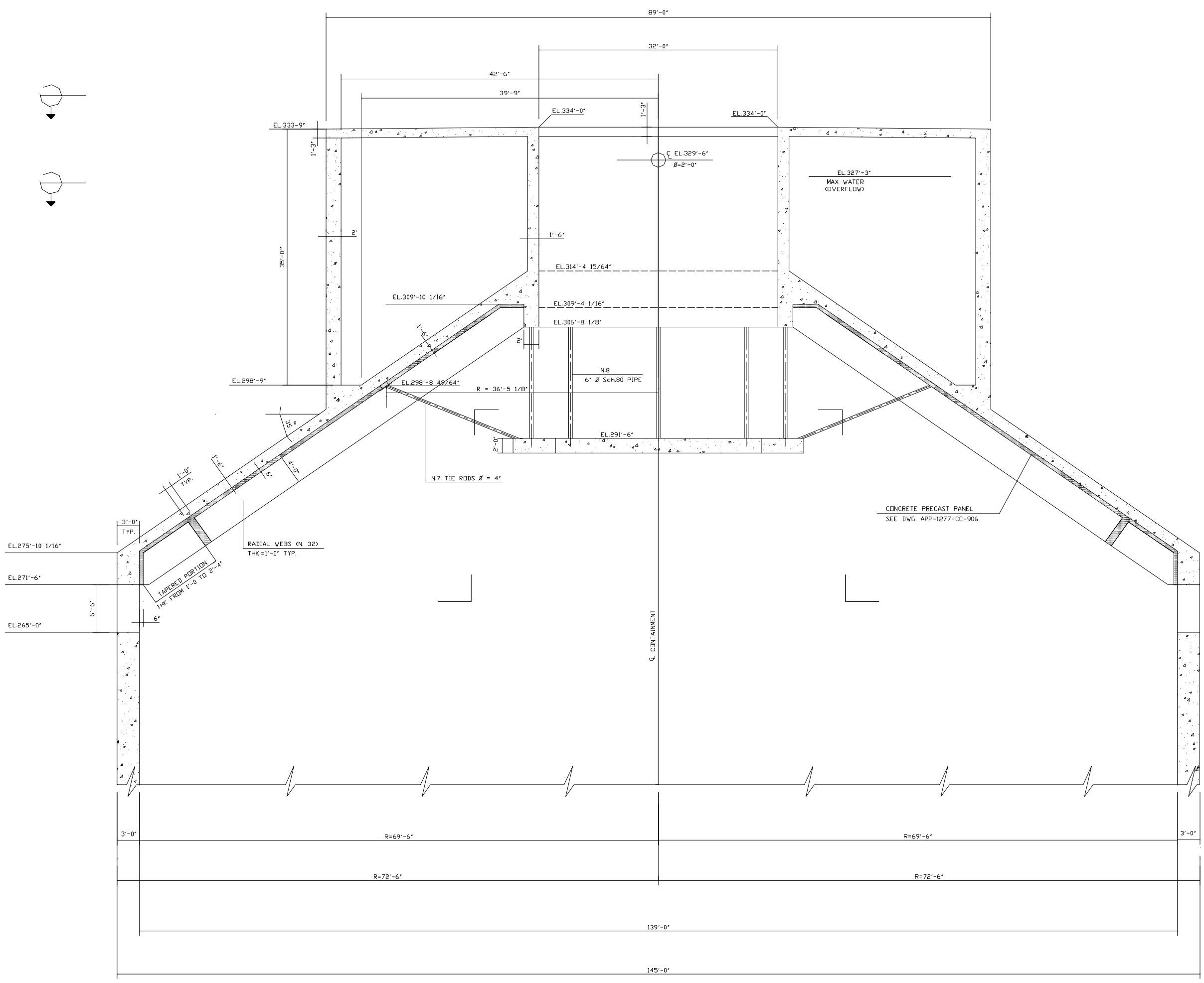


Figure 3.8.4-1 (Sheet 4 of 4)

**Containment Air Baffle
Sliding Plate**

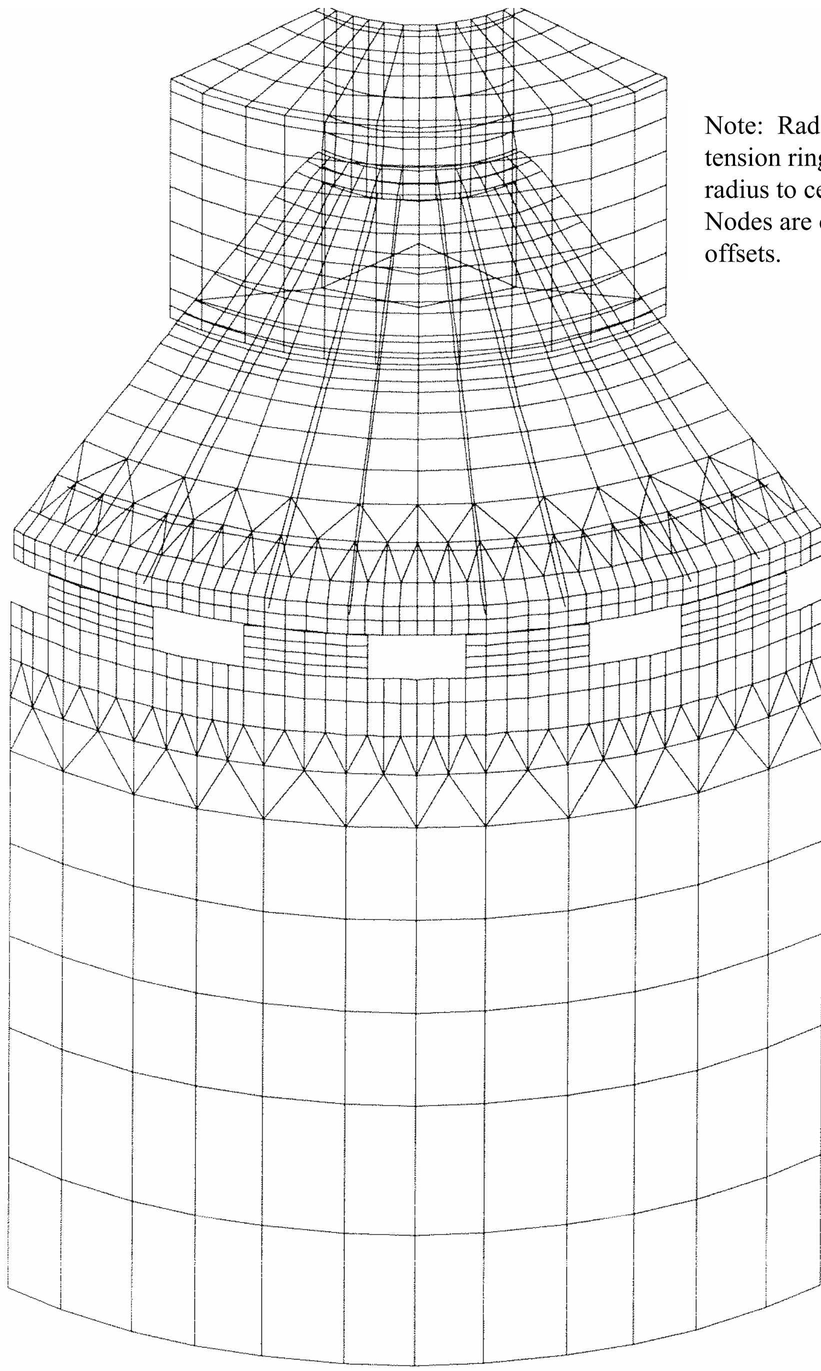


SECTION A-A

Figure 3.8.4-2

[*Passive Containment Cooling Tank*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.



Note: Radius to center line of tension ring is 3 inches less than radius to center line of columns. Nodes are connected by rigid offsets.

Figure 3.8.4-3

Finite Element Model of Shield Building Roof

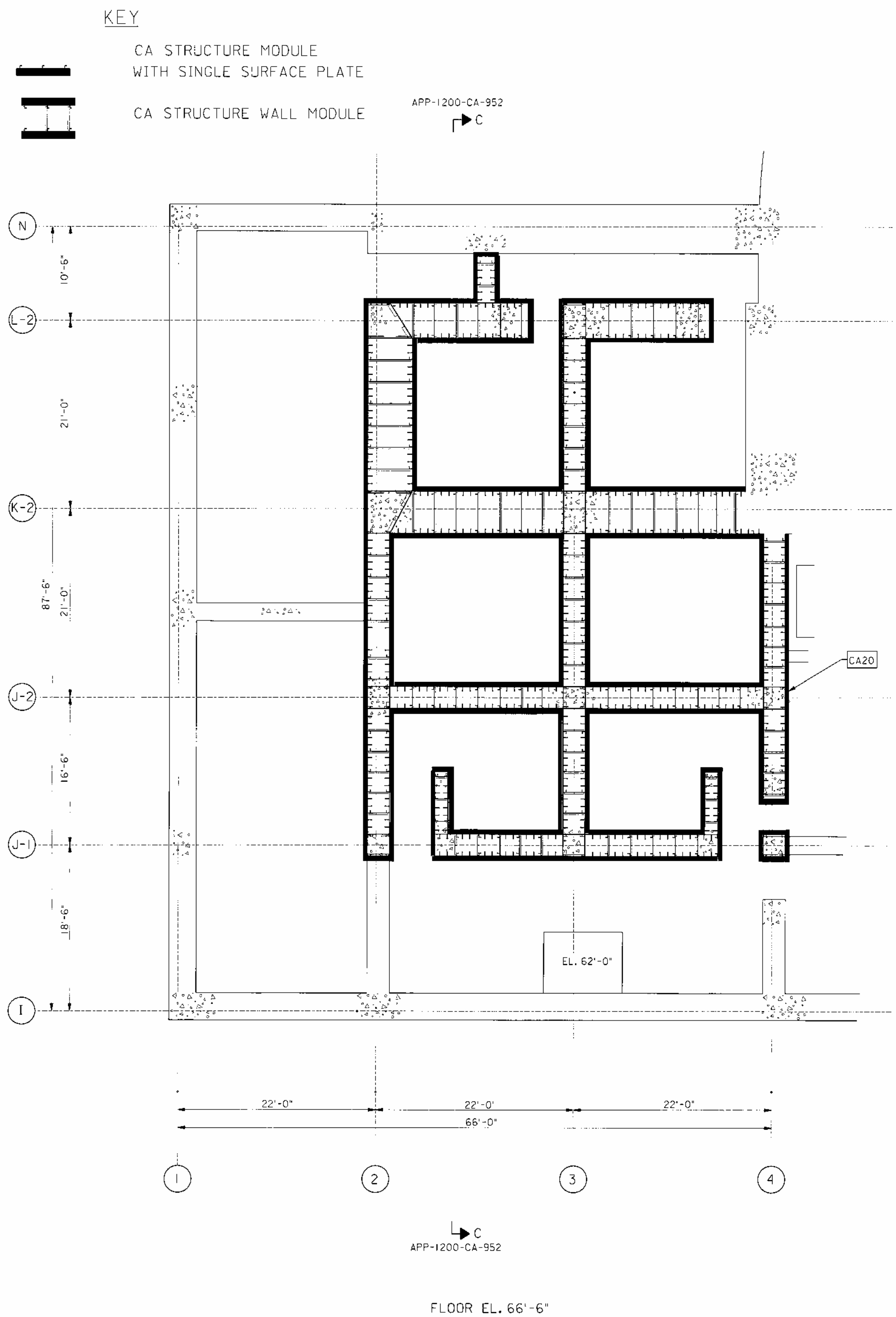


Figure 3.8.4-4 (Sheet 1 of 5)

[*Structural Modules in Auxiliary Building*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

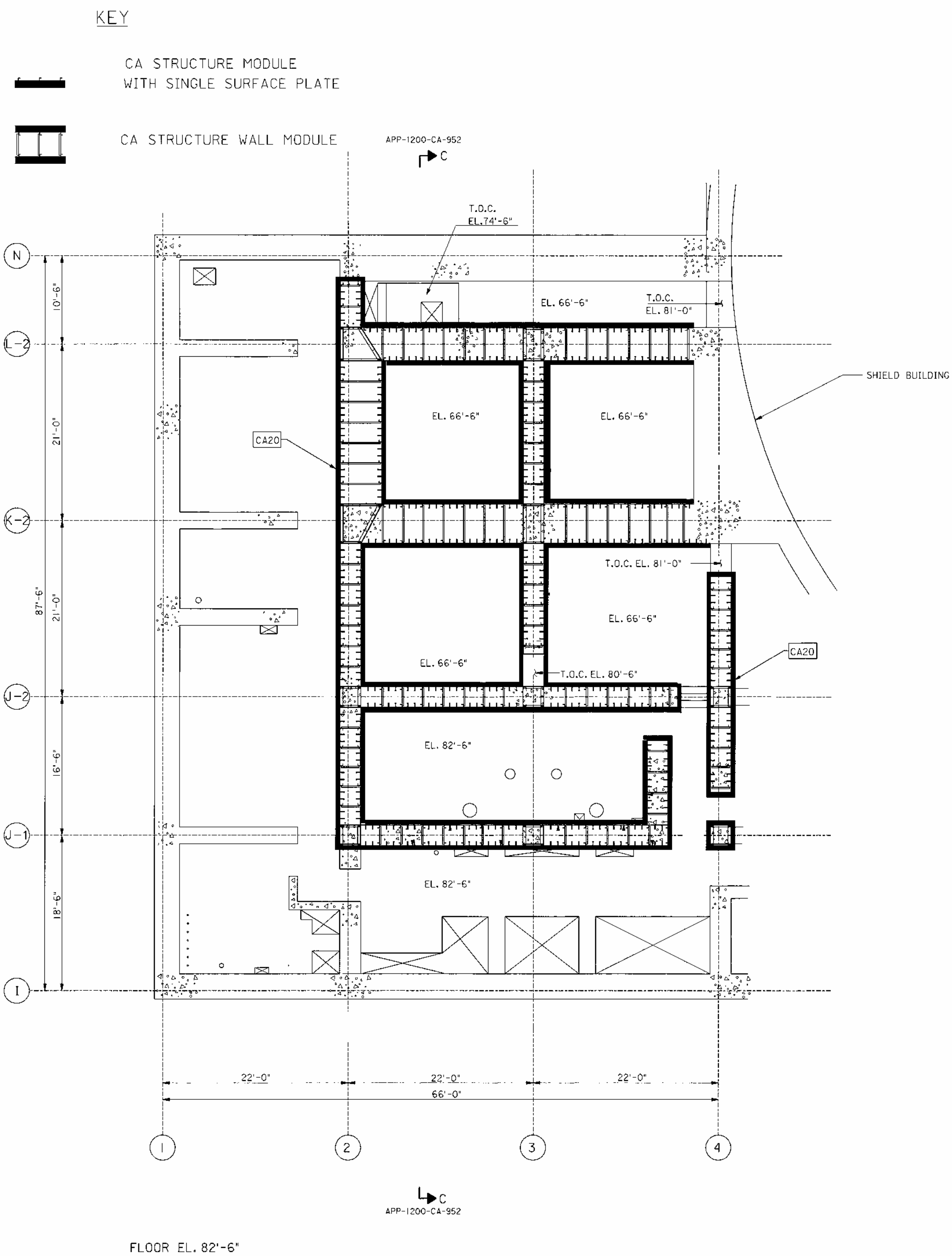


Figure 3.8.4-4 (Sheet 2 of 5)

[*Structural Modules in Auxiliary Building*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

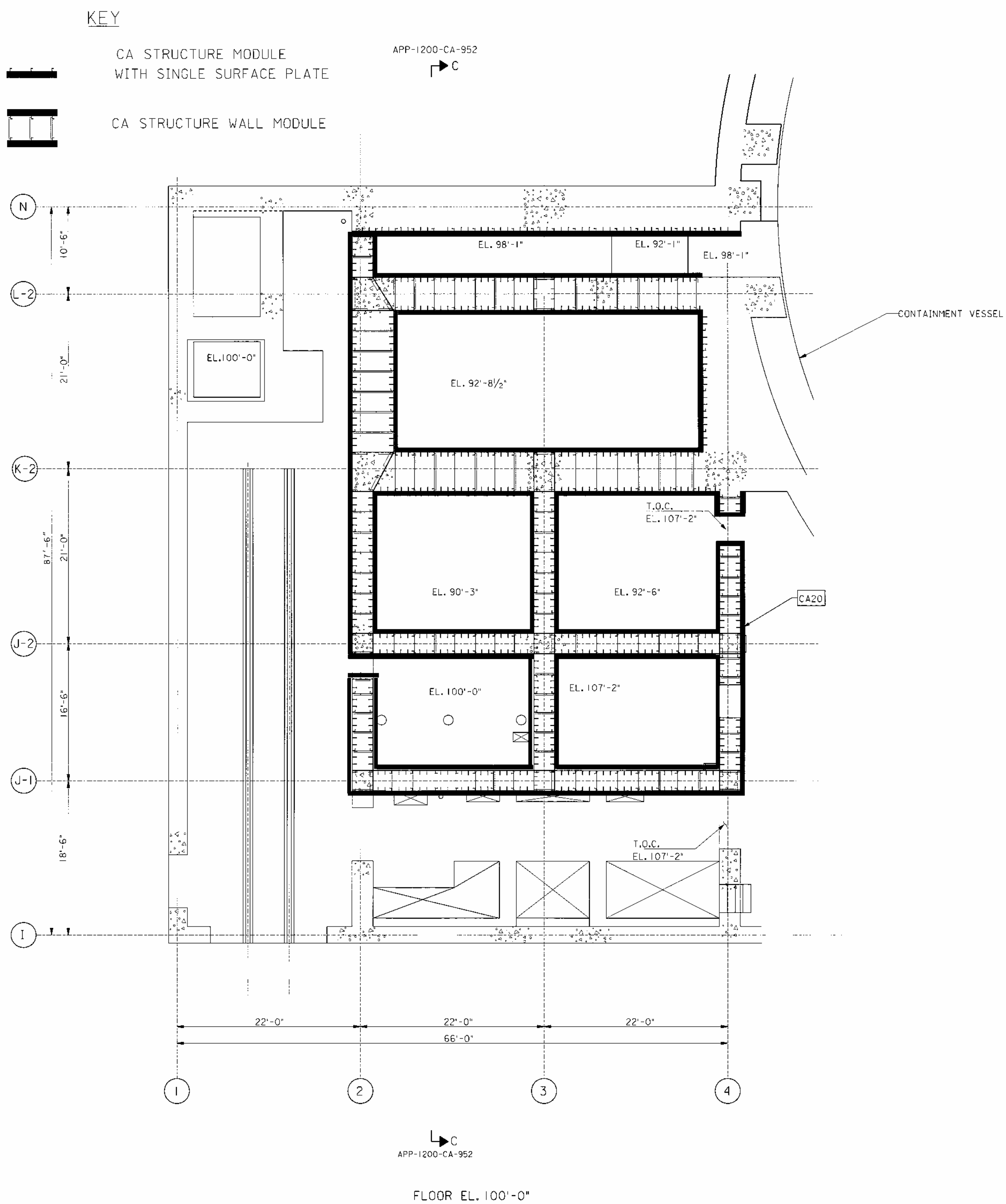


Figure 3.8.4-4 (Sheet 3 of 5)

[*Structural Modules in Auxiliary Building*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

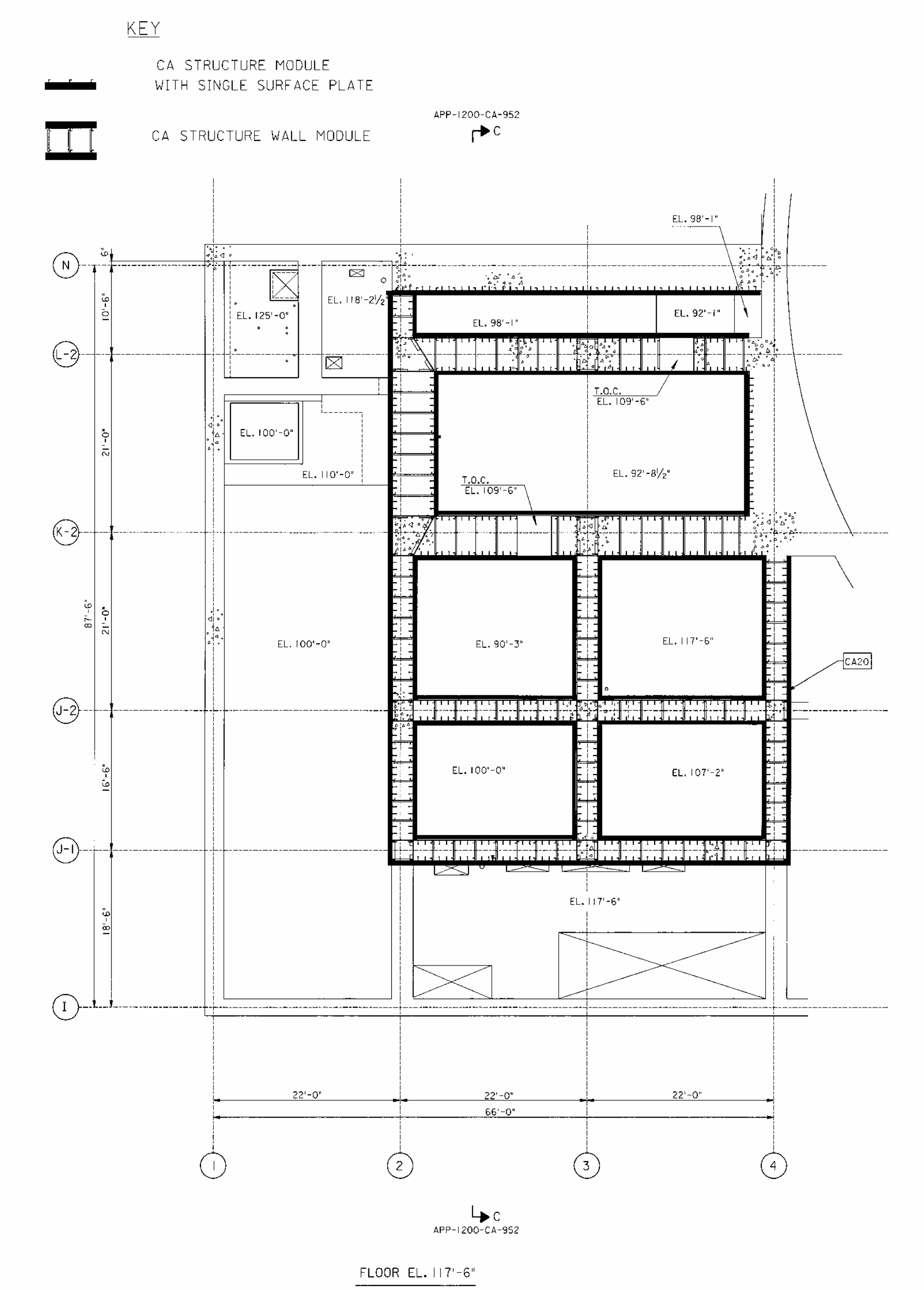


Figure 3.8.4-4 (Sheet 4 of 5)

[*Structural Modules in Auxiliary Building*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

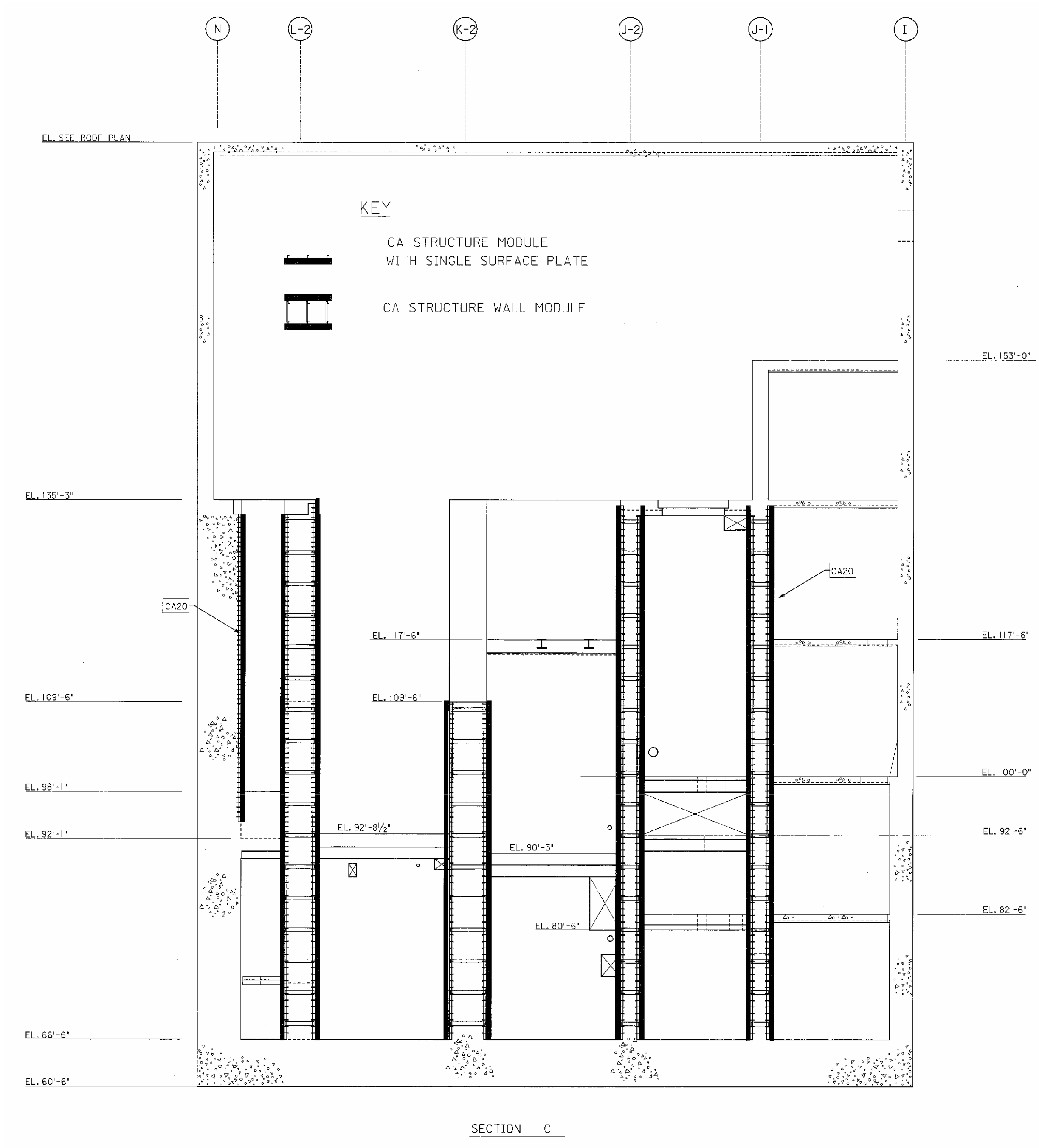


Figure 3.8.4-4 (Sheet 5 of 5)

[*Structural Modules in Auxiliary Building*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

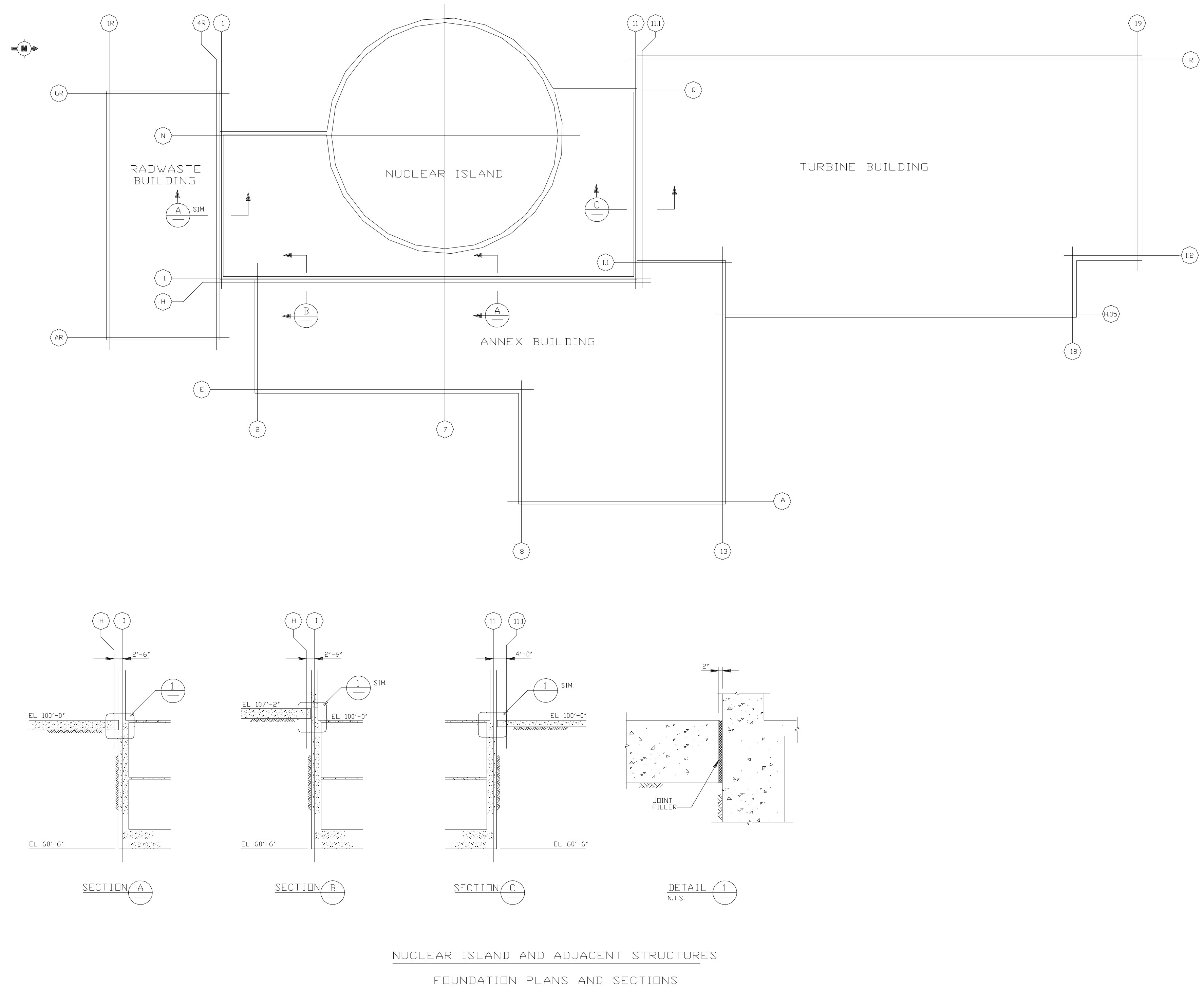


Figure 3.8.5-1

Foundation Plan

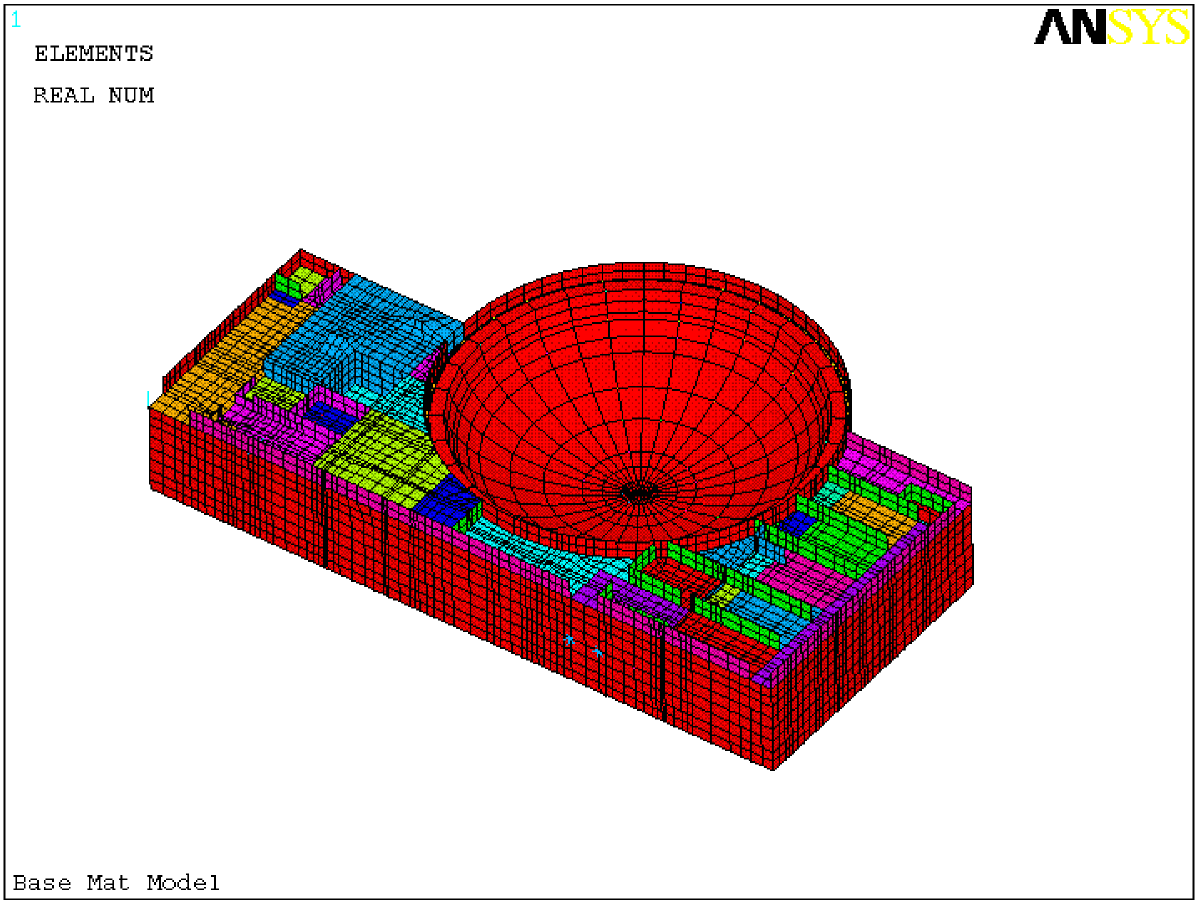


Figure 3.8.5-2 (Sheet 1 of 2)

Isometric View of Finite Element Model

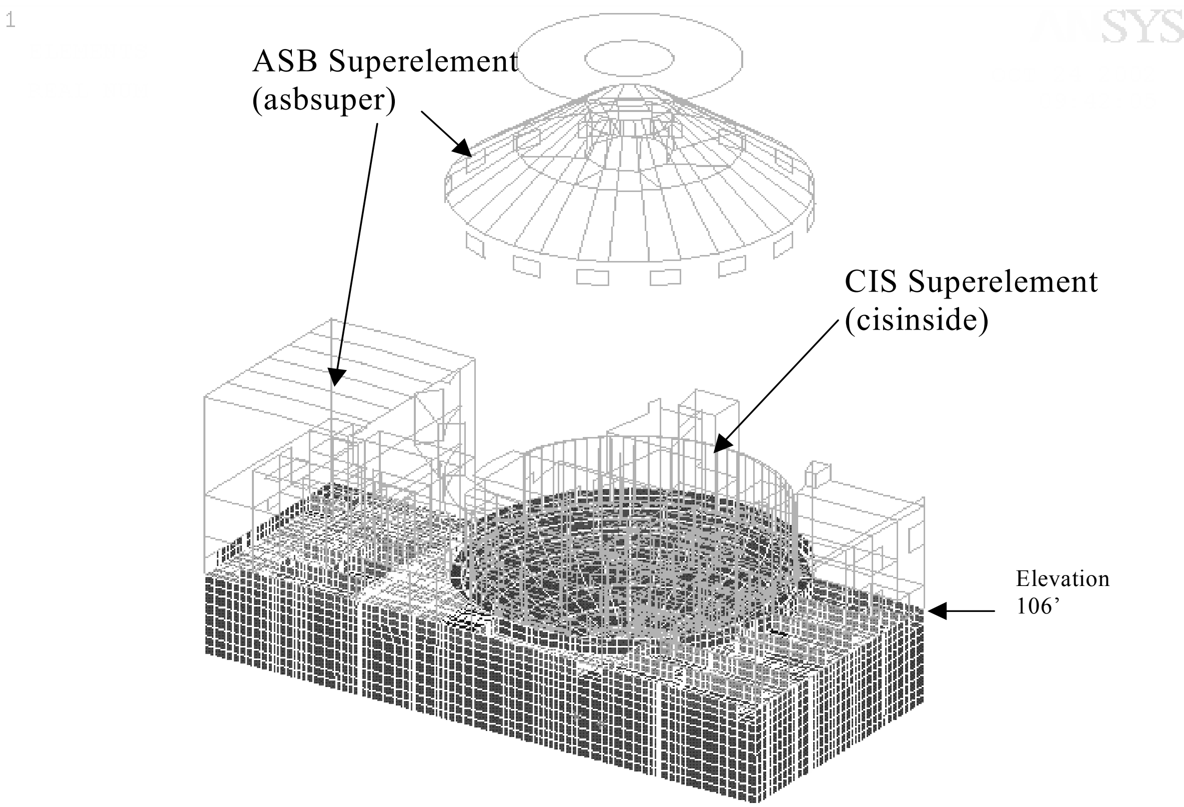
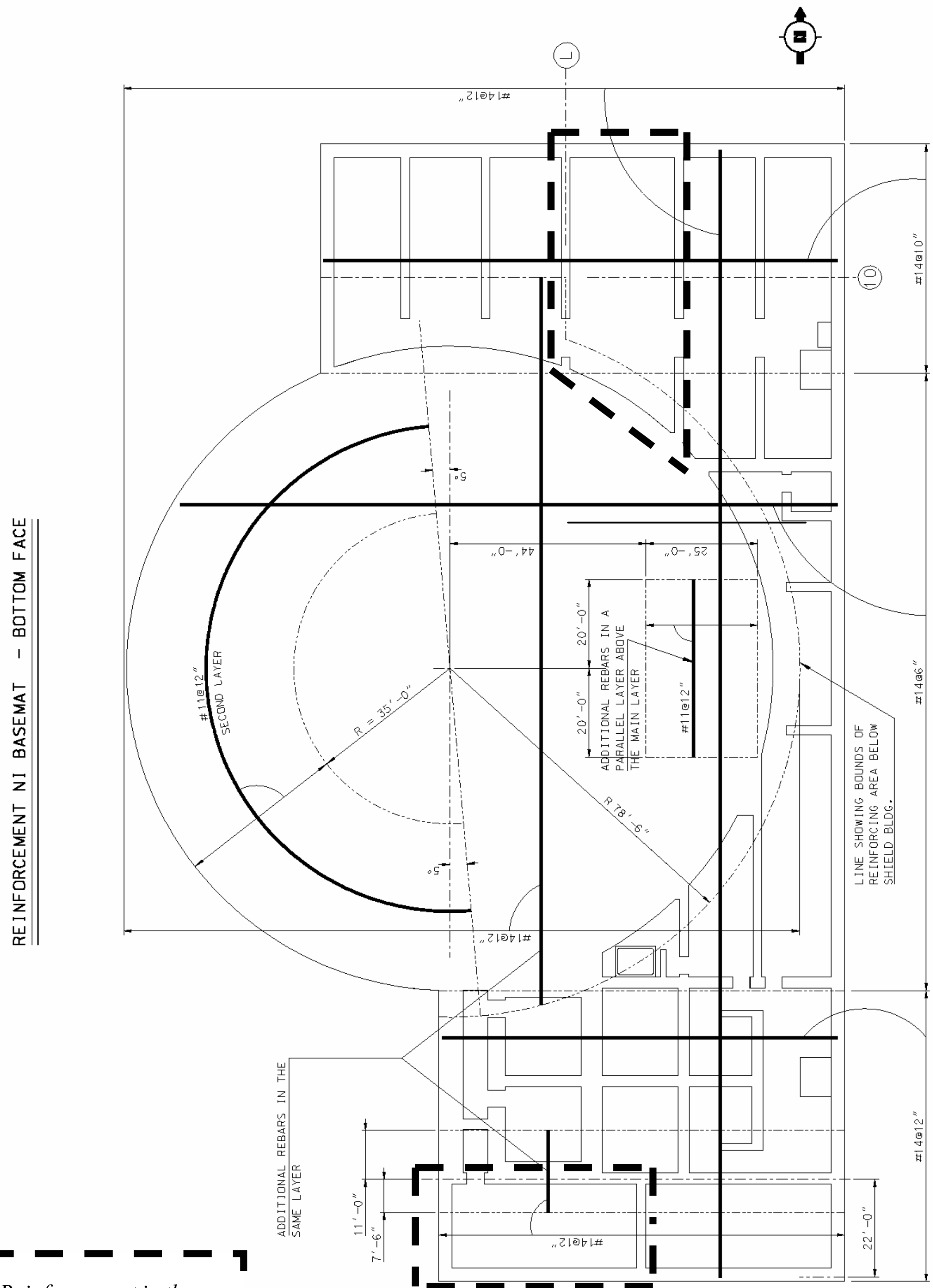


Figure 3.8.5-2 (Sheet 2 of 2)

Isometric View of Finite Element Model Including Superelements

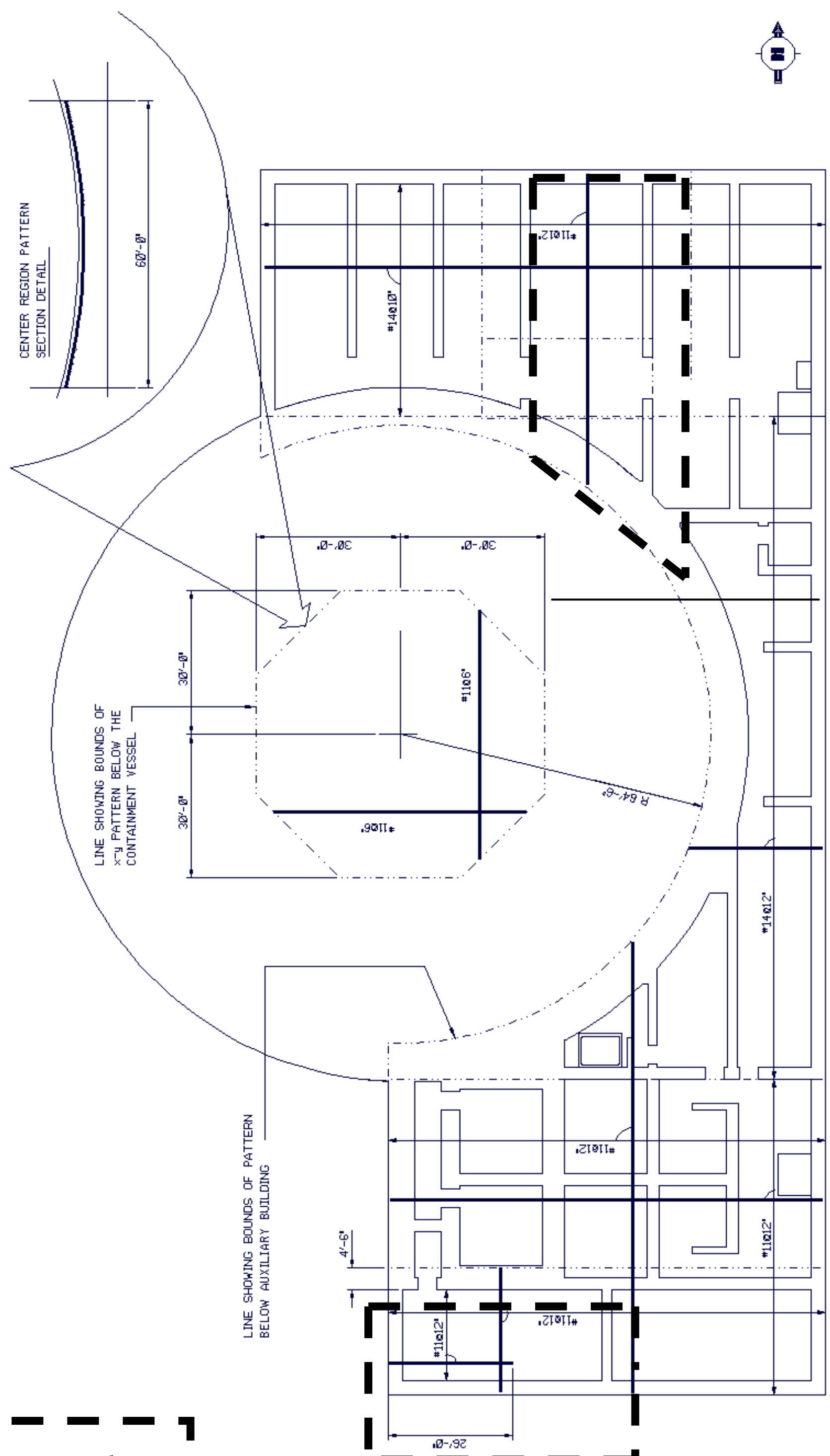


[*Reinforcement in these regions is given in Table 3.8.5-3*]*

Figure 3.8.5-3 (Sheet 1 of 5)

Basemat Reinforcement – Bottom Face

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.



[*Reinforcement in these regions is given in Table 3.8.5-3*]*

Figure 3.8.5-3 (Sheet 2 of 5)

Basemat Reinforcement – Top Face

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

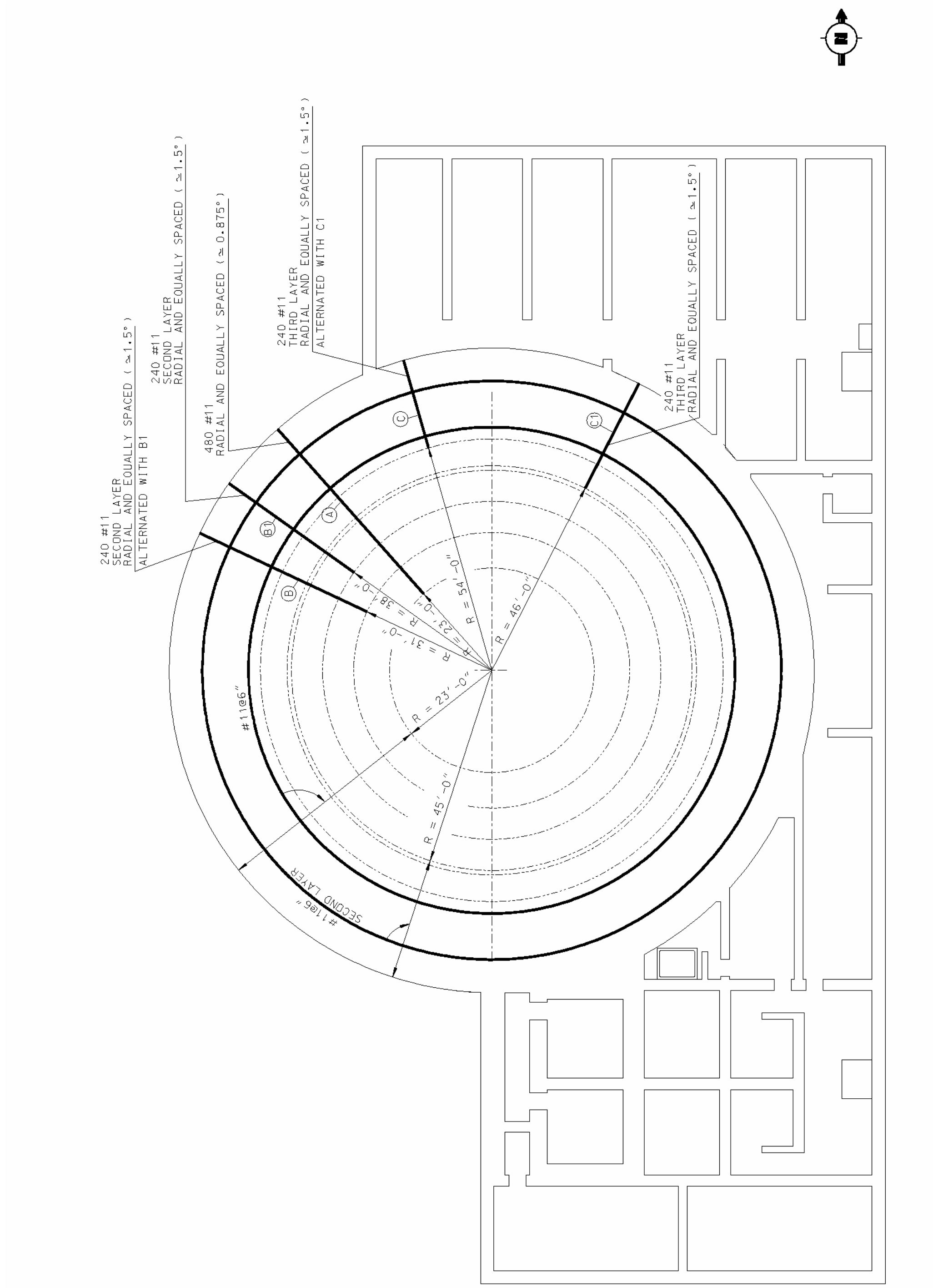


Figure 3.8.5-3 (Sheet 3 of 5)

Basemat Reinforcement – Top Face Below Containment Vessel

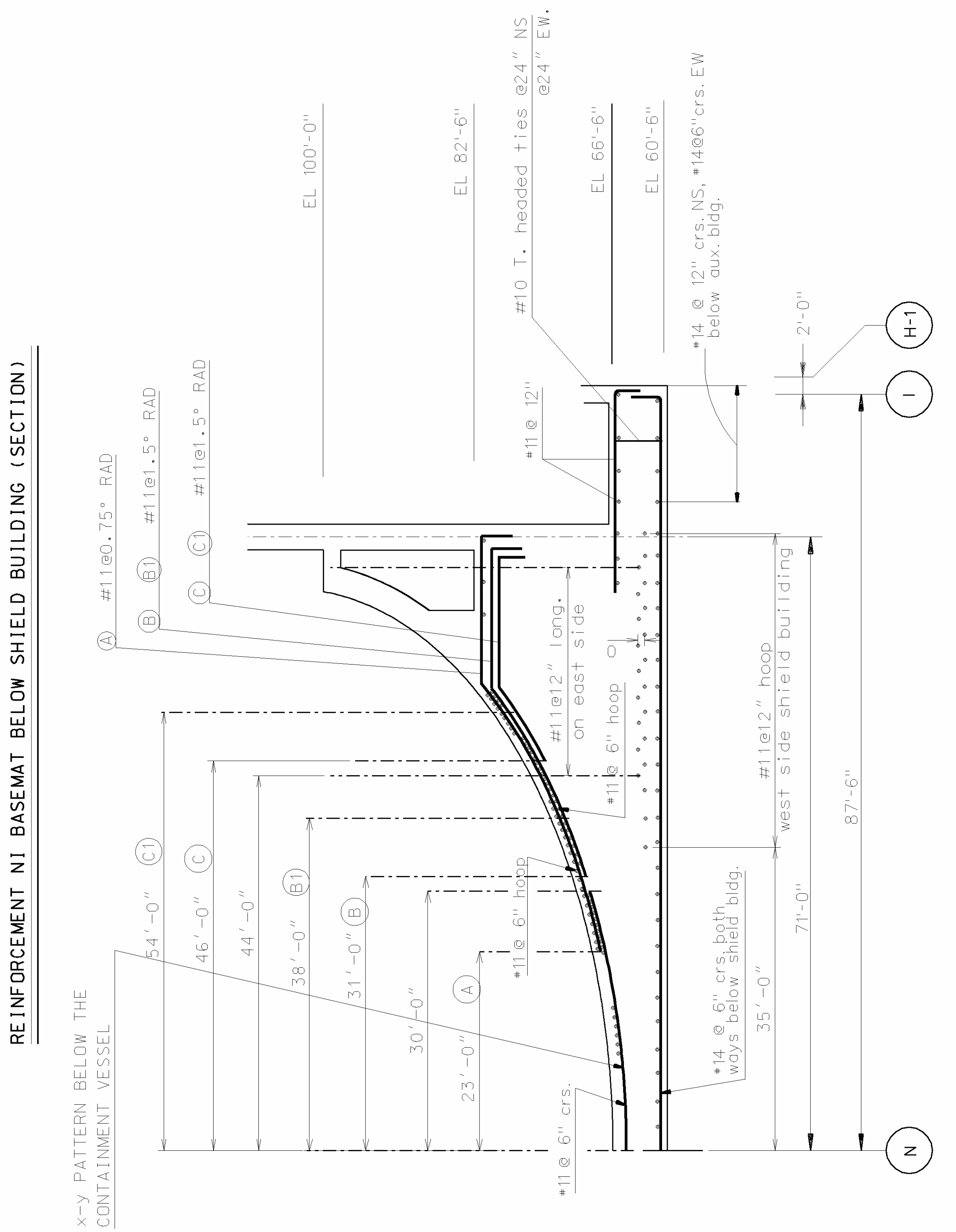
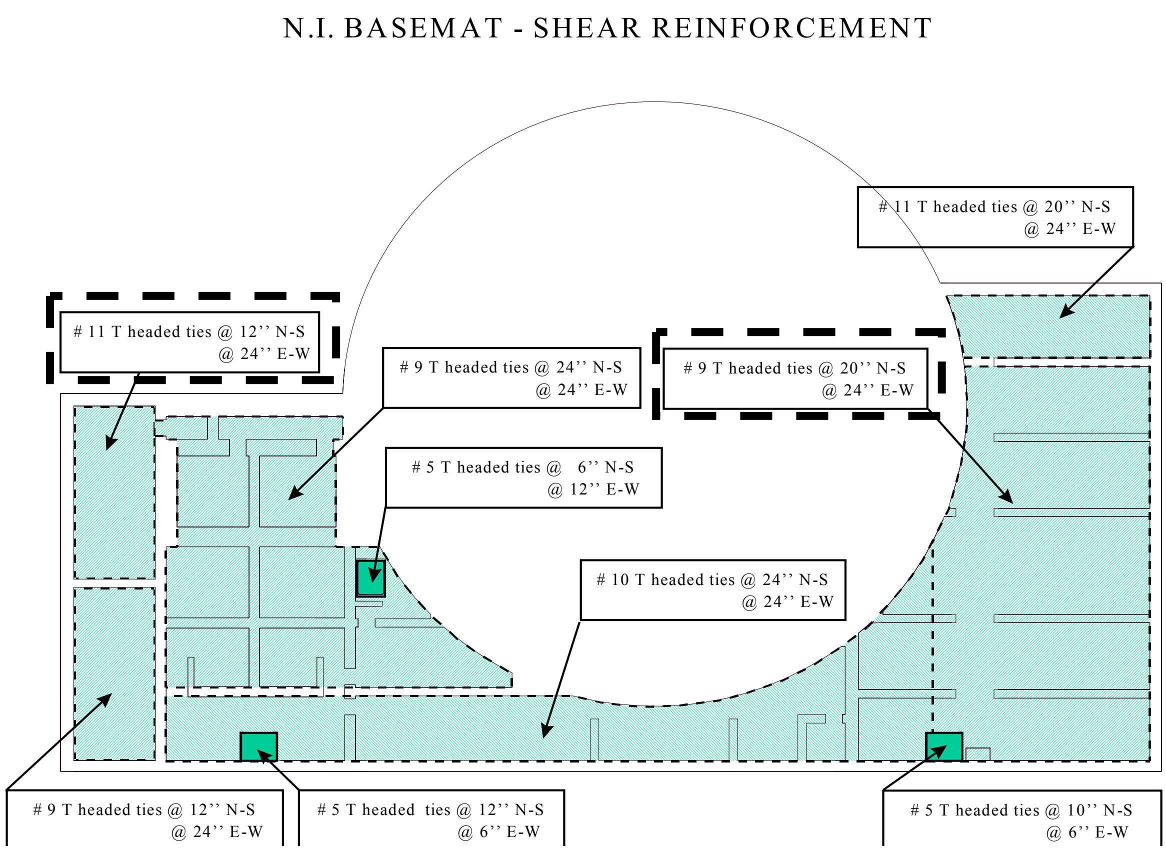


Figure 3.8.5-3 (Sheet 4 of 5)

Basemat Reinforcement – Cross Section



[*Reinforcement in these regions is given in Table 3.8.5-3*]*

Figure 3.8.5-3 (Sheet 5 of 5)

Basemat Shear Reinforcement

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

3.9 Mechanical Systems and Components

3.9.1 Special Topics for Mechanical Components

3.9.1.1 Design Transients

To provide a high degree of integrity for the equipment in the reactor coolant system (RCS), components designed and constructed to the requirements for Class 1 in ASME Code, Section III are evaluated for design, service, and test conditions.

The design conditions include those pressure, temperature, and mechanical loadings selected as the basis for the design. Service conditions cover those normal operating conditions, anticipated transients, and postulated accident conditions expected or postulated to occur during operation. The evaluation of the service and testing conditions includes an evaluation of fatigue due to cyclic stresses.

The following five operating conditions, as defined in ASME Code, Section III, are considered in the design of the reactor coolant system Class 1 components, auxiliary Class 1 components, reactor coolant system component supports, and reactor internals.

Level A Service Conditions - (Normal Conditions) These conditions include any condition in the course of system startup, operation in the design power range, hot standby, and system shutdown other than Level B, Level C, or Level D service conditions or testing conditions. Tests not requiring a pressure greater than the component design pressure are considered to be normal condition design transients.

Level B Service Conditions - (Upset Conditions, Incidents of Moderate Frequency) These conditions include any deviations from Level A service conditions anticipated to occur often enough that the design includes a capability to withstand the conditions without operational impairment. The Level B service conditions include those transients resulting from any single operator error or control malfunction, transients caused by a fault in a system component requiring its isolation from the system, and transients due to loss of load or power. Level B service conditions include any abnormal incidents not resulting in a forced outage and also forced outages for which the corrective action does not include any repair of mechanical damage. The estimated duration of Level B service condition is included in the design specifications.

Level C Service Conditions - (Emergency Conditions, Infrequent Incidents) These conditions include those deviations from Level A service conditions that require shutdown for correction of the conditions or repair of damage in the system. The conditions have a low probability of occurrence but are included to establish that no gross loss of structural integrity will result as a concomitant effect of any damage developed in the system. The postulated occurrences for such events which result in more than 25 strong stress cycles are evaluated for cyclic fatigue using Level B service limits. Strong stress cycles are those having an alternating stress intensity value greater than that for 10^6 cycles from the applicable fatigue design curves.

Level D Service Conditions - (Faulted Conditions, Limiting Faults) These conditions include those combinations of conditions associated with extremely low-probability postulated events whose consequences are such that the integrity and operability of the nuclear energy system may

be impaired to the extent that consideration of public health and safety is involved. Such considerations require compliance with safety criteria as may be specified by regulatory authorities.

Testing Conditions - Testing conditions are those pressure overload tests that include primary and secondary hydrostatic tests and steam generator tube leak tests specified. Other types of tests are classified under one of the other service condition categories.

In addition to the design transients defined for evaluation of the ASME Code, Section III, Class 1 components, other transients are defined to address the same normal operating conditions, anticipated transients, and postulated accident conditions. These alternate transients are developed for evaluations of other effects. For example, a set of transients is developed for equipment qualification (see Section 3.11) and a set for accident analysis (see Chapter 15). These transients have somewhat different assumptions for the number of transients and sequence of events than do the design transients.

To provide a high degree of integrity for the equipment in the reactor coolant system, the transient conditions selected for equipment fatigue evaluation are based upon a conservative estimate of the magnitude and frequency of the temperature and pressure transients that may occur during plant operation.

To a large extent, the specific transients to be considered for equipment fatigue analyses are based upon engineering judgment and experience. The plant condition (PC) categorization defined in ANS N51.1 (Reference 1), which categorizes transients on the basis of expected frequency, are also part of the process to define transients and which service condition applies for a given transient.

The transients selected are severe enough or frequent enough to be of possible significance to component cyclic behavior. The transients selected are a conservative representation of transients that, used as a basis for component fatigue evaluation, provide confidence that the component is appropriate for its application for the 60-year design objective. These transients are described by pertinent variations in pressure, fluid temperature, and fluid flow. Because of the large number of possible operating transients, design transients are chosen to provide a conservative representation for component cyclic analysis. The frequency in some cases is greater than the maximum frequency that defines the plant condition in ANS N51.1 (Reference 1).

The design transients and the number of events of each that are normally used for fatigue evaluations of components are presented in Table 3.9-1. A limited number of events affecting only the core makeup tank or passive residual heat removal heat exchanger are not included in the design transients. Subsections 5.4.13 and 5.4.14 describe these events.

The effects of each transient vary in consequence for each of the analyzed components. For example, the reactor vessel is subject to the pressure and temperature variations in the reactor coolant loop flow, but, the core makeup tank and passive residual heat removal heat exchangers are subject only to the pressure changes for many of the reactor coolant system transients. Additionally, the steam generator is subject to changes in the feedwater and steam system parameters that may have little or no effect on the other Class 1 components.

The individual component fatigue evaluations are based on component specific analyses of the stress levels and cycles of applied stress of the design transients. In many cases, the fatigue evaluations for the individual components combine two or more of the design transients into one bounding condition for that component.

In some cases the use of the total number of the design transients in a component fatigue analysis may indicate the requirement for a significant redesign of a portion of a component. In such cases, the number of one or more of the transients evaluated in the analysis may be reduced. In each case, the number of transients to be included in the analysis is specified in the component design specification.

In accordance with ASME Code, Section III, Level D service conditions and up to 25 stress cycles for Level C service conditions may be excluded from cyclic fatigue analysis. Any Level C service condition in excess of the 25-cycle limit is evaluated for the effect on cyclic fatigue, using Level B criteria. The determination of which transients and seismic events are included in the 25-cycle exclusion is made separately for each component and piping line.

Levels C and D events are included in the design transients to provide the basis for pressure and temperatures used in the component stress analyses of these events. The number of events is given in the description of the transients and in Table 3.9-1 to support the determination that the fatigue evaluations do not have to consider these events.

[*The stress analysis, including analysis of fatigue, of the piping, applicable component nozzles, and piping and component supports includes the effect of thermal stratification and thermal cycling.*]* Thermal stratification may occur in piping when fluid rates are low and do not result in adequate mixing. Thermal cycling due to stratification may occur because of leaking valves or operational practices.

The design of piping and component nozzles in the AP1000 includes provisions to minimize the potential for and the effects of thermal stratification and cycling. [*Piping and component supports are designed and evaluated for the thermal expansion of the piping resulting from potential stratification modes. The evaluation includes consideration of the information on thermal cycling and thermal stratification included in NRC Bulletins 88-08 and 88-11 and other applicable design standards.*]*

The effects of earthquakes are not considered directly in the analyses leading to the fluid systems design transients. The presence or absence of seismic activity has no effect on the input data used for the analyses nor on the resulting pressure, temperature, and flow transients. Therefore, where applicable, in addition to the effects produced by the transients, earthquake loadings must be considered. See subsection 3.9.3 for a description of the seismic loads and other mechanical loads and loading combinations evaluated.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

3.9.1.1.1 Level A Service Conditions (Normal Conditions)

The following reactor coolant system transients are considered normal operating transients (plant condition PC-1 per ANS N51.1) and are analyzed using Level A service limits:

- Reactor coolant pump startup and shutdown
- Plant heatup and cooldown
- Unit loading and unloading between 0 and 15 percent of full power
- Unit loading and unloading at 5 percent of full power per minute
- Step load increase and decrease of 10 percent of full power
- Large step load decrease with steam dump
- Steady-state fluctuations and load regulation
- Boron concentration equalization
- Feedwater cycling
- Core lifetime extension
- Feedwater heaters out of service
- Refueling
- Turbine roll test
- Primary leakage test
- Secondary leakage test
- Core makeup tank high-pressure injection test
- Passive residual heat removal test
- Reactor coolant system makeup

3.9.1.1.1.1 Reactor Coolant Pump Startup and Shutdown

The reactor coolant pumps are started and stopped during such routine operations as plant heatup and cooldown and in connection with recovery from certain transients, such as loss of power. Other (undefined) circumstances may also require pump starting and stopping.

Of the spectrum of reactor coolant system pressure and temperature conditions under which these operations may occur, three conditions have been selected for defining transients:

- Cold condition: 70°F and 400 psig - The minimum pressure required for reactor coolant pump operation may be as low as 100 psig. A pressure of 400 psig is considered a conservative value for design purposes.

- Pump restart condition: 100°F and 400 psig - These conditions are included to cover situations requiring stopping and restarting the pumps after plant heatup has commenced.

- Hot condition: 557°F and 2235 psig

These pressure and temperature values are defined for use in the design and fatigue evaluation processes. Actual pump starting and stopping conditions may be controlled by other factors such as reactor vessel material ductility considerations.

For reactor coolant pump starting and stopping operations, it is assumed that variations in reactor coolant system primary-side temperature and in-pressurizer pressure and temperature are negligible. Temperature and pressure changes in the steam generator secondary side are also assumed negligible. The only significant variables are the primary system flow and the pressure changes resulting from the pump operations.

The following cases are considered.

Case 1 - First Pump Startup (Last Pump Shutdown)

This case represents the variations in reactor coolant loop flow that accompany startup of the first pump, both in the loop containing the pump being started and in the other loop. (The loop in which both pumps remain idle). This case involves a higher dynamic pressure loss in the loop containing the pump being started, but the magnitude of the flow change is less than in Case 2.

For the last pump shutdown case, the transient is the reverse of the first pump startup transient.

Case 2 - Last Pump Startup (First Pump Shutdown)

This case conservatively represents the variations in reactor coolant loop flow that accompany startup of the fourth pump, as applicable. Initially, flow exists through this pump in the reverse direction as the result of starting the other pumps.

For the first pump shutdown case, the transient is the reverse of the last pump startup transient. Case 1 and Case 2 bound the effects of flow and pressure drop on the second and third pumps started, whether the second pump is started in the loop with the first pump running or in the other loop.

Design values for the pump starting/stopping conditions are given in Table 3.9-2 along with the assumed number of occurrences.

An example of the consequence of a pump startup is that the loop flow change associated with pump startup develops a pressure differential in the normal (forward) direction across the divider plate of the steam generator in that loop. In the loop undergoing reverse flow, the direction of the divider plate differential is reversed. The magnitude of the dynamic pressure drop depends on the volumetric flow rate through the loop and on the density and viscosity of the reactor coolant.

3.9.1.1.1.2 Plant Heatup and Cooldown

For the purpose of designing the major reactor coolant system components, the plant heatup and cooldown operations are conservatively represented by uniform ramp temperature changes of 100°F per hour when the system temperature is above 350°F. (For the pressurizer vessel, the design cooldown rate is 200°F per hour.) This rate bounds both potential nuclear heatup operations and cooldown using the steam dump system when system temperatures are greater than 350°F. Below 350°F, only reactor coolant pump heat and small amounts of decay heat are available to heat the reactor coolant system. Cooldown between 350°F and the shutdown temperature of 125°F is accomplished via the normal residual heat removal system. In this range,

a uniform ramp rate of 50°F per hour is considered to bound the temperature changes resulting from these operations.

The number of plant heatup and cooldown operations is defined as 200 each, which corresponds to approximately three occurrences per year for design purposes.

3.9.1.1.1.3 Unit Loading and Unloading Between 0 and 15 Percent of Full Power

The unit loading and unloading cases between the 0 and 15 percent load are represented by continuous and uniform ramp steam load changes, which require 30 minutes for loading and five minutes for unloading. During loading, reactor coolant temperatures are changed from their no-load values to their normal load programmed temperature values at 15 percent load. The reverse temperature change occurs during unloading.

Before loading, it is assumed that the plant is at hot standby, with feedwater cycling from the main or startup feedwater system. Loading commences, and during the first two hours, the feedwater temperature increases to the 15 percent load value, because of steam dump and turbine startup heat input to the feedwater.

After unloading, feedwater heating is reduced, steam dump is reduced to residual heat removal requirements, and feedwater temperature decreases from the 15 percent load value. Reactor coolant system pressure and pressurizer pressure are assumed to remain constant at the normal operating values during these operations.

The number of these loading and unloading transients is assumed to be 500 each for design purposes.

3.9.1.1.1.4 Unit Loading and Unloading at Five Percent of Full Power per Minute

The unit loading and unloading operations are conservatively represented by continuous and uniform ramp power changes of 5 percent per minute between the 15 percent and 100 percent power levels. This load swing is the maximum possible that is consistent with operation under automatic reactor control. The reactor temperature will vary with load prescribed by the reactor control system. The number of loading and unloading operations is defined as 19,800 each, based on one swing per day for the 60-year design objective and on the assumption of a 90 percent availability factor.

The AP1000 features a rod control system that provides a load follow capability without requiring a change in the boron concentration in the coolant. Thus, the reactivity gain available from temperature reduction is not required for load follow, and reduced temperature return to power is not applicable to the AP1000.

3.9.1.1.1.5 Step Load Increase and Decrease of 10 Percent of Full Power

The 10 percent step change in load demand results from disturbances in the electrical network to which the unit is tied. The reactor control system is designed to restore plant equilibrium without reactor trip following a 10 percent step change in turbine load demand initiated from nuclear plant

equilibrium conditions between 15 and 100 percent of full load (the power range for automatic reactor control).

Following a step decrease in turbine load, the secondary-side steam pressure and temperature initially increase. The reactor coolant system average temperature and pressurizer pressure also increase, but this change lags slightly behind the secondary-side change. Because of the coolant temperature increase and the power mismatch between turbine and reactor, the control system automatically inserts the control rods to reduce core power. The reactor coolant temperature then decreases from its peak value to a value below its initial equilibrium value.

Pressurizer pressure also decreases from its peak value and follows the reactor coolant decreasing temperature trend. At some point during the decreasing pressure transient, the saturated water in the pressurizer begins to flash. This reduces the rate of pressure decrease. Subsequently, the pressurizer heaters turn on and restore the pressure to its normal value.

Following a step increase in turbine load, the reverse situation occurs. The secondary-side steam pressure and temperature initially decreases and the reactor coolant average temperature pressure initially decreases. The control system automatically withdraws the control rods to increase core power.

The decreasing pressure transient is reversed by actuation of the pressurizer heaters, and eventually the system pressure is restored to its normal value. The reactor coolant average temperature rises to a value above its initial equilibrium value.

The number of operations is specified as 3000 times each, or 50 times per year, for design purposes.

3.9.1.1.1.6 Large Step Load Decrease With Steam Dump

This transient applies to a step decrease in turbine load from full power. This step decrease in turbine load results in a rapid mismatch between nuclear and turbine power that automatically initiates a secondary-side steam dump and actuates the rapid power reduction system, which prevents both reactor trip and lifting of steam generator safety valves.

After the large step load decrease, reactor power is reduced at a controlled rate, which results in lower flow through the steam dump system.

The AP1000 plant is designed to accept a step load change to house load, without a reactor trip, with up to 40 percent of the load reduction provided by the steam dump capability. The balance of the load reduction is provided by the rapid power reduction system. The number of occurrences of this transient is specified at 200 times for design purposes.

3.9.1.1.1.7 Steady-State Fluctuations and Load Regulation

Reactor coolant pressure and temperature can vary around the nominal (steady-state) values during power operation. These variations can occur at many frequencies but for design purposes two cases are considered.

Initial Fluctuations - Initial fluctuations are due to rod cycling during the first 20 full power months of reactor operation. Reactor coolant temperature is assumed to vary by ± 3°F, and pressure by ± 25 psi once during each 2-minute period. The total number of occurrences is specified as 1.5 x 10^5. The fluctuations are assumed to occur consecutively, but not simultaneously, with random fluctuations.

Random Fluctuations - Reactor coolant temperature is assumed to vary by ± 0.5°F, and pressure by ± six psi, once during each six-minute period. The total number of occurrences for design purposes does not exceed 4.6 x 10^6.

These small, primary-side fluctuations have no effect on the steam generator secondary side.

The above described steady-state fluctuations and the following load regulation transients are considered to be mutually exclusive. Component evaluations are based on the more limiting of either the steady-state fluctuations or the load regulation transients.

Load Regulation - Load regulation refers to the relatively small, rapid fluctuations in load, regarding some nominal operating condition that is the result of the participation of the plant in some form of grid frequency control. The nominal operating condition is either a constant power level or a very slowly changing power level such as that which occurs because of a daily load follow maneuver.

For design purposes it is assumed that the plant experiences load changes of 10 percent of rated load peak-to-peak at a rate of 2 percent of rated load per minute. It is assumed that up to 35 of these load swings may occur during any given day of plant operation. Frequency control capability is to be provided while performing ramp power changes required for load follow maneuvers. This capability is to be provided within 15 to 95 percent of full power. Load regulation is performed with a continuous spray flow.

Assuming continuous operation of the plant in the load regulation mode for the 60-year design objective and accounting for 90 percent availability, the following component cycling limits will not be exceeded:

- Control rod drive mechanism stepping ≤ 15 x 10^6 steps
- Pressurizer spray on-off cycling ≤ 19,809
- Pressurizer backup heater on-off cycling ≤ 19,000

This cycling of the components should be considered to occur in addition to the duty cycles imposed on these components due to other modes of plant operation.

3.9.1.1.1.8 Boron Concentration Equalization

Following any large change in boron concentration in the reactor coolant system, the pressurizer spray is operated to equalize the concentration between the loops and the pressurizer. This can be done by manually operating the pressurizer backup heaters, which causes a pressure increase and spray initiation at a pressurizer pressure of approximately 2260 psia. The pressure increases to approximately 2267 psia before being returned to 2250 psia by the proportional spray. The

pressure is maintained at 2250 psia by spray operation, matching the heat input from the backup heaters, until the concentration is equalized.

Since reactor coolant system boron concentration changes are not required for daily load follow, it is assumed that this operation is performed about once each week. For design purpose the total number of occurrences is placed at 2900.

The operations cause no significant effects on the steam generator secondary side. The only effects of these operations on the primary system are as follows:

- The reactor coolant pressure varies in step with the pressurizer pressure.
- The pressurizer surge line nozzle at the hot leg will experience the temperature transient associated with outflow from the pressurizer.

3.9.1.1.1.9 Feedwater Cycling

The feedwater cycling transient occurs when the plant is being maintained at hot standby or no-load condition. With the plant in the steam pressure mode of steam dump control, a low steam generation rate occurs because of dissipation of decay and/or pump heat. This low steam generation rate decreases steam generator water level.

To compensate for the decreasing level, the steam generators are fed using the startup feedwater control. Either the main or startup feedwater pumps can continuously provide flow to the steam generators and maintain the desired steam generator level. For this case the reactor coolant system transient is relatively moderate.

If the startup feedwater control system is unavailable, the feedwater is provided intermittently in a slug-feeding mode.

Two modes of slug-feeding the steam generators are considered. In the first mode, it is assumed that the steam generators are slug-fed through the startup feedwater nozzle once every two hours. In the second mode, it is assumed that tighter control of steam generator water level is maintained by slug-feeding once every 24 minutes.

For design purposes, the following numbers of feedwater cycling transients are considered:

- Mode 1: Slug feed every 2 hours – 3000 cycles
- Mode 2: Slug feed every 24 minutes – 15,000 cycles

The component designers consider both modes of slug-feeding. Each component evaluation is based on the more limiting of the two modes.

3.9.1.1.1.10 Core Lifetime Extension

These transients occur at the end of core life when the critical boron concentration required to maintain full thermal power conditions becomes less than achievable (approximately 10 ppm). To extend core lifetime beyond this point, the operator does the following:

- Allows the reactor coolant system average temperature to decrease below the normal programmed temperature, thereby adding reactivity to the core through the negative moderator temperature coefficient.
- Manually controls the turbine to maintain full electrical load until the turbine throttle valves have fully opened.
- Reduces steam flow by an amount that will maintain the plant at full rated electrical load after a feedwater heater has been taken out of service and allow plant conditions to reach a new steady state.
- Takes a feedwater heater out of service.

This process is repeated until the maximum allowable feedwater heaters have been taken out of service and the turbine throttle valves have fully opened.

For design purposes, the number of occurrences of these transients is a total of 40 transients. During this mode of operation, the plant is not capable of daily load follow operation. Thus, this transient is considered separately from unit loading and unloading transients.

3.9.1.1.1.11 Feedwater Heaters Out of Service

These transients occur when one or more feedwater heaters are taken out of service. During the time that the heaters are out of service, the operator maintains the plant at full rated thermal load. To accomplish this, the operator performs the following:

- Calculates the appropriate steam flow reduction which will maintain the plant at full rated thermal load after the heater has been taken out of service.
- Reduces steam flow by the appropriate amount and allow plant conditions to reach a new steady state (approximately 10 minutes).
- Takes heater (or heaters) out of service.

The transient is based on the maximum allowable number of heaters out of service. For design purposes, the number of occurrences of this transient is a total of 180.

3.9.1.1.1.12 Refueling

At the beginning of the refueling operation, the reactor coolant system is assumed to have been cooled down to 140°F. The vessel head is removed and the refueling canal is filled. This is done by transferring water from the in-containment refueling water storage tank, which is

conservatively assumed to be at 70°F, into the reactor coolant system by means of the spent fuel pit cooling pumps. The refueling water flows directly into the reactor vessel via one of the passive safety injection system connections to the vessel.

This operation is assumed to occur 40 times over the expected plant design. This transient is experienced only by the primary system.

3.9.1.1.1.13 Turbine Roll Test

This transient is imposed upon the plant during the hot functional test for turbine cycle checkout. Reactor coolant pump power is used to heat the reactor coolant to operating temperature (no-load conditions), and the steam generator is used to perform a turbine roll test. However, the plant cooldown during this test exceeds the 100°F per hour design rate.

The number of such test cycles is specified at 20 times, to be performed at the beginning of plant operation before reactor operation. This transient occurs before plant startup, so the number of cycles is independent of other operating transients.

The transient curves and the number of cycles are based on a conservatively high steam flow rate for turning the turbine.

3.9.1.1.1.14 Primary-Side Leakage Test

A leakage test is performed after each opening of the primary system. During this test the primary system pressure is raised (for design purposes) to 2500 psia, with the system temperature above the minimum temperature imposed by reactor vessel material ductility requirements, while the system is checked for leaks.

The secondary side of the steam generator is pressurized so that the pressure differential across the tubesheet does not exceed 1600 psi. This is accomplished with the steam, feedwater, and blowdown lines closed.

For design purposes the number of occurrences is a total of 200 cycles.

3.9.1.1.1.15 Secondary-Side Leakage Test

A secondary side leakage test is performed after each opening of the secondary system to check closures for leakage. For design purposes, it is assumed that the steam generator secondary side is pressurized to just below its design pressure to prevent the safety valves from lifting. So that a secondary-side to primary-side pressure differential of 670 psi is not exceeded, the primary side must also be pressurized. The 670 psi differential is the steam generator design differential pressure for secondary-to-primary pressure. The primary system must be above the minimum temperature imposed by reactor vessel material ductility requirements (that is, between 120°F and 250°F). It is assumed that this test is performed 80 times for design purposes.

3.9.1.1.1.16 Core Makeup Tank High Pressure Injection Test

During hot functional testing with the reactor coolant system in hot standby condition, the core makeup tank injection flow rate is tested. The reactor coolant system temperature is 400°F. The core makeup tank injection lines are opened, and the core makeup tank injects cold water into the reactor coolant system. When valves are cycled during power, there is no effect on temperature or pressure.

3.9.1.1.1.17 Passive Residual Heat Removal Test

During hot functional testing with the reactor coolant system in hot standby condition, the passive residual heat removal flow and heat transfer rates are tested. Passive residual heat removal flow is initiated by opening the passive residual heat removal isolation valves. The passive residual heat removal cools the reactor coolant system for up to 30 minutes.

3.9.1.1.1.18 Reactor Coolant System Makeup

The chemical and volume control system makeup subsystem is used to accommodate normal minor leakage from the reactor coolant system. On a low programmed pressurizer level signal one of the chemical and volume control system makeup pumps starts automatically in order to provide makeup. The pump automatically stops when the pressurizer level increases to the high programmed setpoint. The addition of the makeup water to the reactor coolant system via the chemical and volume control system purification loop and attendant changes in reactor coolant system parameters constitute the reactor coolant system makeup design transient. The total number of occurrences of the makeup transient is 2820, which corresponds to once per week during the plant design objective of 60 years assuming a 90 percent availability factor for the plant.

3.9.1.1.2 Level B Service Conditions (Upset Conditions)

The following paragraphs describes the reactor coolant system upset condition transients, which are considered to be plant condition PC-2 and PC-3 per ANS N51.1. From the standpoint of the use of design transient in the evaluation of cyclic fatigue, there is no difference between PC-2 and PC-3. These transients are analyzed using Level B service limits and are as follows:

- Loss of load
- Loss of power
- Reactor trip from reduced power
- Reactor trip from full power
  Case A - with no inadvertent cooldown
  Case B - with cooldown and no safeguards actuation
  Case C - with cooldown and safeguards actuation
- Control rod drop - three cases

- Cold overpressure
- Inadvertent safeguards actuation - three cases
- Partial loss of reactor coolant flow
- Inadvertent reactor coolant system depressurization
- Excessive feedwater flow
- Loss of power with natural circulation cooldown
  Case A - loss of power with natural circulation cooldown with onsite ac power
  Case B - loss of power with natural circulation cooldown without onsite ac power

Under the upset condition transients listed, 505 reactor trip cases are assumed. A total of 505 reactor trips for design purposes exceeds the design goal. The design goal for the AP1000 is less than one unplanned trip per year. The number of reactor trips in the design transients represents a conservative number for the analysis of cyclic stresses in the components and is not to be considered an estimate of expected plant performance.

For some component or portions of components, the number of reactor trips analyzed for the effects of cyclic loads may be reduced from 505. In each case the number of reactor trips analyzed is greater than the design goal of one per year.

3.9.1.1.2.1 Loss of Load

This transient involves a step decrease in turbine load from full power (turbine trip) without immediate automatic reactor trip or rapid power reduction. These conditions produce the most severe pressure transient on the reactor coolant system under upset conditions. The reactor is assumed to trip as a consequence of a trip initiated by the reactor protection system. Since redundant means for tripping the reactor are provided by the reactor protection system, a transient of this nature is not expected, but is included to confirm conservative component design.

The number of occurrences of this transient is specified at 30 times for design purposes.

3.9.1.1.2.2 Loss of Power

This transient applies to a blackout situation involving the loss of outside electrical power to the station, assumed to be operating initially at 102 percent power, followed by reactor and turbine trips. The reactor coolant pumps are de-energized, as are electrical loads connected to the turbine-generator bus, including the main feedwater and condensate pumps.

As the reactor coolant pumps coast down, reactor coolant system flow reaches an equilibrium value through natural circulation. This condition permits removal of core residual heat through the steam generators, which receive feedwater from the startup feedwater system. For this event reactor coolant temperature stabilizes at hot standby conditions.

The number of occurrences of this transient is specified at 30 times for design purposes.

For one occurrence, a worst case is postulated in which the shell side of a single steam generator is assumed to be emptied after the blackout. The startup feedwater flow is then delivered into the hot, dry shell side. The steam generator tube and secondary shell integrity are evaluated for this condition.

3.9.1.1.2.3 Reactor Trip from Reduced Power

A significant percentage of reactor trips occur at low power as the plant is being brought up from hot standby to power. The low power reactor trip is provided to bound these occurrences without the excessive conservatism associated with the reactor trip from full power. The transient is assumed to start at 25 percent load, which bounds the conditions associated with achieving criticality, turbine roll, and turbine synchronization; establishing automatic rod control; and making the transitions in feedwater control from the startup feedwater nozzle to the main feedwater nozzle.

Reactor coolant system temperature and pressure variations are similar to those of reactor trip from full power, but are smaller. The transients continue until the reactor coolant and steam generator secondary side temperatures are in equilibrium at zero power conditions. Controlled steam dump and startup feedwater remove any core residual heat and prevent steam generator safety valve actuation. For design purposes, 180 reactor trips from reduced power are postulated.

3.9.1.1.2.4 Reactor Trip from Full Power

Reactor trips from full power may occur for a variety of reasons. The reactor coolant temperature and pressure undergo rapid decreases from full power values as the reactor protection system causes the control rods to move into the core. Transients also occur in the secondary side of the steam generator because of continued heat transfer from the reactor coolant through the steam generators.

These transients continue until the reactor coolant and steam generator secondary side temperatures are in equilibrium at zero power conditions. Continuation of feedwater flow and controlled steam dump remove the core residual heat and prevent steam generator safety valve actuation. For design purposes, reactor trip from full power is assumed to occur 120 times.

Three reactor trip cooldown transients are considered.

Case A - Reactor Trip With No Inadvertent Cooldown

Steam and feedwater flow are both controlled to bring the plant back to no-load conditions and maintain it at no load. For design purposes, 50 occurrences of this transient are specified.

It is assumed that for most reactor trip Case A transients, the turbine control system operates as designed. For five of the reactor trip Case A transients, it is conservatively assumed that the control system fails, which results in an emergency turbine overspeed. This situation could be initiated with malfunction of the turbine control system, which results in a turbine speed increase past the overspeed trip setpoint. It is assumed that the reactor then trips and that the turbine speed increases to 120 percent of nominal, with accompanying proportional increases in generator bus

frequency, reactor coolant pump speed and reactor coolant flow rate. None of the other reactor coolant system primary side, pressurizer, or steam generator secondary side variables is affected.

For design purposes it is assumed that the emergency turbine overspeed constitutes a special case of the reactor trip with no inadvertent cooldown transient. Thus, for five of the 50 occurrences, the effects of the reactor coolant flow variation are considered in addition to the basic pressure and temperature variations.

Case B - Reactor Trip With Cooldown and No Safeguards Actuation

Following the reactor trip, the steam generator water level falls because of shrinkage in the secondary side. This is assumed to cause startup feedwater flow to actuate on low steam generator water level. For this case, it is assumed that the startup feedwater is actuated within five seconds of the reactor trip. Both main and startup feedwater flow continue for approximately one minute after the reactor trip. This maintains a high heat transfer rate through the steam generator, which continues to drive the primary side pressure and temperature down. The reactor coolant system pressure decreases to just above the safety injection setpoint. The flow through the main feedwater nozzle is then terminated, and flow through the startup feedwater nozzle is continued. The plant is then brought back to the no-load condition.

For design purposes, 50 occurrences of this transient are specified.

Case C - Reactor Trip with Cooldown and Passive Residual Heat Removal Actuation

This transient is similar to Case B, but it is assumed that the steam generator secondary side shrinkage is sufficient to actuate the passive residual heat removal heat exchanger of the passive core cooling system on low level.

For design purposes, 20 occurrences of this transient are specified.

3.9.1.1.2.5 Control Rod Drop

This transient occurs when one or more rod cluster control assemblies inadvertently drop into the core because of equipment failure or operator error. If this rod drop occurs while the plant is at power, pressure and temperature transients will occur in the reactor coolant system and on the secondary side of the steam generators. The severity of the rod drop accident depends on a number of factors, such as the number and worth of rod cluster control assemblies that drop, and the value of the moderator temperature coefficient of reactivity. The control rod drop cases assume the control banks to be fully withdrawn.

The following three types of control rod drop transients are postulated for design purposes.

Control Rod Drop - Case A

This transient occurs when the worth of the dropped control rods is high. When the rods drop, reactor power quickly decreases, but plant load is maintained at its initial value.

The steam load-reactor power mismatch causes the plant to cool down, eventually leading to a reactor trip on low pressurizer pressure. Following the reactor trip, the steam generator water level falls because of shrinkage in the secondary side. This is assumed to cause startup feedwater flow to actuate on low steam generator level, thus continuing to drive the primary system temperature and pressure down. The transient is terminated just above the safeguards actuation setpoint.

The responses of the various plant parameters during this transient are identical to those of reactor trip from full power - Case B. For design purposes, 30 occurrences of this transient are specified in addition to the 50 occurrences of reactor trip from full power.

Control Rod Drop - Case B

This transient occurs when the worth of the dropped control rods is relatively low and when the moderator temperature coefficient of reactivity is zero. When the rod drops, reactor power is reduced. However, plant steam load is maintained at its initial value.

The steam load-reactor power mismatch causes the plant to cool down. With a zero moderator temperature coefficient of reactivity, no reactor power recovery occurs. Plant cooldown continues, causing a reactor trip due to low pressurizer pressure, which is then followed by turbine trip. The resultant shrinkage of the steam generator water mass actuates startup feedwater flow. Introduction of the startup feedwater into the steam generators continues to cool the plant. Pressure drops to just below the safeguards actuation setpoint and the passive safety injection system is actuated.

The response of the various plant parameters during this transient are very similar to those of reactor trip from full power - Case C.

The control rod drop - Case B transient is bounded by the reactor trip from full power - Case C transient. The specified number of occurrences of full power reactor trip - Case C transients incorporates the control rod drop - Case B transient frequency of occurrence.

Control Rod Drop - Case C

As in Case B, this transient occurs when the worth of the dropped rod is relatively low. For this case, however, the rod drop is considered to occur when the moderator temperature coefficient of reactivity is negative. When the rod drops, reactor power is reduced but no trip occurs.

However, plant steam load is maintained at the initial value through the transient.

The steam load-reactor power mismatch causes the plant to cool down. With a negative moderator temperature coefficient of reactivity, reactor power returns to its initial value. The plant eventually stabilizes, with reactor power, plant steam flow, reactor coolant system pressure, and pressurizer pressure equal to their initial values, but the reactor coolant system temperature and steam generator secondary-side temperature and pressure are lower.

The magnitude of the reactor coolant system temperature reduction is proportional to the relative worth of the dropped control rod and the negative moderator temperature coefficient of reactivity.

For design purposes, 30 occurrences of this transient are specified. The Case B transients are included in the 30 transients.

At the end of the control rod drop - Case C transient, plant parameters stabilize at their final values. After plant parameters achieve their final values, the plant remains at these conditions indefinitely. Subsequently, plant parameters are returned to their initial values.

Following initiation of recovery, hot and cold leg temperatures and steam generator steam temperature and pressure return to their initial values, consistent with normal plant heatup rates. Pressurizer water volume returns to its initial value in about the same amount of time as the return of hot and cold leg temperatures to their initial values. Pressurizer surge rate variation is consistent with the increase in pressurizer water level.

3.9.1.1.2.6 Cold Overpressure

The safety valve located in the residual heat removal pump suction piping provides the capability for additional reactor coolant system inventory letdown in order to maintain the reactor coolant system pressure consistent with the reactor vessel pressure temperature limits, as required by Appendix G of 10 CFR Part 50. Reactor coolant system cold overpressurization occurs at low temperature (below 350°F) during plant heatup or cooldown, and can occur with or without a steam bubble in the pressurizer. A cold overpressurization is especially severe when the reactor coolant system is water solid. The event is inadvertent, and can be generated by an equipment malfunction or an operator error.

Cold overpressure events are initiated by either a mass addition that exceeds normal letdown capabilities, or a heat addition that attempts to expand the reactor coolant system water volume.

Under water-solid conditions, a worst-case scenario, the mass addition causes an increase in system pressure until the relief valve set pressure, plus accumulation, is reached. The relief valve remains open, with the system pressure stabilizing at the set pressure plus accumulation, until the mass injection is terminated by the operator. Heat addition, also under water-solid conditions, results in a system pressure increase that eventually is terminated by the relief valve.

Once thermal equilibrium is established between the heat source and the reactor coolant system, and the volume expansion has been let down through the relief valve, system pressure stabilizes at the relief valve set pressure.

Fifteen reactor coolant system cold overpressure events, as described above, are specified for design purposes.

3.9.1.1.2.7 Inadvertent Safeguards Actuation

A spurious system-level actuation of the passive core cooling system results in an immediate reactor trip followed by actuation of the various components of the passive core cooling system. The resulting transient is bounded by the reactor trip Case C. The number of reactor trip transients is sufficient to cover a system-level inadvertent safeguards actuation.

A spurious actuation of the passive residual heat removal heat exchanger isolation valves or the core makeup tank valves causes cold reactor coolant to flow into the reactor coolant system. Rapid changes in the temperature of the core makeup tank or passive residual heat removal heat exchanger and associated piping occur. Ten events of this limited transient are postulated.

3.9.1.1.2.8 Partial Loss of Reactor Coolant Flow

This transient applies to a partial loss of flow from full power in which a reactor coolant pump is tripped out of service as a result of loss of power to that pump. The consequences of such an accident are a reactor trip on low reactor coolant flow, followed by a turbine trip; actuation of startup feed control; and automatic opening of the steam dump system. Flow reversal occurs in the associated cold leg. The normal flow direction is maintained in the hot leg of the affected loop but at a reduced rate. Flow through the operating pump in this loop increases.

Operation of the steam dump system tends to bring the plant toward no-load conditions. Cold feedwater from the startup feedwater system then enters the steam generators, causing the plant to cool down. This cooldown continues until termination of startup feed water. The plant is then returned to no-load conditions.

The number of occurrences of this transient is specified as 60 times for design purposes.

3.9.1.1.2.9 Inadvertent Reactor Coolant System Depressurization - Umbrella Case

Several events can be postulated as occurring during normal plant operation that cause rapid depressurization of the reactor coolant system. These include the following:

- Actuation of a single pressurizer safety valve with failure of the valve to reclose
- Malfunction of a single pressurizer pressure controller causing two pressurizer spray valves to open
- Inadvertent opening of one pressurizer spray valve
- Inadvertent opening of the auxiliary spray valve

Umbrella Case - Of these events, the pressurizer safety valve actuation causes the most severe reactor coolant system pressure and temperature transients. It is used as an umbrella case to conservatively represent the reactor coolant pressure and temperature variations arising from any of them.

Although inadvertent actuation of the pressurizer spray is included among the transient events covered by the umbrella case, the pressurizer safety valve actuation case selected to represent the depressurization transients does not involve spray operation. Therefore, for the umbrella case, it is assumed that pressurizer spray is not actuated and that no temperature transients due to flow occur at the spray nozzle.

Inadvertent Pressurizer Spray - The inadvertent pressurizer spray transient represents the depressurization transient, with the most significant temperature variations on portions of the

pressurizer, spray nozzle, and spray piping. Should auxiliary spray flow be inadvertently initiated, it could cause a rapid temperature change at the pressurizer spray nozzle and on the pressurizer vessel. Therefore, to provide a conservative design for these components, an inadvertent pressurizer spray transient is defined.

An inadvertent pressurizer spray occurs if the normal spray valve is opened during normal plant operation because of either failure of a control component or operator error. This introduces water at reactor coolant system cold leg temperature into the pressurizer. The flowrate is assumed to be the maximum design spray flowrate. This transient results in a pressure decrease and, eventually, in a low-pressure reactor trip.

An inadvertent auxiliary spray occurs if the auxiliary spray valve is opened during normal plant operation because of either failure of a control component or operator error. The opening of the auxiliary spray valve causes an inadvertent spray transient only during the limited time that the makeup pump in the chemical volume and control system is operating. The inadvertent auxiliary spray introduces cold water into the pressurizer, which results in a sharp pressure decrease and, eventually, in a low-pressure reactor trip.

The temperature of the auxiliary spray flow is dependent upon the performance of the regenerative heat exchanger. The most conservative case assumes that the letdown stream is shut off and that unheated charging fluid enters the 653°F pressurizer. It is assumed that the temperature of the spray water is 70°F and that the spray flow rate is equal to the normal charging rate.

For both cases, it is also assumed that the spray flow continues for five minutes before it is shut off and that the temperature changes at the pressurizer and spray nozzle occur as steps. For design purposes, it is assumed that no reactor coolant temperature changes occur as the result of inadvertent spray.

For design purposes, 20 occurrences of the inadvertent reactor coolant system depressurization transient are specified. Component evaluations are based on the more limiting of either the umbrella case or the inadvertent spray case. For those components for which the limiting transient is caused by the inadvertent pressurizer spray transient, 10 occurrences of inadvertent normal spray and five occurrences of inadvertent auxiliary spray are postulated.

3.9.1.1.2.10 Excessive Feedwater Flow

An excessive feedwater flow transient is conservatively defined as an umbrella case to cover the occurrence of several events of the same general nature. The postulated transient results from inadvertent opening of a feedwater control valve while the plant is at the hot standby or no-load condition, with the feedwater, condensate, and heater drain systems in operation.

It is assumed that the stem of a feedwater control valve fails and the valve immediately reaches the full open position. In the steam generator directly affected by the malfunctioning valve (failed loop), the feedwater flow step increases from essentially zero flow to the value determined by the system resistance and the developed head of the operating feedwater pumps. Steam flow is assumed to remain at zero.

The passive safety injection system is actuated on a low pressurizer pressure signal. Main feedwater flow is effectively isolated on the safety injection signal.

This transient is assumed to occur 30 times for design purposes.

3.9.1.1.2.11 Loss of Power with Natural Circulation Cooldown

This event is the same as a loss of power transient, except that the reactor coolant system temperature is reduced by natural circulation through the operation of either the startup feedwater pumps and steam dump through the power-operated relief valves if onsite power is available or the passive residual heat removal system transferring heat to the in-containment refueling water storage tank if onsite power is not available. For design purposes 30 natural circulation cooldown occurrences, are assumed. These two cases are discussed below.

Case A - Loss of Power with Natural Circulation Cooldown with Onsite ac Power

For this case, natural circulation cooldown is performed with onsite ac power available. This permits operation of the startup feedwater pumps which enables steam dump through the steam generator power-operated relief valves. This transient is analyzed assuming at least one onsite diesel is operable. For this case the startup feedwater pumps operate and the control rod drive mechanism fan coolers operate to maintain the temperature of the reactor vessel head close to the temperature of the remainder of the reactor vessel. For design purposes, 20 occurrences of this transient are assumed.

Case B - Loss of Power with Natural Circulation Cooldown without Onsite ac Power

For this case, the reactor coolant is cooled by natural circulation with the passive residual heat removal heat exchangers. For this case, no credit is taken for nonsafety-related equipment including the diesel generators. For design purposes, 10 occurrences of this transient are assumed.

3.9.1.1.3 Level C Service Conditions (Emergency Conditions)

The following paragraphs describe the reactor coolant system emergency condition transients considered to be plant condition PC-4 per ANS N51.1. A list of these transients follows. The effect of these events are analyzed using Service Level C limits. As noted previously, up to 25 strong stress cycles due to these transients are not analyzed for cyclic fatigue. Any cycles exceeding the 25 excluded are analyzed for cyclic fatigue using Service Level B limits. The mechanical loads due to pipe rupture are analyzed using Service Level D limits. See subsection 3.6.2 for a discussion of the analysis of mechanical loads due to pipe break.

- Small loss of coolant accident
- Small steam line break
- Complete loss of flow
- Small feedwater line break
- Steam generator tube rupture
- Inadvertent opening of automatic depressurization system valves

3.9.1.1.3.1 Small Loss-of-Coolant Accident

For design transient purposes, the small loss-of-coolant accident is a pipe break equivalent to the severance of a 1-inch ID branch connection to the reactor coolant system. It is assumed that the passive core cooling system is actuated and that it delivers water at a minimum temperature of 70°F to the reactor vessel.

It is assumed that this transient occurs five times for design purposes.

3.9.1.1.3.2 Small Steam Line Break

For design purposes, a small steam line break is a break equivalent to a steam generator safety valve opening and remaining open.

For design purposes, it is assumed that this transient occurs five times.

3.9.1.1.3.3 Complete Loss of Flow

This accident involves a complete loss of flow from full power resulting from the simultaneous loss of power to all reactor coolant pumps. The consequences are a reactor trip on low pump speed, followed by an automatic turbine trip.

This event is considered to be bounded by the loss of power transient. The frequency of occurrence of loss of power transients incorporates the frequency of occurrence of complete loss of flow accidents.

3.9.1.1.3.4 Small Feedwater Line Break

This transient is postulated as a small break in the piping between the steam generator and the main feedwater isolation valve. The main feedwater control system is assumed to malfunction. The malfunction of the main feedwater flow in the affected loop is equivalent to the fluid spilling through the break. No main feedwater is supplied to either steam generator.

After reactor trip, the main feedwater control system is assumed to be lost and reverse flow is assumed to be initiated from the pipe with the break. During the course of the transient, reactor trip, turbine trip, the passive core cooling system and the startup feedwater system are actuated because of low level in the steam generator.

For design purposes, this transient is assumed to occur five times.

3.9.1.1.3.5 Steam Generator Tube Rupture

This transient is postulated as the double-ended rupture of a single steam generator tube, which results in decreases in pressurizer level and reactor coolant pressure. Assuming no operator action, the reactor eventually trips on overtemperature ΔT or low pressurizer pressure. Reactor trip initiates a turbine trip. Reactor coolant system pressure continues to decrease after the trip because of energy transfer from the primary system to the secondary side and continued primary to secondary leakage through the ruptured steam generator tube. Continued reactor coolant system

leakage results in an actuation of the passive core cooling system because of low pressurizer level or pressure.

For design purposes this transient is assumed to occur five times.

3.9.1.1.3.6 Inadvertent Opening of Automatic Depressurization System Valves

Rapid depressurization of the reactor coolant system results from the inadvertent opening of the automatic depressurization system valves. Inadvertent opening of the automatic depressurization system valves during normal plant power operation causes the most severe reactor coolant system pressure and temperature transients of all the inadvertent reactor coolant system depressurization transients. This event occurs by:

- Inadvertent opening of two 4-inch or 8-inch motor-operated automatic depressurization system valves connected to the pressurizer. Inadvertent opening of the larger valves connected to the reactor coolant system hot legs is not possible at normal operating pressure.

- Inadvertent automatic depressurization system actuation due to a spurious system level signal.

For design purposes, 15 occurrences of the inadvertent opening of automatic depressurization system valves transient are assumed.

3.9.1.1.4 Level D Service Condition (Faulted Conditions)

The following paragraphs discuss the reactor coolant system faulted condition transients considered to be plant condition PC-5 per ANS/ANSI N51.1. A list of these transients follows. These transients are analyzed using Level D service limits and are not analyzed for fatigue due to cyclic loads. See subsection 3.6.2 for a discussion of the analysis of mechanical loads due to pipe break.

The components are not evaluated for the dynamic effects of pipe rupture for the pipe break events when the requirements for mechanistic pipe break have been satisfied for the connecting piping. See subsection 3.6.3 for a discussion of the leak-before-break requirements for mechanistic pipe break. The maximum fluid pressure on components is evaluated for these events when leak-before-break requirements are satisfied.

- Reactor coolant pipe break (large loss-of-coolant accident)
- Large steam line break
- Large feedwater line break
- Reactor coolant pump locked rotor
- Control rod ejection

Each of these accidents is evaluated for one occurrence only.

3.9.1.1.4.1 Reactor Coolant Pipe Break (Large Loss-of-Coolant Accident)

Following a rupture of a reactor coolant pipe or connecting branch line that results in a large loss of coolant, the primary system pressure decreases rapidly. This rapid decrease causes the primary system temperature to decrease. Because of the rapid blowdown of coolant from the system and the comparatively large heat capacity of the metal sections of the components, it is likely that the metal will remain at or near operating temperature during blowdown. The passive safety injection system is actuated to introduce water, at an assumed minimum temperature of 70°F, into the reactor coolant system (reactor vessel). The safety injection signal also trips the reactor and the turbine.

3.9.1.1.4.2 Large Steam Line Break

This transient is based on a double-ended rupture of a main steam line. The analyses performed are based on the following conservative assumptions:

- The plant is initially at no-load condition.
- The steam line break results in an immediate reactor trip.
- Main steam line isolation valves are initially open.
- The passive core cooling system operates as designed, and no single failures are assumed. This maximizes the extent and rate of plant cooldown.
- Reactor coolant pumps continue to operate until tripped on core makeup tank actuation coincident with low pressurizer water level.

An alternate definition of large steam break if postulated for evaluation of steam generator pressure boundary components, with respect to stress levels in the steam generator tubes and tubesheet, may represent a more severe transient. The alternate definition is as follows: If the break should occur while the plant is operating at full power instead of no load, and the break is located outside of containment, the affected steam generator will quickly blow down to atmospheric pressure. Flow through the startup feedwater nozzle is then delivered to the hot, dry shell side of the affected steam generator. The primary side pressurizes to 2600 psia (set pressure of pressurizer safety valves plus one percent set pressure error plus 3 percent accumulation). This results in a large differential pressure across the tubes and tubesheet. The combination of parameters giving the most conservative results is used.

The simultaneous, complete severance of both a main steam line and a feedwater line is not a credible event in the AP1000. In addition to the application of criteria to demonstrate leak-before-break on these lines, layout and support requirements are imposed to prevent extensive steam line or feedwater line displacement following rupture.

3.9.1.1.4.3 Large Feedwater Line Break

This postulated accident involves the double-ended rupture of a main feedwater line, which results in rapid blowdown of the affected steam generator and termination of feedwater flow to the other. The plant is assumed to be operating at an initial power level of 102 percent of design rating, with temperatures 4°F higher than nominal, full power values when the break occurs. The feedwater line break results in immediate reactor and turbine trips. The passive core cooling system is actuated, the passive residual heat removal heat exchanger operates, and the reactor coolant pumps are tripped.

In the analysis, no credit is taken for operation of pressure control systems, steam dump, or steam generator power-operated relief valves. The intact steam generator feeds the break through the main steam header after the faulted steam generator discharges its liquid inventory. Steam flow continues until the main steam lines are isolated on low steam line pressure.

3.9.1.1.4.4 Reactor Coolant Pump Locked Rotor

This accident is based on the seizure of the rotating assembly of a reactor coolant pump rotor, with the plant operating at full power. Reactor trip occurs rapidly, as the result of low coolant flow in the affected cold leg. Assumptions made in the analysis include the following:

- Initially the plant is operating at 102 percent of design rating.
- T_{avg} is initially 4°F above the program value.
- No return to criticality occurs in the core.
- No credit is taken for reactor coolant system pressure control.

For the determination of the increase in pressure and response of the reactor core to the reduction in flow, the seizure is assumed to occur instantaneously. For the evaluation of dynamic effects imposed on the pump casing, steam generator, and connecting piping, the rotating assembly is assumed to come to a stop rapidly but not instantaneously. See subsection 5.4.1 for a discussion of the time for a locked rotor to occur.

Level D pressure limits are applied to the affected reactor coolant pump, steam generator channel head and piping, and Level B pressure limits are applied to the rest of the reactor coolant system. The system effects and the maximum fluid pressure are evaluated for this condition on components not affected by the dynamic effects.

3.9.1.1.4.5 Control Rod Ejection

This accident is based on the single most reactive control rod being instantaneously ejected from the core. This reactivity insertion in a particular region of the core causes a severe pressure increase in the reactor coolant system in such a way that the pressurizer safety valves will lift. It also causes a more severe temperature transient in the loop associated with the affected region (the hot loop) than in the other loop.

Since the pressure boundary of the control rod drive mechanism is constructed using the requirements of the ASME Code, Section III, the ejection of the control rod is postulated as a

nonmechanistic event and not as the result of a rupture of the control rod drive housing. The analysis of the system response is based on the reactivity insertion without any mitigating effects (on the pressure transient) of coolant blowdown through the hole in the vessel head above the rod. The maximum fluid pressure on the components is evaluated for this condition.

3.9.1.1.5 Test Conditions Transients

The following paragraphs describe the following reactor coolant system test conditions transients:

- Primary-side hydrostatic test
- Secondary-side hydrostatic test
- Tube leakage test

3.9.1.1.5.1 Primary-Side Hydrostatic Test

The pressure tests covered by this subsection include both shop and field hydrostatic tests that occur as a result of component or system testing. This hydrostatic test is performed at a water temperature compatible with reactor material ductility requirements and a test pressure of 3107 psig (1.25 times design pressure). In this test, the reactor coolant system is pressurized to 3107 psig coincident with steam generator secondary-side pressure of zero psig. The reactor coolant system is designed for 10 cycles of these hydrostatic tests. The number of cycles is independent of other operating transients.

Additional, lower-pressure hydrostatic tests may be performed to meet the inservice inspection requirements of ASME Code, Section XI, Subarticle IWB-5200. Four such tests are expected. The increase in the fatigue usage factor caused by these tests is covered by the primary-side leakage tests that are considered for design. No additional specification is required.

3.9.1.1.5.2 Secondary-Side Hydrostatic Test

The secondary side of the steam generator is pressurized to 1.25 design pressure, with a minimum water temperature of 120°F. Pressure is maintained on the primary side to avoid overstressing the tubesheet. For design purposes it is assumed that the steam generator will experience 10 cycles of this test. These hydrostatic test cycles are considered in the stress and fatigue analyses.

These tests may be performed either before plant startup or after major repairs or both. The number of cycles is independent of other operating transients.

3.9.1.1.5.3 Tube Leakage Test

It may be necessary to check the steam generator for tube leakage and tube-to-tubesheet leakage. This is done by inspecting the underside (channel-head side) of the tubesheet for water leakage, with the secondary side pressurized. Tube leakage tests are performed during plant cold shutdown.

For these tests, the secondary side of the steam generator is pressurized with water, initially at a relatively low pressure, and the primary system remains depressurized. The underside of the tubesheet is examined for leaks. If any are observed, the secondary side is depressurized and the leaking tube is plugged. The secondary side is then repressurized (to a higher pressure), and the

underside of the tubesheet is again checked for leaks. This process is repeated until the leaks are repaired. The maximum (final) secondary-side test pressure reached is 840 psig.

The total number of tube leakage test cycles is defined as 800 for design purposes. The following is a breakdown of the anticipated number of occurrences at each secondary side test pressure:

Test Pressure (psig)	Number of Occurrences
200	400
400	200
600	120
840	80

During these tests, both the primary and the secondary sides of the steam generators are at ambient temperatures. Neither the primary-side nor secondary-side design pressure is exceeded. The expected secondary-to-primary pressure differential exceeds the design value of 670 psi for some of the test cycles.

3.9.1.2 Computer Programs Used in Analyses

A number of computer programs that are used in the dynamic and static analyses of mechanical loads, stresses, and deformations, and in the hydraulic transient load analyses, of seismic Category I components and supports are listed in Table 3.9-15. A complete list of programs will be included in the ASME Code Design Reports. [*The Combined License applicant will implement the NRC benchmark program using AP1000 specific problems (Reference 20) if a piping analysis computer program other than those used for design certification (PIPESTRESS, GAPPIPE, WECAN, and ANSYS) is used.*]*

The development process, verification, validation, configuration control and error reporting and resolution for computer programs used in these analyses for the AP1000 are completed in compliance with an established quality assurance program. The quality assurance program is described in Chapter 17. The verification conforms to at least one of the following methods:

- Hand calculations
- Alternate verified calculational methods
- Results of other verified programs
- Results obtained from experiments and tests
- Known solutions for similar or standard problems
- Measured and documented plant data
- Confirmed published data and correlations

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- Results of standard programs and benchmarks
- Parametric sensitivity analysis
- Reference to a verification and validation that has been reviewed and accepted by an independent third party

3.9.1.3 Experimental Stress Analysis

For the reactor internals, measured results from prototype plants and various scale model tests are used to validate the analysis of vibrations of reactor vessel internals as discussed in subsection 3.9.2. [*No other experimental stress analysis is used for the AP1000.*]*

3.9.1.4 Considerations for the Evaluation of the Faulted Conditions

Subsection 3.9.3 describes the analytical methods used to evaluate ASME Code, Section III, Class 1 components for Service Level D Conditions (faulted conditions).

3.9.1.5 Module Interaction, Coupling, and Other Issues

Many portions of the systems for the AP1000 are assembled as modules and shipped to the plant as completed or partially completed units. The following provides a discussion of influence of modularization on the structural analysis, inservice inspection, and maintenance in the AP1000.

The modules are constructed using a structural steel framework to support the equipment, pipe, and pipe supports in the module. Piping in the modules is routed and analyzed in the same manner as in a plant built by traditional methods. See subsection 3.7.3 for additional discussion of the structural analysis of modules.

The modules are designed and engineered to provide access for inservice inspection and maintenance activities. Field run pipes and equipment supports do not hinder access for maintenance and inspection.

The quality assurance requirements for the installation and welding of components, piping, supports, and structural elements are the same as in a plant built by traditional methods. The improved access to the parts of the module during fabrication enhances inspection.

3.9.2 Dynamic Testing and Analysis

3.9.2.1 Piping Vibration, Thermal Expansion, and Dynamic Effects

A pre-operational test program as described in Section 14.2 is implemented as required by NB-3622.3, NC-3622, and ND-3611 of the ASME Code, Section III to verify that the piping and piping restraints will withstand dynamic effects due to transients, such as pump trips and valve trips, and that piping vibrations are within acceptable levels. The piping systems to be tested include ASME Code, Section III, Class 1, 2, and 3 systems, high energy systems inside seismic Category I structures, high energy portions of systems whose failure could reduce the functioning of seismic Category I features to an unacceptable level, and the seismic Category I portions of

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

moderate-energy piping systems located outside containment. This includes ASME instrumentation lines up to the first support in each of three orthogonal directions from the process pipe or equipment connection point.

The pre-operational test program for the ASME Code, Section III, Class 1, 2, and 3, and other high-energy or seismic Category I piping systems simulates actual operating modes to demonstrate that the components comprising these systems meet functional design requirements and that piping vibrations are within acceptable levels. The pre-operational testing programs are outlined in subsection 14.2.8. Piping systems are checked in three sequential steps or series of tests and inspections.

Construction acceptance, the first step, entails inspection of components for correct installation. During this phase, pipe and equipment supports are checked for correct assembly and setting. The cold locations of reactor coolant system components, such as steam generators and reactor coolant pumps, are recorded.

During the second step of testing, plant heatup, the plant is heated to normal operating temperatures. During the heatup, systems are observed periodically to verify proper expansion. Expansion data is recorded at the end of heatup.

During the third step of testing, performance testing, systems are operated to check the performance of critical pumps, valves, controls, and auxiliary equipment. This phase of testing includes transient tests performed as outlined in Chapter 14. During this phase of testing, the piping and piping restraints are observed for vibration and expansion response. Automatic safety devices, control devices, and other major equipment are observed for indications of overstress, excess vibration, overheating, and noise. Each system test includes critical valve operation during transient system modes.

The locations in the piping system selected for observation during the testing, and the respective acceptance standards, are provided in the preoperational vibration, thermal expansion, and dynamic effects test program plan.

Provisions are made to verify the operability of essential snubbers by recording hot and cold positions. If vibration during testing exceeds the acceptance standard, corrective measures are taken and the test is performed again to demonstrate adequacy.

3.9.2.1.1 Piping Vibration Details

Piping vibration loadings can be placed in two categories: transient-induced vibrations and steady-state vibrations. The first is a dynamic system response to a transient, time-dependent forcing function, such as fast valve closure. The second is a constant vibration, usually flow-induced. Piping vibration testing and assessment is performed in accordance with ANSI/ASME OM, (Reference 2) Part 3.

Transient Response

Dynamic events falling in this category are anticipated operational occurrences. The systems and the transients included in the preoperational test program are outlined in Section 14.2.

For those types of transients where a time-dependent dynamic analysis is performed on the system, the stresses obtained are combined with system stresses resulting from other operating conditions in according to the criteria identified in subsection 3.9.3.

Details of the program and the pipe monitoring displacement transducers or scratch plates and strain gage or load cells locations, including the criteria for evaluation of data gained, are provided in the test procedures.

Steady-State Vibration

System vibrations resulting from flow disturbances are considered steady-state vibration. Since the exact nature of the flow disturbance is not known prior to pump operation, no analysis is performed. If system vibration is evident during initial operation, the maximum amplitudes are measured and related to alternating stress intensity levels based on the guidance of ANSI/ ASME OM (Reference 2) Part 3.

The AP1000 preoperational vibration monitoring program includes appropriate safety-related instrument lines up to the first support in each of three orthogonal directions from the process pipe or equipment connection point. The acceptance standard is that the maximum alternating stress intensity, S_{alt}, calculated from the measured amplitudes, shall be limited as defined in the following:

A. For ASME Class 1 piping systems:

$$S_{alt} = \frac{C_2 K_2}{Z} M \leq \frac{S_{el}}{\propto}$$

where:

C_2 = secondary stress index as defined in the ASME Code

$\propto$ = allowable stress reduction factor: 1.3 for materials covered by Figure I-9.1; or 1.0 for materials covered by Figure I-9.2.1 or I-9.2.2 of the ASME Code, Section III, Appendices

K_2 = local stress index as defined in the ASME Code

M = maximum zero to peak dynamic moment loading due to vibration only, or in combination with other loads as required by the system design specification

S_{el} = 0.8 S_A, where S_A is the alternating stress at 10^6 cycles from Figure I-9.1; or S_A at 10^{11} cycles from Figure I-9.2.2 of the ASME Code. The influence of temperature on the modulus of elasticity is considered.

Z = section modulus of the pipe

B. For ASME Class 2 and 3 or ANSI B31.1 piping:

$$S_{alt} = \frac{C_2 K_2}{Z} M \leq \frac{S_{el}}{\propto}$$

where:

C_2K_2 = 2i

i = stress intensification factor, as defined in subsection NC and ND of the ASME Code or in ANSI B31.1.

If significant vibration levels are detected during the test program that have not been previously considered in the piping system analysis, consideration is given to modifying the design specification to re-verify applicable code conformance using the measured vibration as input.

If required, additional restraints are provided to reduce stresses to below the acceptance levels.

3.9.2.1.2 Piping Thermal Expansion Program

The piping thermal expansion testing program verifies that the piping systems expand within acceptable limits during heatup and cooldown. Also, this program verifies that the standard component supports (including spring hangers, snubbers, and struts) can accommodate the expansion of the piping within an acceptable range for required modes of operation. Test specifications for thermal expansion testing of piping systems during preoperational and start-up testing will be in accordance with ASME OM Standard, Part 7.

3.9.2.2 Seismic Qualification Testing of Safety-Related Mechanical Equipment

Safety-related mechanical equipment and supports are tested or analyzed to demonstrate functional integrity during and following a postulated safe shutdown earthquake. Equipment that must be active to shut down the plant or mitigate the effects of postulated accidents is analyzed or tested to verify operability. The operability requirements for active valves are discussed more fully in subsection 3.9.3.2.

Section 3.2 lists the equipment classification and seismic category for components and equipment in the AP1000. Table 3.9-12 lists the active valves. The AP1000 has no safety-related active pumps or turbines.

Seismic Category I safety-related equipment is shown to have structural integrity by analysis satisfying the stress criteria applicable to the particular piece of equipment or by tests showing that the equipment retains its structural integrity under the simulated test environment.

Analyses used to verify functional integrity demonstrate that stresses do not exceed the allowables specified for the appropriate loading combinations listed in subsection 3.9.3. Deformations do not exceed those that permit the component to perform its required safety function.

Subsection 3.7.3 describes the methods for seismic subsystem analysis.

Tests used to verify operability demonstrate that the component is not prevented from performing its required safety function during and after the test.

The testing procedures used in the seismic qualification of instrumentation and electrical equipment are discussed in Section 3.10. The operability of active valves includes the operability of the valve operator. Valves and operators are tested for operability as an assembly. Section 3.10 includes a description of operability testing for ASME Code Classes 1, 2, and 3 valves and respective drives, operators, and vital auxiliary equipment. That section includes a description of the seismic operability criteria.

Dynamic testing, analysis, or a combination of the two may be used to qualify safety-related seismic Category I mechanical equipment for a postulated safe shutdown earthquake. The criteria used to decide whether dynamic testing or analysis is used are as follows:

Analysis without Testing

Structural analysis without testing is used if structural integrity alone can verify the intended design function. Equipment which falls into this category includes:

- Piping
- Ductwork
- Tanks and vessels
- Heat exchangers
- Filters
- Passive valves

Dynamic analysis without testing is used to qualify heavy machinery too large to be tested. For active equipment, it is verified that deformations due to seismic loadings do not cause binding of moving parts to the extent that the component cannot perform its required safety function.

Dynamic Testing

Dynamic testing is used for components with mechanisms that must change position in order to perform the required safety function. Section 3.10 discusses the seismic qualification of electrical equipment and combinations of valves and valve operators. Such components include the following:

- Electric motor valve operators
- Valve position sensors
- Similar appurtenances for other active valves

Combinations of Analysis with Testing

Combinations of analysis, static testing, and dynamic testing are used for seismic qualification of complex valves. Section 3.10 discusses the requirements for these combinations for equipment, which includes the following:

- Main steam and main feedwater isolation valves
- Other active valves

3.9.2.3 Dynamic Response Analysis of Reactor Internals under Operational Flow Transients and Steady-State Conditions

The vibration characteristics and behavior due to flow-induced excitation are complex and not readily ascertained by analytical means alone. Assessment of vibrational response is done using a combination of analysis and testing. Comparisons of results obtained from reference plant vibration measurement programs have been used to confirm the validity of scale model tests and other prediction methods as well to confirm the adequacy of reference plant internals regarding flow induced vibration. The flow-induced vibration assessment is documented in WCAP-15949 (Reference 18).

Reactor components are excited by flowing coolant, which causes oscillatory pressures on the surfaces. The integration of these pressures over the applied area provides the forcing functions to be used in the dynamic analysis of the structures. In view of the complexities of the geometries and the random character of the pressure oscillations, a closed form solution of the vibration problem by the integration of the differential equations is not always practical and realistic.

The determination of forcing functions as a direct correlation of pressure oscillations cannot be practically performed independently of the dynamic characteristics of the reactor vessel internals structure. The main objective is to establish the characteristics of the forcing functions that determine the response of the structures.

By studying the dynamic properties of the structure from previous analytical and experimental work, the characteristics of the forcing function are deduced. These studies indicate that the most important forcing functions are flow turbulence and pump-related excitation. The relevance of such excitation depends on factors that include the type and location of components and flow conditions.

The effects of these forcing functions have been studied in tests performed on models and reference plants. These effects will be factored into the analysis models used to evaluate flow-induced vibrations in the AP1000 reactor internals.

The vibration assessment program for the AP1000 reactor internals will determine, prior to testing of the first AP1000, that the internals are not expected to be subject to unacceptable flow-induced vibrations. The assessment is consistent with the guidelines of Regulatory Guide 1.20. Conformance with Regulatory Guide 1.20 is summarized in Section 1.9.1.

The reactor vessel internals in the AP1000 are similar in size and overall configurations to the reactor vessel internals in previous Westinghouse-designed three-loop nuclear power plants.

The original reference plant for Westinghouse three-loop plant reactor internals flow-induced vibration is H. B. Robinson. The results of vibrations testing at H. B. Robinson are reported in WCAP-7765-AR (Reference 3).

Successive design changes that have been incorporated into the AP1000 design since the reference plant tests have also been tested in preoperational plant vibration measurement programs, including the following:

- Inverted hat upper internals and 17x17 guide tubes at DOEL 3 and Sequoyah 1
- XL lower core support structure at DOEL 4
- Elimination of reactor vessel shielding outside the core barrel at PALUEL 1
- Core shroud at Yonggwang 4

These tests confirmed that the internals behaved as expected and that the vibration levels were within allowable values. The vibration testing for 17x17 fuel internals and inverted hat upper internals is reported in WCAP-8766 (Reference 4) and WCAP-8516-P (Reference 5). The vibration testing of three-loop XL type lower core support structure in DOEL 4 is reported in WCAP 10846 (Reference 6). The vibration evaluations of upper and lower internals assemblies for a four-loop XL plant, including reference to the test results in Paluel 1 (four-loop XL type without neutron pads), are reported in WCAP-10865 (Reference 7). The vibration testing of the core shroud lower internals design is reported in Reference 13.

The results of the Doel 3, Doel 4, and Paluel 1 reactor internals vibration test programs will be utilized to perform the vibration assessment of the AP1000 reactor internals. The measured responses from Doel 3 and Doel 4 are adjusted to the higher AP1000 flow rate to support the determination of the expected upper internals and lower internals vibration levels respectively. The velocity through the core is approximately the same as that of Doel 4.

Subsequent operation of numerous plants has further demonstrated the adequacy of the reactor vessel internals regarding flow-induced vibration.

AP1000 includes design features that differ from the design in plants in which the reactor internals have been tested as outlined previously. These design differences include the following:

- The design has four inlet nozzles and two outlet nozzles in a three-loop size reactor vessel with a three-loop size core barrel diameter.

- The AP1000 core barrel overall length is 11 inches longer than that of the standard 3XL design.

- The skirt of the internals support structure is 11-inches longer than the skirt of previous three-loop internals designs.

- The upper support plate has sixty-nine 9.78 inch diameter holes as compared to sixty-one 9.50 inch diameter holes in the previous three-loop design. The plate thickness is identical at 12 inches in both designs.

- The design has a new in-core instrumentation system.
- The structures below the lower core support plate and the height of the lower plenum have been changed. The core barrel restraint elevation is within the radius of the lower head.
- The reactor coolant is moved using a canned motor pump instead of a shaft seal pump.

The vibrations of the upper internals components are well characterized by previous plant testing based on the following: The control assembly guide tubes and support column designs are similar to those in a previously tested plant. With respect to vibratory loads on these components, the higher outlet nozzle velocity of the AP1000 relative to the outlet nozzle velocity of previously tested three-loop plants is expected to be countered by the increased distance of the most highly loaded guide tube from the outlet nozzles.

The AP1000 upper internals design is substantially the same as that measured in the Doel 3 plant and 3XL scale model tests. The AP1000 support column, guide tube and upper support assembly are nearly identical to the components in the 3XL scale model test. There are a greater number of guide tubes and support columns, but as mentioned above, the components expected to be the most highly loaded are farther from the outlet nozzles. Preliminary consideration indicates that the corresponding AP1000 responses will be calculated to be similar to the previous plant responses.

The vibration assessment evaluation will demonstrate that the vibration levels of the AP1000 lower internals are acceptable. Comparison of lower internals design features between the AP1000 and standard 3XL are discussed below.

Although the inlet nozzle and upper downcomer configuration of the AP1000 design differs from that of the 3XL design, the inlet nozzle velocity is less than that of Doel 4.

The core barrel outside diameter and inside diameter and the reactor vessel inside diameter are the same as the tested three-loop plants. The core barrel length is 11 inches longer (~6%). Although the AP1000 coolant velocity at the inlet nozzle is higher, the coolant velocity at the elevation of the lower radial support keys is approximately the same compared to previous three-loop plants. The coolant velocity in the downcomer annulus between the core barrel and the reactor vessel wall is lower in the AP1000 design than in previous three-loop plants because the AP1000 has no thermal shield or neutron pads in the annulus to restrict this flow.

The vibrational response of the core barrel was measured during the Doel 4 reactor internals vibration measurement program. The diameter, length and thickness are nearly identical to the AP1000 core barrel and both utilize the single combined lower core support plate. Comparison of the 4XL scale model to the Paluel plant test results indicate that the removal of the neutron panels has little effect on core barrel vibration.

The core shroud is shorter than the core barrel, has a smaller outer diameter than the core barrel inside diameter, and is more rigidly clamped at its axially supported end, so that it is not expected to have a significant effect on core barrel vibration.

The replacement of the baffle-former structure with the core shroud reduces the stiffness of the lower internals assembly. The AP1000 shell mode amplitudes are estimated to be higher than

three-loop core barrel responses based on scaling the measured responses to the AP1000 reduced core barrel stiffness. The AP1000 shell mode amplitudes are expected to be acceptable.

The AP1000 core barrel and core shroud will be instrumented during the pre-operational testing of the first plant to determine the shell mode and beam mode frequencies and amplitudes.

The in-core instrumentation cables are inside the upper internals support columns and are thus shielded from core plenum coolant flows. The instrumentation cables are subjected to fuel assembly outlet nozzle turbulence. This is judged to be not greater than the inlet nozzle turbulence to which in-core instrumentation thimbles in previous plants were subjected.

One of the changes below the lower core support is the addition of a vortex suppressor. The vortex suppressor design is subject to flow-induced vibrations from coolant flows in the core inlet plenum and by motions of the core barrel. The other significant changes below the lower core support plate are the removal of bottom mounted instrumentation and associated guide tubes and the reduction of the plenum height.

The reactor coolant canned motor pumps of the AP1000, have a higher rotational speed and the same number of impeller blades as in previous plants. An evaluation of pump-induced loads will be included in the vibration assessment. For calculation of pump induced pulsations acting on the AP1000 reactor internals, the pulsation level at the pumps is taken to be the same as the level of previous shaft seal pumps. Since the horsepower of an AP1000 pump is lower than that of a 3XL shaft seal pump, the shaft seal pump pulsation is expected to be a conservative analysis basis for the AP1000.

3.9.2.4 Pre-operational Flow-Induced Vibration Testing of Reactor Internals

The pre-operational vibration test program for the reactor internals of the AP1000 conducted on the first AP1000 is consistent with the guidelines of Regulatory Guide 1.20 for a comprehensive vibration assessment program. Design features that have not previously been tested in the reference plants or subsequent testing are tested to verify the vibration analysis. Conformance with Regulatory Guide 1.20 is summarized in Section 1.9.1.

The program is directed toward confirming the long-term, steady-state vibration response of the reactor internals for operating conditions. The three aspects of this evaluation are the following: a prediction of the vibrations of the reactor internals, a preoperational vibration test program of the internals of the first plant, and a correlation of the analysis and test results.

With respect to the reactor internals preoperational test program, the first AP1000 plant reactor vessel internals are classified as prototype as defined in Regulatory Guide 1.20. The AP1000 reactor vessel internals do not represent a first-of-a-kind or unique design based on the arrangement, design, size, or operating conditions. The units referenced in the subsection 3.9.2.3 as supporting the AP1000 reactor vessel internals design features and configuration have successfully completed vibration assessment programs including vibration measurement programs. These units have subsequently demonstrated extended satisfactory inservice operation.

The reference plant for the AP1000 is H. B. Robinson that has substantially the same size and operating conditions as the AP1000. Structural differences include modifications resulting from

the use of 17x17 fuel, the removal of the thermal shield and the change to the inverted top hat upper internals support assembly. These design changes were incorporated into the Doel 3 and Doel 4 reactor internals as well as the AP1000.

The effects of these design evolutions from the reference plant were shown by instrumented preoperational testing at the Doel 3 (upper internals) and Doel 4 (lower internals) plants. The predicted vibrational responses of the AP1000 reactor internals will be supported by the Doel 3 and 4 vibration measurement programs.

The pre-operational test program of the first AP1000 plant includes a limited vibration measurement program and a pre- and post-hot functional inspection program. This program satisfies the guidelines for a Regulatory Guide 1.20 Prototype Category plant. AP1000 plants subsequent to the first plant will also be subject to the pre- and post-hot functional inspection program. The program for plants subsequent to the first plant satisfies the guidelines for a Non-Prototype Category IV plant.

The acceptance standard for the vibration predictions is established and related to the ASME Code allowables for long term steady-state conditions.

During the hot functional test, the internals are subjected to a total operating time at greater than normal full-flow conditions of at least 240 hours. This provides a cyclic loading of greater than 10^6 cycles on the main structural elements of the internals. In addition, there is some operating time with one, two, or three pumps operating.

Instrumentation is designed and installed to measure the vibration of the internals during hot functional testing. The instrumentation includes devices attached to reactor vessel internals to measure component strains and accelerations.

Since the most notable differences with previously tested designs are in the lower internals, the instrumentation is concentrated on the lower internals. In particular, instrumentation is provided to verify that the incorporation of a core shroud does not cause an unacceptable vibration and to confirm that the flow-induced vibration of the vortex suppression plate is acceptable.

Inspection before and after the hot functional test serves to confirm that the internals are functioning correctly. This inspection is performed on both the first and all subsequent AP1000 plants. When no indications of harmful vibrations or signs of abnormal wear are detected and no apparent structural changes take place, the core support structures are considered to be structurally adequate and sound for operation. If such indications are detected, further evaluation is required.

The testing and inspection plan of the first plant includes features with emphasis on the areas outlined below. The visual inspection plan also applies to plants subsequent to the first.

General

- Major load-bearing elements of the reactor internals relied upon to retain the core structure in place
- The lateral, vertical, and torsional restraints provided within the vessel

- The locking and bolting devices the failure of which could adversely affect the structural integrity of the internals
- The other locations on the reactor internal components that are similar to those that were examined on the reference plant designs
- The inside of the vessel, inspected before and after the hot functional test with the internals removed, to verify that no loose parts or foreign material is present

Lower Internals

- Major girth welds
- Upper core plate aligning pin - bearing surface examined for shadow marks, burnishing, buffing, or scoring, welds inspected for integrity
- Irradiation specimen guide screw locking devices and dowel pins - checked for lockweld integrity
- Radial support key welds
- Secondary core support assembly screw locking devices checked for lock-weld integrity
- Lower radial support keys and inserts - bearing surfaces examined for shadow marks, burnishing, buffing, or scoring, integrity of the lock-welds checked
- Core shroud top plate alignment inserts - bearing surface examined for shadow marks, burnishing, buffing, or scoring - locking devices checked for lock-weld integrity

Upper Internals

- Guide tubes and support columns
- Upper core plate alignment inserts - bearing surface examined for shadow marks, burnishing, buffing, or scoring - locking devices checked for lock-weld integrity
- Guide tube enclosure and card weld integrity

The reactor internals flow-induced vibration measurement program will be conducted during preoperational tests of the first AP1000. The response of the reactor and the internals due to flow-induced vibration will be measured during the hot functional test. Data will be acquired at several temperatures from cold startup to hot standby conditions. The location of the transducers is outlined in Table 3.9-4. The leads for the internally mounted transducers will be routed through the top mounted instrumentation guide tube conduits through special fittings that will be removed following the test.

The expected and acceptable vibration levels and expected natural frequencies will be determined as part of the vibration assessment program. The acceptance standards for the inspection of reactor internals before and after the hot functional testing are the same as required in the shop by the original design drawings and specifications.

3.9.2.5 Dynamic System Analysis of the Reactor Internals Under Faulted Conditions

The reactor internals analysis for Level D Service condition events considers safe shutdown earthquake seismic events and pipe rupture conditions. Subsection 3.9.3 defines the loads and loading combinations considered.

The standard for acceptability in regard to mechanical integrity analyses, are that adequate core cooling and core shutdown must be provided. This implies that the deformation of the reactor internals must be sufficiently small so that the geometry remains substantially intact. Consequently, the limitations established for the internals are concerned with the deflections and stability of the parts in addition to stress criteria to confirm integrity of the components.

The AP1000 design loads for LOCA conditions are based on the use of mechanistic pipe break criteria (see subsection 3.6.3).

3.9.2.5.1 Reactor Internals Analysis Methodology

The evaluation of the reactor internals consists of two major steps. The first step is the three-dimensional response of the reactor internals resulting from the seismic and pipe rupture conditions caused by breaks in the pipe that are not qualified by leak-before-break criteria. The breaks evaluated are those which have the greatest dynamic effect on the reactor internals.

The second step of the evaluation is the component stress evaluations. Maximum stresses and displacements under seismic plus pipe rupture conditions are obtained for the reactor internal components and are combined by the square root of the sum of the squares rule. These maximum stresses and displacements are compared to the allowable values for Level D service conditions.

3.9.2.5.1.1 Dynamic Response of Reactor Pressure Vessel System for Postulated Pipe Rupture

The structural analysis of the reactor vessel system for a postulated pipe rupture considers simultaneous application of the time-history loads that could result from the rupture. The mechanical loads are limited to those due to the movement of the fluid through the reactor internals and a small depressurization effect. Because of the application of mechanistic pipe rupture criteria, evaluation of dynamic effects such as cavity pressurization loads, jet impingement loads, and internal hydraulic pressure transients is limited to those pipe breaks which are not excluded by mechanistic pipe break criteria.

The vessel is restrained by reactor vessel supports beneath four of the reactor vessel nozzles and the reactor coolant loop piping. The reactor coolant loop piping is also supported by the steam generator and steam generator supports.

Analysis of the reactor internals for the loads resulting from a postulated pipe rupture is based on the time-history response of the internals to simultaneously applied forcing functions. The forcing

functions are defined at points in the system where changes in cross section or direction of flow occur in such a way that differential loads are generated during the transient. The dynamic mechanical analysis can employ the displacement method, lumped parameters, and stiffness matrix formulations. Because of the complexity of the system and the components, finite element stress analysis codes are used to provide information at various points.

A digital computer program modeling the blowdown of coolant out the break (see WCAP-8708-P-A, Reference 8), has been developed to calculate local fluid pressure, flow, and density transients that occur in pressurized water reactor coolant systems during a loss of coolant accident. This program is applied to the subcooled, transition, and saturated two-phase blowdown regimes. The program is based on the method of characteristics wherein the resulting set of ordinary differential equations, obtained from the laws of conservation of mass, momentum, and energy are solved numerically, using a fixed mesh in both space and time.

Although spatially, one-dimensional conservation laws are used, the code can be applied to describe three-dimensional system geometries by use of the equivalent piping networks. Such piping networks may contain any number of channels of various diameters, dead ends, branches (with up to six pipes connected to each branch), contractions, expansions, orifices, pumps, and free surfaces (such as in the pressurizer). System losses such as friction, contraction, and expansion, are considered.

The program evaluates the pressure and velocity transients for a maximum of 2400 locations throughout the system. These pressure and velocity transients are stored as a permanent tape file and are made available to a program that uses a detailed geometric description in evaluating the loadings on the reactor internals.

Each reactor component for which calculations are required is designated as an element and assigned an element number. Forces acting upon each of the elements are calculated summing up the effects of the following:

- Pressure differential across the element
- Flow stagnation on and unrecovered orifice losses across the element
- Friction losses along the element

Input to the code, in addition to the pressure and velocity transients, includes the effective area of each element on which the force acts because of the pressure differential across the element, a coefficient to account for flow stagnation and unrecovered orifice losses, and the total area of the element along which the shear forces act.

The pressure waves generated within the reactor are highly dependent on the location and nature of the postulated pipe failure. In general, the more rapid the severance of the pipe and the larger the pipe, the more severe the imposed loading is on the components. With the application of mechanistic pipe rupture and the determination of leak-before-break characteristics in large diameter pipe, the pressure waves are of small consequence compared with the seismic loads.

3.9.2.5.1.2 Reactor Vessel and Internals Modeling

The mathematical model of the reactor pressure vessel is a three-dimensional, nonlinear, finite element model that represents the dynamic characteristics of the reactor vessel and its internals in the six geometric degrees of freedom. The model is developed using a general purpose finite element computer code. The model consists of three concentric, structural submodels connected by nonlinear impact elements and stiffness matrices. The first submodel (Figure 3.9-1) represents the reactor vessel shell and associated components.

The reactor vessel is restrained by the four reactor vessel supports and by the attached primary coolant piping. Each reactor vessel support is modeled by a linear horizontal stiffness and a vertical impact element. The attached piping is represented by a stiffness matrix.

The second submodel (Figure 3.9-2) represents the reactor core barrel, lower support plate, and secondary core support components. This submodel is physically located inside the first and is connected to it by a stiffness matrix at the internals support ledge. Core barrel to vessel shell impact is represented by nonlinear elements at the core barrel flange, core barrel nozzle, and lower radial support locations.

The third and innermost submodel (Figure 3.9-3) represents the upper support plate, guide tubes, support columns, upper core plate, and fuel. The third submodel is connected to the first and second by stiffness matrices and nonlinear elements.

3.9.2.5.2 Analytical Methods

The time-history effects of the internals hydraulic loads and loop mechanical loads are combined and applied simultaneously to the appropriate nodes of the mathematical model of the reactor vessel and internals. The analysis is performed by numerically integrating the differential equations of motion to obtain the transient response.

The output of the analysis includes the displacements of the reactor vessel and the loads in the reactor vessel supports that are combined with other applicable Level D Service condition loads and used to calculate the stresses in the supports.

Also, the reactor vessel displacements are applied as input to the pipe rupture blowdown analysis of the primary loop piping. The resulting loads and stresses in the piping components and supports include both pipe rupture blowdown loads and reactor vessel displacements. Thus, the effect of vessel displacements upon loop response and the effect of loop blowdown upon vessel displacements are both evaluated.

For analysis of a simultaneous seismic event with the intensity of the safe shutdown earthquake (SSE) with the pipe rupture transient, the combined effect is determined by considering the maximum stresses for each condition and combining them with square root of the sum of the squares method.

The system seismic analysis of the reactor vessel and its internals is either performed by a response spectrum analysis method or by a time-history integration method. Both of these analysis techniques are consistent with guidelines in the Standard Review Plan.

For certain systems or components, when time dependent seismic response is desired, the nonlinear time history analysis is used. The seismic time-history analysis technique is essentially the same as that for the pipe rupture analysis, except that in seismic analysis time history accelerations are used as the forcing function. The seismic response is combined with the pipe rupture response, as outlined in subsection 3.9.3, in order to obtain the maximum stresses and deflections.

Reactor internals components are within acceptable stress and deflection limits for the postulated pipe rupture combined with the safe shutdown earthquake condition.

3.9.2.5.3 Control Rod Insertion

During full power plant operation, rod cluster control assemblies and the corresponding drive rod assemblies are held at a fully withdrawn position by their respective control rod drive mechanisms. During certain accident conditions, such as small break loss of coolant accident or a safe shutdown earthquake condition or both, control assemblies are assumed to drop to their fully inserted position. The guide tubes are evaluated to demonstrate the function of the control rods for a break size consistent with use of the leak-before-break criteria.

No credit for the function of the control rods is assumed for large breaks in the safety analyses outlined in Chapter 15. However, for break sizes consistent with use of the leak-before-break criteria, the design of the guide tubes permits control rod insertion at each control rod position.

3.9.2.6 Correlation of Reactor Internals Vibration Tests with the Analytical Results

The results of dynamic analysis of reactor internals have been compared to the results of preoperational testing in reference plants. This comparison verifies that the analytical model used provides appropriate results.

The preoperational vibration test program for the reactor vessel internals of the AP1000 conducted on the first plant, conforms to the intent of the guidelines in Regulatory Guide 1.20 for a comprehensive vibration assessment program. This program includes a correlation of the analysis and test results. This comparison provides additional verification for the analytical model.

3.9.3 ASME Code Classes 1, 2, and 3 Components, Component Supports, and Core Support Structures

Pressure-retaining components, core support structures, and component supports that are safety-related are classified as Class A, B, or C (see subsection 3.2.2) and are constructed according to the rules of the ASME Code, Section III, Division 1. As noted in subsection 3.2.2, Classes A, B, and C mechanical components meet the requirements of Code Classes 1, 2, and 3 respectively.

This subsection discusses the application of the ASME Code to safety-related components and core support structures, the operability of pumps and valves, the design and installation criteria for overpressure protection devices, automatic depressurization devices and the requirements for component supports.

Section 3.8 addresses the loads, loading combinations, and stress limits for structures, including containment.

The ASME Code, Section III requires that a design specification be prepared for ASME Class 1, 2, and 3 components. The specification conforms to and is certified to the requirements of ASME Code, Section III. The Code also requires a design report for safety-related components, to demonstrate that the as-built component meets the requirements of the relevant ASME Design Specification and the applicable ASME Code. The design specifications and design reports will be completed by the Combined License applicant or his agent (see subsection 3.9.8.2). Design specifications for ASME Class 1, 2, and 3 components and piping are prepared utilizing procedures that meet the ASME Code. The design report includes as-built reconciliation.

The as-built reconciliation includes the evaluation of pipe break dynamic loads, changes in support locations, preoperational testing, construction deviations, and completion of the small bore piping analysis.

3.9.3.1 Loading Combinations, Design Transients, and Stress Limits

The integrity of the pressure boundary of safety-related components is provided by the use of the ASME Code. Using the methods and equations in the ASME Code, stress levels in the components and supports are calculated for various load combinations. These load combinations may include the effects of internal pressure, dead weight of the component and insulation, and fluid, thermal expansion, dynamic loads due to seismic motion, and other loads.

To determine if a design is acceptable for the loading combination, the calculated stress levels are compared to acceptance standards in the ASME Code. The acceptance standards in the ASME Code differ depending on the plant operating modes and loads considered. The ASME Code includes a design limit and four service limits (A, B, C, and D) against which to evaluate design conditions and plant and system operating conditions.

The design transients for the AP1000 are defined in subsection 3.9.1. The transients are classified into Level A, B, C, and D Service conditions and test conditions, depending on the expected frequency of occurrence and severity. The description of the transients in subsection 3.9.1 provides the initial plant operating condition and identifies the different component operating conditions. The design transients for Levels A and B are used in the evaluation of cyclic fatigue for the Class 1 components and piping. The effects of seismic events are also included in the evaluation of cyclic fatigue (See subsection 3.9.3.1.2). Level D and up to 25 strong stress cycles of Level C service conditions are not required by the rules of the ASME Code to be included in the fatigue evaluation.

3.9.3.1.1 Seismic Loads and Combinations Including Seismic Loads

Seismic Category I systems and components, including core support structures, are designed for one occurrence of the safe shutdown earthquake which is evaluated as a Service Level D condition for pressure boundary integrity. In addition, systems and components sensitive to fatigue are evaluated for cyclic motion due to earthquakes smaller than the safe shutdown earthquake. Using analysis methods, these effects are considered by inclusion of seismic events with an amplitude not less than one-third of the safe shutdown earthquake amplitude. The number of cycles is

calculated based on IEEE-344-1987 (Reference 21) to provide the equivalent fatigue damage of two full safe shutdown earthquake events with 10 high-stress cycles per event. There are five seismic events with an amplitude equal to one-third of the safe shutdown earthquake response. Each of the one-third safe shutdown earthquake events has 63 high-stress cycles.

ASME Class 1, 2, 3 and CS systems, components and supports are analyzed for the safe shutdown earthquake with other dynamic events. See Tables 3.9-5 and 3.9-8 for load combinations.

The safe shutdown earthquake is analyzed in combination with those operating modes that occur more than 10 percent of the time. Plant conditions combined with safe shutdown earthquake include the following:

- Normal 100-percent power operation. Material properties are based on those at operating temperatures. Water inventories are based on normal operating levels. The in-containment refueling water storage tank is full, the refueling canal is empty, the spent fuel pit, fuel transfer canal, cask loading pit and cask washdown pit are full, and the passive containment cooling system tank is full.

- The safe shutdown earthquake, which is postulated to occur with the plant at normal 100-percent power operation, is assumed to cause nonsafety-related systems, including ac power sources, to be unavailable. A single active failure in the safety-related systems is also postulated.

- The timing and causal relationships that exist between the safe shutdown earthquake and transients such as valve discharge are considered and the events combined when the safe shutdown earthquake is the cause of the transient condition. For analysis of piping systems, the timing and causal relationships are not used to exclude load combinations. The safe shutdown earthquake duration is assumed to be 30 seconds. Nonseismically analyzed structures and components are assumed to be unavailable at the beginning of the safe shutdown earthquake. A single active component failure is assumed to occur at the time the component would be expected to function after the failure of the nonseismic components and structures.

- Nonsafety-related systems are evaluated to confirm that their failure in an earthquake does not jeopardize plant safety.

- A water source is provided for limited fire protection after occurrence of the safe shutdown earthquake. See Section 9.5 for additional information on fire protection.

The AP1000 is also designed for special combinations of events that are not based on the probability of occurrence but are based on past precedents and regulatory guidelines. These special combinations are treated as load combinations, not event sequences. That is, even though the safe shutdown earthquake event does not occur coincident with another event, the loads were combined to provide additional design margin.

- ASME Code components, supports, and support miscellaneous steel for these components are designed for the safe shutdown earthquake combined by the square root of the sum of the

squares method, with short-term dynamic loads due to postulated pipe ruptures. The pipe ruptures included in this combination are those postulated in accordance with subsections 3.6.1 and 3.6.2, but do not include those postulated for evaluation of spray wetting, flooding, and subcompartment pressurization effects, nor those excluded by application of mechanistic pipe rupture criteria. (See subsection 3.6.3.) This combination is used for components and supports that are required to mitigate the effects of the postulated pipe rupture.

- The containment boundary is designed for the safe shutdown earthquake in combination with containment design pressure at containment design temperature.

- The polar crane is designed assuming occurrence of the safe shutdown earthquake during handling of a critical load, such as the reactor vessel head.

3.9.3.1.2 Loads for Class 1 Components, Core Support, and Component Supports

The loads used in the analysis of the Class 1 components, core supports, and component supports are described in the following paragraphs. The loads are listed in Table 3.9-3. Additional information on the loads, stress limits and analysis methods for piping is described in subsection 3.9.3.1.5.

Pressure loading is identified as either design pressure or operating pressure. [*The design pressure is used in minimum wall thickness calculations in accordance with the ASME Code.*]* The term "operating pressure" is associated with Service Levels A, B, C, and D conditions.

[*A dead-weight analysis is performed to meet ASME Code requirements by applying a load equal to the acceleration due to gravity (1.0g) downward on the piping system and components. The piping is assigned a distributed mass or weight as a function of its properties. This method provides a distributed loading to the piping system as a function of the weight of the pipe, insulation, and contained fluid during normal operating conditions.*]*

The analysis of the safe shutdown earthquake loads demonstrates pressure boundary integrity of the Class 1 systems and components. Seismic loads are identified as either seismic inertia loads or seismic anchor motion loads. The seismic inertia loads represent the dynamic portion of the response, and the seismic anchor motion loads represent the static portion. Subsection 3.7.3 describes seismic analysis methods.

Transient dynamic flow and pressure loads resulting from a postulated pipe break are analyzed. Structural consideration of dynamic effects of postulated pipe breaks requires postulation of a finite number of break locations. Section 3.6 defines postulated pipe break locations.

Safety-related piping including the reactor coolant loops, the main steam piping, and reactor coolant system branch lines equal to or larger than six inches nominal pipe size is evaluated with a leak-before-break analysis to verify that there are no locations subject to a sudden, unanticipated rupture of one of these lines. As a result, the piping and components in these systems do not have to be analyzed for the dynamic effects of a break in the pipe when the leak-before-break criteria are satisfied.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

The pipe rupture event considered as a loading is the largest pipe that does not satisfy leak-before-break criteria. The leak-before-break analyses use the acceptance standard of the broad scope rule change to General Design Criterion 4 and NUREG 1061, Volume 3. Subsection 3.6.3 outlines the acceptance standard and approach, including application, methodology, and limits.

Transient dynamic loads are also associated with valve opening and closing. The categories associated with valve operation include automatic depressurization system actuation, fast valve closure, relief valve closed system, relief valve open system, and safety valve discharge. Transient dynamic loads include those due to actuation of the explosive device in squib valves. Components and piping are evaluated for the dynamic response to these transient loads. The relief valve open system (sustained) is evaluated as a static load.

In addition to the loads that apply to the ASME Code Class 1 components, additional miscellaneous loads apply to selected components. These loads are evaluated on a case-by-case basis and are not combined with any other Level C or D Service condition. These miscellaneous loads include the following circumstances.

The reactor coolant pump, steam generator channel head, and connected piping are evaluated for a postulated seized rotor event. For this condition, the rotating mass of the reactor coolant pump is assumed to come to a rapid (but not instantaneous) stop and to transfer the angular momentum through the motor enclosure and pump casing to the steam generator nozzle and reactor coolant piping. The stresses calculated for this event are evaluated using Level D limits for the immediately affected components and supports and using Level B limits for components in the other loop.

For additional information on the specification and analysis of locked rotor loads, see the description in the reactor coolant pump information in subsection 5.4.1.

The passive residual heat removal heat exchanger is evaluated for hydraulic loads from the discharge of steam from the automatic depressurization system valves through the spargers in the in-containment refueling water storage tank. These loads include pressure pulses from the introduction of steam into the tank and collapse of the steam bubbles and the gross movement of water in the tank. The stresses in the passive residual heat removal heat exchanger calculated for this event are evaluated using Level B stress limits.

For additional information on the specification and analysis of hydraulic loads see the description in the passive residual heat removal heat exchanger information in subsection 5.4.14.

Portions of the integrated head package that provide seismic restraint for the control rod drive mechanisms also act as part of the load path for the lifting rig function of the integrated head package. These components are designed and evaluated for heavy load lifting.

For additional information on the design and evaluation of the components of the integrated head package in the load path of the lifting rig, see subsection 3.9.7.

The ASME Code, Section III requires satisfaction of certain requirements relative to design transient conditions for Class 1 components. Subsection 3.9.1.1 summarizes the design transients.

To provide integrity for the reactor coolant system, the transient conditions selected for fatigue evaluation are based on conservative estimates of the magnitude and anticipated frequency of occurrence of the temperature and pressure transients resulting from various plant operation conditions. Generally, only Level A and B service condition design transients are evaluated in the analysis of cyclic fatigue. Up to 25 stress cycles for Level C service conditions may be excluded from cyclic fatigue analysis in conformance with ASME Code, Section III criteria. Any Level C service conditions which are in excess of the 25-cycle limit are evaluated for the effect on cyclic fatigue using Level B criteria. For the evaluation of cyclic fatigue, the cycles included for seismic events are evaluated using Level B criteria and are not excluded from the fatigue evaluation regardless of the size of the stress range considered. The determination of which transient events are included in the 25-cycle exclusion is made separately for each component and line of piping.

The effects of seismic events on the design of components other than piping are considered in one of the following ways. The effects of seismic events are considered by including 20 full cycles of the maximum safe shutdown earthquake stress range in the fatigue analysis. The seismic contribution to the fatigue evaluation is based on five seismic events with an amplitude of one-third the safe shutdown earthquake and 63 cycles per event. The seismic evaluation of piping components is discussed in subsection 3.9.3.1.5.

Thermal Stratification, Cycling, and Striping

Thermal stratification, cycling and striping (TASCS) are phenomena that have resulted in pipe cracking at nuclear power plants. As a result of these incidents, the United States Nuclear Regulatory Commission has issued several bulletins, which are discussed below.

Thermal stratification may occur in piping when flow rates are low and adequate mixing of hot and cold fluid layers does not occur. Thermal cycling due to stratification may occur because of leaking valves or plant operation. Thermal striping is a cyclic mechanism caused by instabilities in the hot-cold fluid interface in stratified fluid during relatively steady flow conditions.

The design of piping and component nozzles in the AP1000 includes provisions to minimize the potential for and the effects of thermal stratification and cycling. [*Piping and component supports are designed and evaluated for the thermal expansion of the piping resulting from potential stratification modes. The evaluation includes consideration of the information on thermal cycling and thermal stratification included in NRC Bulletins 79-13, 88-08, and 88-11, and other applicable design standards.*]*

<u>NRC Bulletin 79-13</u>

Bulletin 79-13 (Reference 16) was issued as a result of a feedwater line cracking incident at Donald C. Cook Unit 2. This bulletin required that inspections of operating plant feedwater lines be performed. This resulted in the discovery of cracks in the feedwater lines of several plants. To provide a uniform approach to address this issue, a Feedwater Line Cracking Owners Group was established. The specific tasks of the Owners Group Program were to evaluate the thermal, hydraulic, structural and environmental conditions which could individually or collectively contribute to feedwater line crack initiation and growth. The Feedwater Line Cracking Owners Group was disbanded in 1981, after the original investigations were completed. The results of this

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

program indicated that the primary cause of the cracking was thermal fatigue loading induced by thermal stratification and high-cycle thermal striping during low flow auxiliary feedwater injection. The mode of failure was concluded to be corrosion fatigue. This information is documented in WCAP-9693 (Reference 17).

The AP1000 steam generators are equipped with separate nozzles for the main feedwater and startup feedwater lines. Analyses of the AP1000 main feedwater nozzles are performed to demonstrate that the applicable requirements of the ASME Section III Code are met. Thermal stratification is prevented in the main feedwater line based on the flow rate limitations within the main feedwater line and the flow control stability for feedwater control. Low feedwater flow duty is provided by the startup feedwater line while higher feedwater flow rates are provided and controlled via the main feedwater line. The switchover from the startup to the main feedwater line occurs above a minimum flow rate to prevent thermal stratification for limiting temperature deviations. Main feedwater control valve positioning during normal operation is the function of the plant control system. The control scheme enhances steam generator level stability and thus reduces potential feedwater thermal stratification resulting from temporary low flow transients.

NRC Bulletin 88-08

Bulletin 88-08, Supplement 1, Supplement 2, and Supplement 3 (Reference 12) were issued following the discovery of cracks in unisolable piping at several nuclear power plants. These cracks were attributed to unanalyzed thermal stresses resulting from isolation valve leakage. This bulletin required that utilities: 1) review systems connected to the reactor coolant system to determine whether unisolable sections of piping connected to the reactor coolant system can be subjected to stresses from temperature stratification or temperature oscillations that could be induced by leaking valves and that were not evaluated in the design analysis of the piping, 2) nondestructively examine the welds, heat-affected zones and high stress locations, including geometric discontinuities and base metal, as appropriate, to provide assurance that there are no existing flaws, and 3) plan and implement a program to provide continuing assurance of piping integrity. This assurance may be provided by designing the system to withstand the stresses from valve leakage, instrumenting the piping to detect adverse temperature distributions and establishing appropriate limits on these temperature distributions, or providing a means that pressure upstream from isolation valves that might leak into the reactor coolant system is monitored and does not exceed reactor coolant system pressure. In addition to leakage into the reactor coolant system, leakage out of the reactor coolant system may also result in adverse thermal stresses as discussed in Supplement 3 of the bulletin.

For adverse stresses from leakage to occur in unisolable piping, three conditions are necessary:

1. A component with the potential for leakage must exist. In most cases, this will be a valve.

2. A pressure differential capable of forcing leakage through the pressure-retaining component must exist. Leakage in unisolable piping sections may be directed toward the reactor coolant system (“inleakage”), or from the reactor coolant system (“outleakage”).

3. A temperature differential between the unisolable piping section and the leakage source sufficient to produce significant stresses in the event of leakage must exist. For cases

involving inleakage, this could result from a cold leakage entering hot sections of unisolable piping. For cases involving outleakage, this could result from hot leakage from the reactor coolant system entering cold sections of unisolable piping.

The criteria used in the evaluation of the AP1000 systems design for susceptibility to adverse stresses from valve leakage are summarized below:

- Single isolation valves can leak, regardless of design except for explosively actuated valves.
- It is generally assumed that two or more closed valves in series are sufficient to limit the amount of leakage to a magnitude which would have a negligible effect on piping integrity.
- Valves which have external operators may leak through the valve seat and packing. In the case of leaking through the packing, additional in-series closed valves may not be beneficial.
- A positive pressure difference should be considered as a possible leak source.
- Cross-leakage is possible between interconnected lines that are attached to different reactor coolant loop pipes and are isolated by single check valves.

[• *Sections of piping systems which have a slope of greater than 45 degrees from the horizontal plane are not subject to thermal stratification, cycling and striping thermal loadings.*

- *Pipe lines, or sections of lines less than or equal to 1-inch nominal size do not require a thermal stratification, cycling and striping evaluation.*]*

The unisolable portions of the following lines connected to the reactor coolant system have been reviewed and are not susceptible to thermal stratification, cycling or striping:

- Direct vessel injection lines from the reactor vessel nozzle up to the accumulator injection valves, core make up injection valves, in-containment refueling water storage tank injection valves, and normal residual heat removal injection valves.
- Core make up lines from the cold legs to the core make up tanks.
- Passive residual heat removal lines from the hot leg to the passive residual heat removal heat exchanger.
- Auxiliary pressurizer spray from the pressurizer spray line to the auxiliary spray check valve.
- Chemical and volume control purification line from the pressurizer spray line to the letdown valve.
- Chemical and volume control purification line from the passive residual heat removal line to the charging valve.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- Pressurizer safety valve lines from the pressurizer to the safety valve.
- Pressurizer spray lines from the cold legs to the pressurizer.
- Automatic depressurization Stage 1, 2, and 3 lines from the pressurizer to the depressurization valves.
- Normal residual heat removal suction lines from the hot legs to the isolation valves.

The unisolable portions of the following lines connected to the reactor coolant system have been reviewed and are determined to be susceptible to thermal stratification, cycling or striping:

- Passive residual heat removal line from the passive residual heat removal heat exchanger to the steam generator channel head.
- Automatic depressurization Stage 4 lines from the hot legs to the Stage 4 depressurization valves.

Analyses of the passive residual heat removal line and the automatic depressurization Stage 4 lines are performed to demonstrate that the applicable requirements of the ASME Section III Code are met. This analysis includes consideration of plant operation and thermal stratification using temperature distributions which are developed from finite element fluid flow and heat transfer analysis.

DCD subsection 3.9.8.2 specifies that the Combined License applicant will have available the final design reports for ASME components, including reconciliation of the as-built piping. This reconciliation includes verification of the thermal cycling and stratification loadings considered in the stress analysis.

NRC Bulletin 88-11

Bulletin 88-11 (Reference 14) was issued after Portland General Electric Company experienced difficulties in setting whip restraint gap sizes on the pressurizer surge line at Trojan plant. The cold gaps were adjusted to design settings several times and were found to be out of specification after each operating cycle. The gap changes were caused by plastic deformation in the surge line piping resulting from excessive thermal loadings. The thermal loadings were determined to be caused by thermal stratification based on monitoring and analysis. Several similar incidents were subsequently discovered in other surge lines, and an industry-wide program to evaluate this phenomena was undertaken by the various PWR owners groups.

The purpose of Bulletin 88-11 was a request to addresses, establish, and implement a program to confirm pressurizer surge line integrity in view of the occurrence of thermal stratification, and to require addressees to inform the NRC staff of the actions taken to resolve this issue.

The actions requested in the bulletin are discussed below, and the manner in which AP1000 addresses the actions, if required, for surge line stratification:

For all licensees of operating PWRs:

Request 1.

The actions included under this heading are not applicable to the AP1000.

For all applicants for PWR Operating Licenses:

Request 2. a)

Before issuance of the low power license, applicants are requested to demonstrate that the pressurizer surge line meets the applicable design codes and other FSAR and regulatory commitments for the licensed life of the plant. This may be accomplished by performing a plant specific or generic bounding analysis. The analysis should include consideration of thermal stratification and thermal striping to ensure that fatigue and stresses are in compliance with applicable code limits. The analysis and hot functional testing should verify that piping thermal deflections result in no adverse consequences, such as contacting the pipe whip restraints. If analysis or test results show Code noncompliance, conduct of all actions specified below is requested.

AP1000 Conformance

Analysis of the AP1000 surge line considers thermal stratification and thermal striping, and demonstrates that the surge line meets applicable code requirements for the licensed life of the plant. Hot functional testing requirements for the AP1000 ensure that piping thermal deflections result in no adverse consequences.

Request 2. b)

Applicants are requested to evaluate operational alternatives or piping modifications needed to reduce fatigue and stresses to acceptable levels.

AP1000 Conformance

Analysis of the AP1000 surge line ensures that stress and fatigue requirements are satisfied, therefore the evaluation of operational alternatives or piping modifications is not required.

Request 2. c)

Applicants are requested to either monitor the surge line for the effects of thermal stratification, beginning with hot functional testing, or obtain data through collective efforts to assess the extent of thermal stratification, thermal striping and piping displacements.

AP1000 Conformance

As part of the Westinghouse Owners Group program on surge line thermal stratification, Westinghouse collected surge line physical design and plant operational data for all domestic Westinghouse PWRs. In addition, Westinghouse collected surge line monitoring data from approximately 30 plants. This experience was used in the development of the AP1000 thermal stratification loadings. As described in the AP1000 Conformance to Request 3 of Bulletin 88-11, monitoring will be performed during hot functional testing and during the first cycle of the first AP1000 plant. This Combined License item is identified in DCD subsection 3.9.8.5. Subsequent monitoring of the AP1000 surge line is not required.

Request 2. d)

Applicants are requested to update stress and fatigue analyses, as necessary, to ensure Code compliance. The analyses should be completed no later than one year after issuance of the low power license.

AP1000 Conformance

Revision of the stress and fatigue analyses is not required for the AP1000 surge line, since the design analysis considers thermal stratification and thermal striping.

Request 3)

Addressees are requested to generate records to document the development and implementation of the program requested by Items 1 or 2, as well as any subsequent corrective actions, and maintain these records in accordance with 10 CFR Part 50, Appendix B and plant procedures.

AP1000 Conformance

AP1000 procedures require documentation and maintenance of records in accordance with 10 CFR Part 50, Appendix B.

A monitoring program will be implemented by the Combined License holder at the first AP1000 to record temperature distributions and thermal displacements of the surge line piping, as well as pertinent plant parameters such as pressurizer temperature and level, hot leg temperature, and reactor coolant pump status. Monitoring will be performed during hot functional testing and during the first fuel cycle. The resulting monitoring data will be evaluated to show that it is within the bounds of the analytical temperature distributions and displacements.

Other Applications

Thermal stratification in the reactor coolant loops resulting from actuation of passive safety features is evaluated as a design transient. Stratification effects due to both Level B and Level D service conditions are considered. The criteria used in the evaluation of the stress in the loop piping due to stratification is the same as that applicable for other Level B and Level D service conditions.

3.9.3.1.3 ASME Code Class 1 Components and Supports and Class CS Core Support Loading Combinations and Stress Limits

Tables 3.9-5 and 3.9-8 list loading combinations for ASME Class 1 components and component supports and Class CS core support structures. Table 3.9-9 lists the stress limits for these components. Table 3.9-3 lists the loads included in the loading combinations.

The stress limits for Service Level D that allow inelastic deformation are supplemented with the requirements of "Rules for Evaluation of Service Loadings with Level D Service Limits," Appendix F of ASME Code, Section III. The limits and rules of Appendix F confirm that pressure boundary integrity and core support structural integrity are maintained but do not confirm operability. The limits and rules of Appendix F do not apply to the portion of the component or support in which the failure has been postulated. Subsection 3.9.1 provides a discussion of design transients used in the analysis of cyclic fatigue.

The structural stress analyses performed on the ASME Code Class 1 components and supports and Class CS core support structures consider the loadings specified, as shown in Table 3.9-3. These loads result from thermal expansion, pressure, weight, earthquake, pipe rupture, and plant operational thermal and pressure transients. Dynamic effects of pipe rupture, including the loss of coolant accident, are not included in loading combinations when the leak-before-break criteria are satisfied. The methods and acceptance standard for leak-before-break analyses are described in subsection 3.6.3.

[*The combination of safe shutdown earthquake plus pipe rupture*]* (those breaks not excluded by mechanistic pipe break criteria) [*loads by square-root-sum-of the squares is considered.*]* This loading combination is evaluated for ASME Code components and piping that are required to mitigate the effects of the postulated pipe rupture and the supports for those components and piping.

The dynamic effects of pipe rupture that are combined with safe shutdown earthquake in loading combinations are those for lines for which the leak-before-break criteria are not satisfied. [*When the safe shutdown earthquake event is determined mechanistically to result in concurrent transient loads due to relief valve or safety valve discharge in ASME Code Class 1, 2, or 3 systems, the maximum response due to the safe shutdown earthquake is combined with the maximum response due to the valve opening discharge transient. The responses are combined using the square-root-sum-of-the-squares method.*]* Concurrent sustained loads due to open system relief valve discharge are combined with safe shutdown earthquake by absolute sum.

3.9.3.1.4 Analysis of Reactor Coolant Loop Piping

The reactor coolant loop and support system model consists of the primary loop piping (hot and cold legs), the connecting components (reactor vessel, steam generator, and reactor coolant pump) and the components supports (steam generator and reactor vessel).

The integrated reactor coolant loop and supports system model is the basic system model used to compute loadings on components, component supports, and piping. The system model includes the stiffness and mass characteristics of the reactor coolant loop piping and components, the stiffness of supports, and the stiffnesses of auxiliary line piping affecting the system. This model

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

is used to determine the static and dynamic loads on the primary loop piping and the component supports and the interfacing loads on the connecting components.

The analysis of the connecting components is based on more detailed models of the steam generator, reactor vessel, and reactor coolant pump. Appendix 3C describes the analytical methods used in evaluating the piping of the reactor coolant loops.

[*The primary loop analysis for the safe shutdown earthquake uses the time-history integration or response spectra methods for seismic dynamic analysis.*]* Appendix 3C provides a description of the model.

The model used in the static analysis is modified for the dynamic analysis by including the mass characteristics of the piping and equipment. [*In the time-history seismic analysis, the containment internals structure is included in the system coupled model.*]* The effect of the equipment motion on the reactor coolant loop and supports system is obtained by modeling the mass and the stiffness characteristics of the equipment in the overall system model.

The main loop piping and the surge line satisfy the leak-before-break requirements for the elimination of nonmechanistic pipe breaks. See subsection 3.6.3 for a description of the evaluation of piping for leak-before-break requirements. Reactor coolant system piping of 6-inch nominal pipe size or larger is evaluated for leak-before-break characteristics. The reactor coolant loop piping is evaluated for loads due to a break in the largest connected pipe that does not meet leak-before-break requirements. [*The primary loop analysis for pipe breaks uses time-history integration or equivalent static analysis to determine the structural response due to jet impingement loads, thrust loads, and subcompartment pressure loads.*]*

Operating transients in a nuclear power plant cause thermal or pressure fluctuations or both in the reactor coolant fluid. The thermal transients cause time-varying temperature distributions across the pipe wall. The transients as summarized in subsection 3.9.1.1 are used to define the fluctuations in plant parameters.

A one-dimensional finite difference heat transfer program is generally used to solve the thermal transient problem. The pipe is represented by many elements through the thickness of the pipe. The convective heat-transfer coefficient used in this program represents the time-varying heat transfer due to free and forced convection. The outer surface is assumed to be adiabatic, while the inner surface boundary experiences the temperature of the coolant fluid.

Fluctuations in the temperature of the coolant fluid produce a temperature distribution through the pipe wall thickness that varies with time. The average through-wall temperature, T_A, is calculated by integrating the temperature distribution across the wall. This integration is performed over each time step so that T_A is determined as a function of time.

A load-set is defined as a set of pressure loads, moment loads, and through-wall thermal effects at a given location and time in each transient. The through-wall thermal effects are functions of time and can be subdivided into four parts:

- Average temperature (T_A), which is the average temperature through-wall of the pipe that contributes to general expansion loads

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- Radial linear thermal gradient, which contributes to the through-wall bending moment (ΔT_1)

- Radial nonlinear thermal gradient (ΔT_2), which contributes to a peak stress associated with shearing of the surface

- Discontinuity temperature (T_A - T_B) which represents the difference in average temperature at the cross sections on each side of a discontinuity

Each transient is described by at least two load-sets representing the maximum and minimum stress states during each transient. The construction of the load-sets is accomplished by combining the following to yield the maximum (minimum) stress state during each transient.

- ΔT_1
- ΔT_2
- $\alpha_A T_A - \alpha_B T_B$
- Moment loads due to T_A
- Pressure loads

This procedure produces at least twice as many load-sets as transients for each point.

For the possible load-set combinations, the primary-plus-secondary and peak stress intensities, fatigue reduction factors (K_e), and cumulative usage factors (U) are calculated.

The combination of load-sets yielding the highest alternating stress intensity range is first used to calculate the incremental usage factor. The next most severe combination is then determined, and the incremental usage factor is calculated. This procedure is repeated until the combinations having an allowable number of cycles less than 10^{11} are formed. The total cumulative usage factor at a point is the summation of the incremental usage factors.

3.9.3.1.5 ASME Classes 1, 2, and 3 Piping

The loads for ASME Code Classes 1, 2, and 3 piping are included in the loads listed in Table 3.9-3. [*Tables 3.9-5, 3.9-6, and 3.9-9 list the loading combinations and stress limits for Class 1 piping. Tables 3.9-5, 3.9-7, and 3.9-10 list the loading combinations and stress limits for Class 2 and 3 piping.*

Piping systems are designed and analyzed for Levels A, B, and C service conditions, and corresponding service level requirements to the rules of the ASME Code, Section III. The analysis or test methods and associated stress or load allowable limits that are used in evaluation of Level D service conditions are those that are defined in Appendix F of the ASME Code, Section III. Inelastic analysis methods are not used.]*

Subsection 3.7.3 summarizes seismic analysis methods and criteria. Subsection 3.6.2 summarizes pipe break analysis methods.

The supports are represented by stiffness matrices in the system model for the dynamic analysis. Alternate methods for support stiffnesses representation is provided in subsection 3.9.3.4. Shock

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

suppressors that resist rapid motions and limit stop supports with gaps are also included in the analysis. The solution for the seismic disturbance uses the response spectra method. This method uses the lumped mass technique, linear elastic properties, and the principle of modal superposition. Alternatively, the time-history method may be used for the solution of the seismic disturbance.

The total response obtained from the seismic analysis consists of two parts: the inertia response of the piping system and the response from differential anchor motions (see subsection 3.7.3). The stresses resulting from the anchor motions are considered to be secondary and are evaluated to the limits in Table 3.9-6 and 3.9-7.

The mathematical models used in the seismic analyses of the Class 1, 2, and 3 piping systems lines are also used for pipe rupture effect analysis. To obtain the dynamic solution for auxiliary lines with active valves, the time-history deflections from the analysis of the reactor coolant loop are applied at nozzle connections. For other lines that must maintain structural integrity or that have no active valves, the motion of the reactor coolant loop is applied statically.

[*The functional capability requirements for ASME piping systems that must maintain an adequate fluid flow path to mitigate a Level C or Level D plant event are shown in Table 3.9-11.*]* These requirements are based on Reference 19.

Thermal analysis is required to obtain the stresses and loadings above the stress free state of the system. The stress free state of a piping system is defined as a temperature of 70°F. [*If the piping system operating temperature is 150°F or less, no thermal expansion analysis is required. If the piping system does not contain at least one 90-degree bend, then thermal expansion analysis is required.*]* This type of layout is avoided when practical. [*The thermal anchor displacements are also considered as negligible if they are 1/16 inches or less.*]* This is consistent with the practice that 1/16-inch of gap is allowed at a pipe support.

[*A thermal transient heat transfer analysis is performed for each different piping component on the Class 1 branch lines larger than 1-inch nominal diameter.*]* The following discussion on the evaluation of cyclic fatigue is not applicable to Class 2 and 3 pipe.

[*The Level A and B service condition and test condition transients identified in subsection 3.9.1.1 are included in the fatigue evaluation. For each thermal transient, two load-sets are defined representing the maximum and minimum stress states for that transient. The effects of seismic events on the design of piping are considered in one of the following ways. The effects of seismic events are considered by including 20 full cycles of the maximum safe shutdown earthquake stress range in the fatigue analysis. Alternatively, the seismic contribution to the fatigue evaluation is based on five seismic events with an amplitude of one-third the safe shutdown earthquake and 63 cycles per event.*

The primary-plus-secondary and peak stress intensity ranges, fatigue reduction factors, and cumulative usage factors are calculated for the possible load-set combinations. It is conservatively assumed that the transients can occur in any sequence, thus resulting in the most conservative and restrictive combinations of transients.]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

The combination of load-sets yielding the highest alternating stress intensity range is determined, and the incremental usage factor is calculated. Likewise, the next most severe combination is then determined, and the incremental usage factor is calculated. This procedure is repeated until the combinations having an allowable cycle of less than 10^{11} are formed. The total cumulative usage factor at a point is the summation of the incremental usage factors.

3.9.3.1.6 Analysis of Primary Components and Class 1 Valves and Auxiliary Components

Primary components that serve as part of the pressure boundary in the reactor coolant loop include the steam generators, reactor coolant pumps, pressurizer, and reactor vessel. This equipment is AP1000 Equipment Class A. The pressure boundary meets the requirements of ASME Code, Section III. This equipment is evaluated for the loading combinations outlined in Table 3.9-5. The equipment is analyzed for the normal loads of weight, pressure, and temperature; mechanical transients of safe shutdown earthquake and auxiliary line pipe ruptures; and pressure and temperature transients are outlined in subsection 3.9.1.1.

The results of the reactor coolant loop analysis and other ASME Code, Section III, Class 1, 2, and 3 piping analyses are used to determine the seismic loads acting on the equipment nozzles and the support and component interface locations. Subsection 3.7.3 summarizes seismic analysis methods and criteria used for analysis of primary components. The results of the reactor coolant loop analysis, other ASME Code, Section III, Class 1, 2, and 3 piping analyses, and the reactor vessel system analysis are used to determine pipe break loads on the equipment nozzles and the support component interface locations for those lines that do not meet the leak-before-break requirements.

Section 3.6 summarizes the pipe break analysis methods used to determine pipe rupture loads for the ASME Code Class 1 components.

Seismic analyses are performed individually for the reactor coolant pump, pressurizer, and steam generator. Detailed and complex dynamic models are used for the dynamic analyses. Seismic analyses for the steam generator, reactor coolant pump, and pressurizer are performed using 4 percent damping for the safe shutdown earthquake.

The reactor pressure vessel is seismically qualified in accordance with ASME Code, Section III. The loadings used in the analysis are based on loads generated by a dynamic system analysis.

Auxiliary equipment that serves as part of the reactor coolant system pressure boundary includes ASME Code, Section III, Class 1 valves, core makeup tanks, and passive residual heat removal heat exchanger. Components and valves which form part of the reactor coolant system pressure boundary are designed and analyzed according to the appropriate portions of the ASME Code, Section III. This equipment is evaluated for the loading combinations and stress limits in Tables 3.9-5 and 3.9-9. The operability criteria for these valves are described in subsection 3.9.3.2.

Valves in sample and instrument lines connected to the reactor coolant system are not considered to be AP1000 Equipment Class A nor ASME Class 1. This is because the nozzles where the lines connect to the primary system piping include an orifice with a 3/8-inch hole. This hole restricts the flow so that loss through a severance of one of these lines can be made up by normal charging flow. These small lines are seismically analyzed as described in subsection 3.7.3.

3.9.3.1.7 ASME Code Class 2 and 3 Components

Table 3.9-3 lists the loads for ASME Code Class 2 and 3 components. Table 3.9-5 provides the loading combinations. The loading conditions for ASME Class 2 and 3 piping are presented in Table 3.9-3. Table 3.9-10 presents the stress limits for the various service levels. Functional capability requirements are presented in Table 3.9-11. Subsection 3.7.3 summarizes the seismic analysis methods and criteria for these components. The pipe break analysis methods are summarized in subsection 3.6.2. Analysis methods for Class 2 and 3 piping are summarized in subsection 3.9.3.1.5.

The allowable stress limits established for the components are low enough so that breach of the pressure-retaining boundary does not occur. Active valves requirements are further described in subsection 3.9.3.2.

3.9.3.2 Pump and Valve Operability Assurance

The design and service limits specified by the ASME Code, Section III are established to confirm the pressure-retaining or support function of the ASME Code-class component. To assess the functional capability of required components to operate, additional criteria and considerations, including collapse and deflection limits, are developed.

3.9.3.2.1 Pump Operability

There are no active pumps relied upon to perform a safety-related function in the AP1000.

3.9.3.2.2 Valve Operability

Active valves are those whose operability is relied upon to perform a safety-related function during transients or events considered in the respective operating condition categories. Inactive components are those whose operability is not relied upon to perform a safety-related function for the various transients and plant conditions. Table 3.9-12 lists the active valves.

Table 3.9-9 provides the stress limits used for active Class 1 valves. Table 3.9-10 provides the stress limits used for active Class 2 and Class 3 valves.

Active valves are subjected to a series of tests and inspections prior to service and during the plant life. These tests and inspections along with controls on maintenance and operation provide appropriate reliability of the valve for the design life objective of the plant.

Prior to installation, the following tests, as appropriate to the function and mission of the valve, are performed: shell hydrostatic test, backseat and main seat leakage tests, disc hydrostatic tests, and operational tests to verify that the valve opens and closes.

Cold hydro tests, hot functional tests, periodic inservice inspections, and periodic inservice operations are performed in situ to verify the functional capability of the valve.

Refer to Section 3.11 for the operability qualification of motor operators for the environmental conditions.

For active valves with extended structures, an analysis of the extended structure is performed for equivalent static seismic safe shutdown earthquake loads applied at the center of gravity of the extended structure.

In addition to these tests and analyses, a representative number of valves of each design type are tested for verification of operability during a simulated Service Level D (safe shutdown earthquake) condition event by demonstrating operational capabilities within the specified limits. Valve sizes that cover the range of sizes in service are tested.

When seismic qualification is based on dynamic or equivalent static load testing for structures, systems or subsystems that contain mechanisms that must change position in order to function, operability testing is performed for the safe shutdown earthquake preceded by one or more earthquakes. The number of preceding earthquakes is calculated based on IEEE-344-1987 to provide the equivalent fatigue damage of one safe shutdown earthquake event.

The seismic qualification testing procedures for valve operability testing are as follows: The valve is mounted in a manner that will conservatively represent typical valve installations. The valve includes the operator, accessory solenoid valves, and position sensors when attached to the valve in service.

The operability of the valve during a Service Level D condition is demonstrated by satisfying the following criteria:

- A static load or loads equivalent to those resulting from the accelerations due to Service Level D conditions is applied to the extended structure center of gravity so that the resulting deflection is in the nearest direction of the extended structure. The design pressure of the valve is applied to the valve during the static deflection tests.

- The valve is cycled while in the deflected position. The valve must function within the specified operating time limits while subject to design pressure.

- Electrical motor operators, position sensors, and pilot solenoid valves necessary for operation are qualified in accordance with IEEE seismic qualification standards. Section 3.10 describes the methods and criteria used to qualify electrical equipment.

Active valves that do not have an extended structure, such as check valves and safety valves, are considered separately.

Check valves are characteristically simple in design, and their operation is not affected by seismic accelerations or the maximum applied nozzle loads. The check valve design is compact, and there are no extended structures or masses whose motion could cause distortions that could restrict operation of the valve. These valves are designed such that if structural integrity is maintained, the valve operability is maintained. In addition to these design considerations, the check valves also undergo the following: in-shop hydrostatic test, in-shop seat leakage test, and periodic in situ valve testing and inspection.

Pressurizer and main steam safety valves are qualified for operability in the same manner as valves with extended structures. The qualification methods include analysis of the bonnet for equivalent

static safe shutdown earthquake loads, in shop hydrostatic and seat leakage tests, and periodic in situ valve inspection.

To verify analysis methods, representative safety valves are tested. This test is described as follows:

- The safety valve is mounted to represent the specified installation.
- The valve body is pressurized to its normal system pressure.
- A static load representing the Service Level D condition load is applied to the top of the valve bonnet in the weakest direction of the extended structure.
- The pressure is increased until the valve actuates.
- Actuation of the valve at its setpoint provides for operability during the Service Level D condition load.

Using these methods, the active valves in the system are qualified for operability during a Service Level D condition event. These methods conservatively simulate the seismic event, and confirm that the active valves perform their safety-related function when necessary.

3.9.3.3 Design and Installation Criteria of Class 1, 2, and 3 Pressure Relieving Devices

[*The design of pressure relieving valves comply with the requirements of ASME Code, Section III, Appendix O, "Rules for the Design of Safety Valve Installations."*]* When there is more than one valve on the same run of pipe, the sequence of valve openings is based on the anticipated sequence of valve opening. This sequence is determined by the set point pressures or control system logic. The applicable stress limits are satisfied for the components in the piping run and connecting systems including supports. The reaction forces and moments are based on a dynamic load factor of 2.0 unless a dynamic structural analysis is performed to calculate these forces and moments.

3.9.3.3.1 Pressure Relief Devices and Automatic Depressurization Valves Connected to the Pressurizer

The pressurizer safety valves provide overpressure protection for the reactor coolant system. The safety valves connected to the pressurizer are the only ASME Code, Section III, Class 1 pressure relief valves in the AP1000. The automatic depressurization system valves that provide a means to reduce reactor coolant system pressure to allow the passive core cooling system to fully function are not designed to provide overpressure protection and are not classified as pressure relief devices.

The safety valves and the first three stages of the automatic depressurization valves are mounted in and supported by the pressurizer safety and relief valve (PSARV) module located above the pressurizer. The valves are connected to two piping manifolds that are connected to two nozzles located in the pressurizer upper head. [*The spring loaded safety valves are designed to prevent system pressure from exceeding design pressure by more than ten percent.*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

If the pressure exceeds the setpoint of the safety valve, the valve opens and steam is discharged through a rupture disk to the containment atmosphere. The pressurizer volume is sized so that opening of the safety valve is not required for any Level A or B service condition transient. The connecting pipe between the pressurizer and safety valves does not include a loop seal. The safety valves seal against the steam and any noncondensible gas in the upper portion of the pressurizer.

The valves for the automatic depressurization system open when required for the passive safety injection system. The motor-operated automatic depressurization valves open in sequence to reduce reactor coolant system pressure when required to allow stored water sources to cool the core. The valves open in stages as required by the controls for the automatic depressurization system. The automatic depressurization system valves open more slowly than do the safety valves. The operation of the automatic depressurization system is outlined in subsection 5.4.6 and Section 6.3. For the three stages that are connected to the pressurizer, the valves discharge into the in-containment refueling water storage tank through a sparger. The piping connection of the automatic depressurization system valves to the pressurizer contain loop seals.

The valve opening generates transient thrust forces at each change in flow direction or area. The analysis of the piping system and support considers the transient forces associated with valve opening.

For each pressurizer safety and automatic depressurization system piping system, an analytical hydraulic model is developed. The piping from the pressurizer nozzle to the rupture disk and in-containment refueling water storage tank sparger is modeled as a series of single pipes. The pressurizer is modeled as a reservoir that contains steam at constant pressure and at constant temperature. Fluid acceleration inside the pipe generates reaction forces on the segments of the line that are bounded at either end by an elbow or bend. Reaction forces resulting from fluid pressure and momentum variations are calculated. These forces are defined in terms of the fluid properties for the transient hydraulic analysis.

3.9.3.3.2 Pressure Relief Devices for Class 2 Systems and Components

Pressure relieving devices for ASME Code, Section III, Class 2 systems include the safety valves and power operated relief valves on the steam line and the relief valve on the containment isolation portion of the normal residual heat removal system.

The design and analysis requirements for the safety and relief valves and discharge piping for the steam line are described in subsection 10.3.2.

In addition to providing overpressure protection for the normal residual heat removal system, the relief valve also provides low temperature overpressure protection for the reactor coolant system. The location and connection for the valve on the residual heat removal system are discussed in subsection 5.4.7.

3.9.3.3.3 Design and Analysis Requirements for Pressure Relieving Devices

The design of pressure-relieving devices can be generally grouped in two categories: open discharge and closed discharge.

Open Discharge

An open discharge is characterized by a relief or safety valve discharging to the atmosphere or to a vent stack open to the atmosphere. [*The design and analysis of open discharge valve stations includes the following considerations:*

- *Stresses in the valve header, the valve inlet piping, and local stresses in the header-to-valve inlet piping junction due to thermal effects, internal pressure, seismic loads, and thrust loads are considered.*
- *Thrust forces include both pressure and momentum effects.*
- *Where more than one safety or relief valve is installed on the same pipe run, valve spacing requirements are as specified in the ASME Code.*
- *The minimum moments to be used in stress calculations are those specified in the ASME Code.*
- *The effects of the valve discharge on piping connected to the valve header are considered.*
- *The reaction forces and moments used in stress calculations include the effects of a dynamic load factor (DLF), or are the maximum instantaneous values obtained from a time-history structural analysis.*]*

Closed Discharge

The closed discharge system is characterized by piping between the valve and a tank or some other terminal end. Under steady-state conditions, there are no net unbalanced forces. [*The initial transient response and resulting stresses are determined using either a time-history computer solution*]* or a conservative equivalent static solution. [*In calculating initial transient forces, pressure and momentum terms as well as water slug effects are included.*]*

3.9.3.4 Component and Piping Supports

[*The supports for ASME Code, Section III, Class 1, 2, and 3 components including pipe supports satisfy the requirements of the ASME Code, Section III, Subsection NF.*]* The welded connections of ASTM A500 Grade B tube steel members satisfy the requirements of the Structural Welding Code, ANSI/AWS D1.1, Section 10. [*The boundary between the supports and the building structure is based on the rules found in Subsection NF.*]* Table 3.9-3 presents the loading conditions. [*Table 3.9-8 summarizes the load combinations. The stress limits are presented in Tables 3.9-9 and 3.9-10 for the various service levels.*]*

The criteria of Appendix F of the ASME Code Section III is used for the evaluation of Level D service conditions. When supports for components not built to ASME Code, Section III criteria are evaluated for the effect of Level D service conditions, the allowable stress levels are based on tests or accepted industry standards comparable to those in Appendix F of ASME Code, Section III.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

In order to provide for operability of active equipment, including valves, ASME limits for Service Level C loadings are met for the supports of these items.

Dynamic loads for components loaded in the elastic range are calculated using dynamic load factors, time-history analysis, or any other method that accounts for elastic behavior of the component. A component is assumed to be in the elastic range if yielding across a section does not occur. Local yielding due to stress concentration is assumed not to affect the validity of the assumptions of elastic behavior. The stress allowables of Appendix F for elastically analyzed components are used for Code components. Inelastic stress analysis is not used.

The stiffness of the pipe support miscellaneous steel is controlled by one of the following methods so that component nozzle loads are not adversely affected by support deformation:

[*Pipe support miscellaneous steel deflections are limited for dynamic loading to 1/8 inch in each restrained direction. The dynamic loading combination considered are those in Table 3.9-8 associated with Level D service limits.*]* These deflections are defined with respect to the structure to which the miscellaneous steel is attached. These deflection limits, provide adequate stiffness for seismic analysis and are small enough so that nozzle loads are not affected by pipe support deformation. In this case, the pipe support and miscellaneous steel are represented by a generic stiffness value in the piping system analysis. Rigid stiffness values are used for fabricated supports, and vendor stiffness values are used for standard supports such as snubbers, and rigid gapped supports. [*The mass of the pipe support miscellaneous steel is evaluated as a self-weight excitation loading on the steel and the structures supporting the steel.*]*

[*Alternatively, if the deflections for dynamic loading exceeds 1/8 inches, the pipe support and miscellaneous steel are represented by calculated stiffness values in the piping system analysis.*]*

Use of baseplates with concrete expansion anchors is minimized in the AP1000. Concrete expansion anchors may be used for pipe supports. For these pipe support baseplate designs, the baseplate flexibility requirements of IE Bulletin 79-02, Revision 2, dated November 8, 1979 are met by accounting for the baseplate flexibility in the calculation of anchor bolt loads. Supplemental requirements for fastening anchor bolts to concrete are outlined in subsection 3.8.4.5.1.

[*Friction forces induced by the pipe on the support must be considered in the analysis of sliding type supports, such as guides or box supports, when the resultant unrestrained thermal motion is greater than 1/16 inch. The friction force is equal to the coefficient of friction times the pipe load, and acts in the direction of pipe movement. A coefficient of friction of 0.35 for steel-on-steel sliding surfaces shall be used. If a self-lubricated bearing plate is used, a 0.15 coefficient of friction shall be used. The pipe load from which the friction force is developed includes only deadweight and thermal loads. The friction force can not be greater than the product of the pipe movement and the stiffness of the pipe support in the direction of movement.*]*

Small gaps are provided for frame type supports built around the pipe. These gaps allow for radial thermal expansion of the pipe as well as allowing for pipe rotation. The minimum gap (total of opposing sides) between the pipe and the support is equal to the diametral expansion of the pipe

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

due to temperature and pressure. [*The maximum gap is equal to the diametral expansion of the pipe due to temperature and pressure plus 1/8 inch.*]*

For standard component pipe supports, the manufacturer's functional limitations for example, travel limits and sway angles, should be followed. This criterion is applicable to limit stops, snubbers, rods, hangers and sway struts. Snubber settings should be chosen such that pipe movement occurs over the mid range of the snubber travel. Some margin should be provided between the expected pipe movement and the maximum or minimum snubber-stroke to accommodate construction tolerance.

3.9.3.4.1 ASME Code Class 1 Component Supports

The load combinations and allowable stresses for ASME Code Class 1 component supports are given in Tables 3.9-8 and 3.9-9.

3.9.3.4.1.1 Class 1 Component Supports Models and Methods

The static and dynamic structural analyses employ the matrix method and normal mode theory for the solution of lumped-parameter, multimass structural models. The equipment support structure models are dual-purpose, since they represent quantitatively the elastic restraints that the supports impose upon the component, and represent the individual support member stresses due to the forces imposed upon the supports by the component.

A description of the supports for the reactor pressure vessel, steam generator, and pressurizer is found in subsection 5.4.10. The supports are modeled using elements such as beams, plates, and springs where applicable.

The reactor vessel supports are located at each of the four inlet nozzles and are modeled using a finite element computer program.

Steam generator supports include a column support below the steam generator, a lateral support attached to the top of the column support, a lateral support transverse to the hot leg attached to the secondary shell at the operating floor, and a lateral support (snubbers) parallel to the hot leg attached to the secondary shell at the top of the steam generator compartment, and are normally modeled as linear or nonlinear springs. The reactor coolant pump is supported by the connection to the steam generator and does not have separate supports.

The pressurizer is supported by four columns. Each core makeup tank is supported by eight columns.

The passive residual heat removal heat exchanger is supported by the in-containment refueling water storage tank. The channel heads are outside of the tank and the tubesheets are connected to the tank wall. The tubes are inside the tank, exposed to fluid motion and supported by a structure resting on the floor of the tank and attached to the tank wall.

For each operating condition, the loads (obtained from the reactor coolant loop analysis or the analysis of the component) acting on the reactor pressure vessel, steam generator, and pressurizer supports are appropriately combined. The adequacy of each member of the supports, is verified by

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

solving the stress and interaction equations of ASME Code, Section III, Subsection NF and Appendix F. The adequacy of the reactor pressure vessel support structure is verified using a finite element computer program and comparing the resultant stresses to the criteria given in ASME Code, Section III, Subsection NF and Appendix F.

The test load method given in Appendix F is an acceptable method of qualifying components in lieu of satisfying the stress/load limits established for the component analysis. The test load method is not used in the AP1000 to qualify supports of components built to ASME Code, Section III requirements.

3.9.3.4.2 ASME Code Class 2 and 3 Supports

[*Class 2 and 3 component supports are designed and analyzed for design condition, and Level A, B, C, and D service conditions to the rules and requirements of ASME Section III, Subsection NF, and Appendix F.*]* The analyses or test methods and associated stress or load allowable limits that are used in the evaluation of linear supports for Level D service conditions are those defined in the ASME Code. Plate and shell type supports satisfy the Level D service condition limits provided in Appendix F of the ASME Code, Section III. Tables 3.9-8 and 3.9-10 outline the allowable stresses and loading combinations for ASME Code, Section III, Class 2 and 3 component supports.

3.9.3.4.3 Snubbers Used as Component and Piping Supports

The location and size of the snubbers are determined by stress analysis. Access for the testing, inspection, and maintenance of snubbers is considered in the AP1000 layout. The location and line of action of a snubber are selected based on the necessity of limiting seismic stresses in the piping and nozzle loads on equipment. Snubbers are chosen in lieu of rigid supports where restricting thermal growth would induce excessive thermal stresses in the piping or nozzle loads or equipment. Snubbers that are designed to lock up at a given velocity are specified with lock-up velocities sufficiently large to envelope the highest thermal growth rates of the pipe or equipment for design thermal transients. The snubbers are constructed to ASME Code, Section III, Subsection NF standards.

[*In the piping system seismic stress analysis, the snubbers are modeled as stiffness elements. The stiffness value is based on vendor stiffness data for the snubber, snubber extension, and pipe clamp assembly.*]* Supports for active valves are included in the overall design and qualification of the valve.

The elimination of the analysis of dynamic effects of pipe breaks due to leak-before-break considerations, as outlined in subsection 3.6.3, permits the use of fewer snubbers than in plants that were designed without considering leak before break. Also, the AP1000 uses gapped support devices to minimize the use of snubbers. The evaluation of those snubbers used as supports is outlined below.

Design specifications for snubbers include:

- Seismic requirements
- Normal environmental parameters

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- Accident/post-accident environmental parameters
- Full-scale performance test to measure pertinent performance requirements
- Instructions for periodic maintenance (in technical manuals)

Two types of tests will be performed on the snubbers to verify proper operation:

- Production tests, including dynamic testing, on every unit to verify proper operability

- Qualification tests on randomly selected production models to demonstrate the required load performance (load rating)

The production operability tests for large hydraulic snubbers (that is, those with capacities of 50 kips or greater) include 1) a full Level D load test to verify sufficient load capacity, 2) testing at full load to verify proper bleed with the control valve closed, 3) testing to verify the control valve closes within the specified velocity range, and 4) testing to demonstrate that breakaway and drag loads are within the design limits.

The operability of essential snubbers is verified by the Combined License applicant by verifying the proper installation of the snubbers, and performing visual inspections and measurements of the cold and hot positions of the snubbers as required during plant heatup to verify the snubbers are performing as intended. The ASME OM Code used to develop the inservice testing plan for the AP1000 Design Certification is the 1995 Edition and 1996 Addenda. Inservice testing is performed in accordance with Section XI of the ASME Code and applicable addenda, as required by 10 CFR 50.55a.

3.9.3.5 Instrumentation Line Supports

[*The design loads, load combinations, and acceptance criteria for safety-related instrumentation supports are similar to those of pipe supports. Design loads include deadweight, thermal, and seismic (as appropriate). The acceptance criteria is ASME Subsection NF.*]*

3.9.4 Control Rod Drive System (CRDS)

3.9.4.1 Descriptive Information of CRDS

3.9.4.1.1 Control Rod Drive Mechanism (CRDM)

The AP1000 control rod drive mechanism is based on a proven Westinghouse design that has been used in many operating nuclear power plants. Figure 3.9-4 shows the control rod drive mechanism. Figure 4.2-8 shows the configuration of the driveline, including the control rod drive mechanism. Subsection 4.2.2 describes the design of the rod cluster control assemblies and gray rod control assemblies. The material requirements for the control rod drive mechanisms and the control assemblies are discussed in Section 4.5.

Control rod drive mechanisms are located on the head of the reactor vessel. They are coupled to rod cluster control assemblies (RCCAs) that have neutron absorber material over the active length of the control rods. The control rod drive mechanisms are also attached to gray rod control assemblies (GRCAs) that are used for load follow. The gray rod control assemblies are

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

geometrically identical to the rod cluster control assemblies except that most of the rodlets are fabricated of stainless steel instead of containing absorber material.

The control rod drive mechanisms for both the rod cluster control assemblies and the gray rod control assemblies are identical. Although the gray rod control assemblies are expected to drop during a trip insertion, the insertion of these assemblies is not required in order to shut down the reactor.

The primary functions of the control rod drive mechanism is to insert or withdraw, at a designated speed, 53 rod cluster control assemblies and 16 gray rod control assemblies from the core to control average core temperature. During startup and shutdown the control assemblies control changes in reactivity.

Operation of the control rod drive mechanisms is integrated to move groups of assemblies together. Each cluster assembly is in a bank of assemblies which is used for reactivity control, axial power distribution control, or shutdown control. The assemblies of each bank of several rod cluster control assemblies or gray rod control assemblies move at the same time.

The design of the control rod drive mechanisms and the control assemblies permits load follow without the use of chemical shim over most of the life of the core. The design of the control rod drive mechanisms also permits holding the rod cluster control assemblies and the gray rod control assemblies at any step elevation within the range of rod travel during normal operation. The rod cluster control assemblies and gray rod control assemblies have the same mechanical coupling with the control rod drive mechanism.

The control rod drive mechanism is a magnetically operated jack (magjack). A magnetic jack is an arrangement of three electromagnets energized in a controlled sequence by a power cycle to insert or withdraw rod cluster control assemblies and gray rod control assemblies in the reactor core in discrete steps. The control rod drive mechanism is designed to release the drive rod and rod cluster control assembly during any part of the power cycle sequencing if electrical power to the coils is interrupted. When released from the control rod drive mechanism, the drive rod and rod cluster control assembly or gray rod control assembly falls by gravity into a fully inserted position.

The control rod drive mechanism consists of four separate subassemblies. These are the pressure vessel, coil stack assembly, latch assembly, and drive rod assembly.

The pressure vessel includes a latch housing and a rod travel housing that are connected by a threaded, seal-welded, maintenance joint that facilitates removal of the latch assembly. The closure at the top of the rod travel housing is a solid, one-piece construction providing seismic support by an interface with the integrated head package. The latch housing is the lower portion of the vessel and contains the latch assembly. The latch housing portion of the control rod drive mechanism is attached to the vessel head by a shrink-fit and a partial penetration weld. The rod travel housing is the upper portion of the vessel and provides space for the drive rod during its upward movement as the control rods are withdrawn from the core.

The coil stack assembly includes the coil housings, electrical conduit and connector, and three operating coils: the stationary gripper coil, the movable gripper coil, and the lift coil. The coil stack assembly is a separate unit. It is installed on the drive mechanism by sliding it over the

outside of the latch housing. It rests on the base of the latch housing without mechanical attachment. Energizing the operating coils causes movement of the pole pieces and latches in the latch assembly.

The latch assembly includes the guide tube, stationary pole pieces, movable pole pieces, and two sets of latches: the movable gripper latches and the stationary gripper latches. The latches engage grooves in the drive rod assembly. The movable gripper latches are moved up or down in 5/8-inch steps by the lift pole to raise or lower the drive rod. The stationary gripper latches hold the drive rod assembly while the movable gripper latches are repositioned for the next 5/8-inch step.

The drive rod assembly includes a coupling, drive rod, disconnect button, disconnect rod, and locking button. The drive rod has a 5/8-inch pitch from groove to groove that engage the latches during holding or moving of the drive rod. The coupling is attached to the drive rod and provides the means for coupling to the rod cluster control assembly directly below the control rod drive mechanism. The disconnect button, disconnect rod, and locking button provide positive locking of the coupling to the rod cluster control assembly and permit remote disconnection of the drive rod.

The control rod drive mechanism withdraws and inserts a rod cluster control assembly or gray rod control assembly as shaped electrical pulses are received by the operating coils. An on or off sequence, repeated by silicon-controlled rectifiers in the power programmer, causes either withdrawal or insertion of the control rod. Withdrawal of the drive rod and rod cluster control assembly or gray rod control assembly is accomplished by magnetic forces. Insertion is by gravity. The mechanism is capable of raising or lowering a maximum 400-pound load (which includes the drive rod weight) at a rate of 45 inches per minute.

During plant operation the stationary gripper coil of the drive mechanism holds the rod cluster control assembly in a static position until a stepping sequence is initiated, at which time the movable gripper coil and lift coil are energized sequentially.

The control rod position is measured by 48 discrete coils mounted on the position indicator assembly surrounding the rod travel housing. Each coil magnetically senses the entry and presence of the top of the ferromagnetic drive rod assembly as it moves through the coil center line.

The mechanism internals are designed to operate in 650°F reactor coolant. The pressure vessel is designed to contain reactor coolant at 650°F and 2500 psia. The three operating coils are designed to operate at 392°F, with forced-air cooling required to maintain the coil internal temperature at or below 392°F. The air for cooling is provided by fans and shrouds included as part of the integrated head package. A loss of the air cooling would be expected to result in the release of the drive rod in the worst case. For this reason, the cooling air is not required to be a safety-related system and does not require an emergency power supply.

The design and construction of the control rod drive mechanism includes provisions to establish that gross failure of the housing sufficient to allow a control rod to be ejected from the core is not credible. These provisions include the following:

- Construction of the housing of Type 304 stainless steel, which exhibits excellent notch toughness at the temperatures that will be encountered.

- Stress levels in the mechanism are not affected by system thermal transients at power or by thermal movement of the reactor coolant loops.

- The control rod drive mechanisms are hydrotested after manufacture at a minimum of 150 percent of system design pressure.

- The housings are hydrotested at a minimum of 125 percent of system design pressure after installation to the reactor vessel head individually and during the hydro test of the completed reactor coolant system.

The analyses of postulated accidents discussed in Chapter 15 include the evaluation of a nonmechanistic control rod ejection. Section 3.5 does not consider ejected rods to be a credible missile.

3.9.4.1.2 Control Rod Withdrawal

The rod cluster control assembly is withdrawn by repeating the following sequence of events. The sequence, starting with the stationary gripper energized in the hold position, is as follows:

1. Movable Gripper Coil B - ON

   The latch-locking plunger rises and swings the movable gripper latches into the drive rod assembly groove. A small axial clearance exists between the latch teeth and the drive rod.

2. Stationary Gripper Coil A - OFF

   The force of gravity, acting upon the drive rod assembly and attached control rod, causes the stationary gripper latches and plunger to move downward 1/16 inch, transferring the load of the drive rod assembly and attached control rod to the movable gripper latches. The plunger continues to move downward and swings the stationary gripper latches out of the drive rod assembly groove.

3. Lift Coil C - ON

   The 5/8-inch gap between the movable gripper pole and the lift pole closes, and the drive rod assembly rises one step length (5/8 inch).

4. Stationary Gripper Coil A - ON

   The plunger rises and closes the gap below the stationary gripper pole. The three links, pinned to the plunger, swing the stationary gripper latches into a drive rod assembly groove. The latches contact the drive rod assembly and lift it (and the attached control rod) a small fraction of an inch. The small vertical drive rod assembly movement transfers the drive rod assembly load from the movable gripper latches to the stationary gripper latches.

5. Movable Gripper Coil B - OFF

   The latch-locking plunger separates from the movable gripper pole under the force of a spring and gravity. Three links, pinned to the plunger, swing the three movable gripper latches out of the drive rod assembly groove.

6. Lift Coil C - OFF

   The gap between the movable gripper pole and the lift pole opens. The movable gripper latches drop 5/8 inch to a position adjacent to a drive rod assembly groove.

7. Repeat Step

   The sequence just described (items 1 through 6) is termed one step or one cycle. The rod cluster control assembly moves 5/8 inch for each step or cycle. The sequence is repeated at a rate of up to 72 steps per minute, and the drive rod assembly (which has a 5/8-inch groove pitch) is raised 72 grooves per minute. The rod cluster control assembly is thus withdrawn at a rate of up to 45 inches per minute. The gray rod control assemblies are withdrawn in an identical manner.

3.9.4.1.3 Control Rod Insertion

The sequence for rod cluster control assembly insertion is similar to that for control rod withdrawal, except that the timing of lift coil C ON and OFF is changed to permit lowering of the control assembly. The sequence, starting with the stationary gripper energized in the hold position, is as follows:

1. Lift Coil C - ON

   The 5/8-inch gap between the movable gripper and lift the pole closes. The movable gripper latches are raised to a position adjacent to a drive rod assembly groove.

2. Movable Gripper Coil B - ON

   The latch-locking plunger rises and swings the movable gripper latches into a drive rod assembly groove. A small axial clearance exists between the latch teeth and the drive rod assembly.

3. Stationary Gripper Coil A - OFF

   The force of gravity, acting upon the drive rod assembly and attached rod cluster control assembly, causes the stationary gripper latches and plunger to move downward 1/16 inch transferring the load of the drive rod assembly and attached rod cluster control assembly to the movable gripper latches. The plunger continues to move downward and swings the stationary gripper latches out of the drive rod assembly groove.

4. Lift Coil C - OFF

   The force of gravity and spring force separate the movable gripper pole from the lift pole. The drive rod assembly and attached rod cluster control assembly drop down 5/8 inch.

5. Stationary Gripper A - ON

   The plunger rises and closes the gap below the stationary gripper pole. The three links, pinned to the plunger, swing the three stationary gripper latches into a drive rod assembly groove. The latches contact the drive rod assembly and lift it (and the attached control rod) a small fraction of an inch. The small, vertical drive rod assembly movement transfers the drive rod assembly load from the movable gripper latches to the stationary gripper latches.

6. Movable Gripper Coil B - OFF

   The latch-locking plunger separates from the movable gripper pole under the force of a spring and gravity. Three links, pinned to the plunger, swing the three movable gripper latches out of the drive rod assembly groove.

7. Repeat Step

   The sequence is repeated, as for rod cluster control assembly withdrawal, up to 72 times per minute, which gives an insertion rate of 45 inches per minute. The gray rod control assemblies are inserted in an identical manner.

3.9.4.1.4 Holding and Tripping of the Control Rods

During most of the plant operating time, the control rod drive mechanisms hold the rod cluster control assemblies withdrawn from the core in a static position. During most plant operation the gray rod control assemblies are held by the control rod drive mechanisms withdrawn or inserted in the core in a static position as directed by flux shape considerations. In the holding mode, only one coil, stationary gripper coil A, is energized on each mechanism. The drive rod assembly and attached rod cluster control assemblies or gray rod control assemblies hang suspended from the three latches.

When the drive line is positioned in the last few steps, the rod cluster control assemblies and gray rod control assemblies are out of the last portion of the core, although not fully withdrawn from the fuel assemblies. This covers the range of steps from 263-266. The control rod drive mechanism may be located at any one or more of these step locations during operation of the plant and be considered fully out without any adverse impact on the control rod drive mechanism or plant operation.

The rod clusters cannot be physically withdrawn from the guide tubes by the control rod drive mechanisms since no additional grooves are machined in the drive rod past the last position.

If power to the stationary gripper coil is cut off, the combined weights of the drive rod assembly and the rod cluster control assembly or gray rod control assembly (plus the stationary gripper return spring) move the latches out of the drive rod assembly groove. The trip occurs as the

magnetic field, holding the stationary gripper plunger against the stationary gripper pole, collapses; and the stationary gripper plunger is forced down by the stationary gripper return spring and the weight acting upon the latches.

The control rod falls by gravity into the core. After the driveline is released by the mechanism, it falls freely until the control rods enter the dashpot section of the fuel assembly where the coolant in the guide tubes slows the rate of descent until the rods are fully inserted.

3.9.4.1.5 Testing Program

As noted earlier, the AP1000 control rod drive mechanism is based on a proven Westinghouse design that has been used in many operating nuclear power plants. The control rod cluster and fuel assembly thimble tube mechanical design is also based on a proven design. The production tests that each control rod drive mechanism undergoes are outlined in subsection 3.9.4.4.

3.9.4.2 Applicable CRDS Design Specifications

The specifications for the design, fabrication, construction, and operation of the control rod drive system (CRDS) include provisions related to the functional requirements, pressure boundary integrity, strength and durability of the internal components, and electrical requirements for the operating mechanism. The specifications and design requirements are consistent with the safety classification of the various parts of the control rod drive system as defined in Section 3.2.

The materials used in the control rod drive mechanisms are discussed in subsection 4.5.1. The rod position instrumentation is described in Section 7.7.

Since the AP1000 control rod drive mechanism is a design previously provided for other nuclear power plants the specifications are well established. The specifications are outlined in the following discussions.

3.9.4.2.1 Control Rod Drive Mechanism Functional Requirements

The suitability of the functional requirements for the step size and rate of withdrawal and insertion during normal operation and the time to drop into the core have been demonstrated during many years of successful operation of similar Westinghouse-designed control rod drive mechanisms. The time required for the control rod drive system to release the rod cluster control assemblies into the core is evaluated to determine that it is sufficient in analyses of postulated accident conditions. For a discussion of the evaluation of the performance of the reactivity control function of the AP1000 control rod drive system and specific AP1000 accident analyses see Section 4.6 and Chapter 15.

The basic operational requirements for the control rod drive mechanisms follow:

- 5/8-inch step
- 166.755 inch travel, maximum (cold conditions)
- 400-pound maximum load

- Step in or out at 45 inches per minute (72 steps per minute) maximum, 5 inches per minute (8 steps per minute) minimum

- Electrical power interruption initiating release of drive rod assembly

- Trip delay time of less than or equal to 150 millisecond. Free fall of drive rod assembly is to begin less than 150 millisecond after power interruption, no matter what holding or stepping action is being executed, with any load and coolant temperature of 100°F to 650°F.

- 60-year design objective with normal refurbishment

  Testing and operating experience has validated these requirements and the capability of the AP1000 control rod drive mechanism design to meet them.

3.9.4.2.2 Pressure Housing Requirements

The pressure housing portion of the control rod drive mechanism, the latch housing and rod travel housing, comprises a portion of the reactor coolant pressure boundary. The design pressure and temperature for the control rod drive mechanism pressure housing are the same as for the reactor vessel.

As part of the reactor coolant pressure boundary, the pressure housing is constructed in conformance with requirements in 10 CFR 50.55a. The conformance of the reactor coolant pressure boundary with applicable code and standards is discussed in Section 5.2. The pressure housing meets design, material, fabrication, analysis, quality assurance, and other requirements for Class 1 components in ASME Code, Section III. The pressure housing is required to meet stress requirements for design and transient conditions.

3.9.4.2.3 Internal Component Requirements

The internal components of the control rod drive mechanism include the latch assembly, drive rod and the coupling that attaches the drive rod to the rod cluster control assemblies and gray rod control assemblies.

The design, fabrication, inspection, and testing of these non-pressure boundary components typically do not come under the jurisdiction of the ASME Code. For those materials which do not have established stress limits the limits are based on the material specification mechanical property requirements.

In addition to dead-weight and operational loads, the design of the driveline is evaluated for loads due to safe shutdown earthquake and flow induced vibration.

Postulated failures of drive rod assemblies and latch mechanisms by fracture or decoupling lead to a decrease in reactivity. A postulated failure leading to the release of a drive rod or portion of a drive rod results in an insertion of control rods guided by the control rod assembly. A control rod drop is indicated by instrumentation that monitors the nuclear reaction and detect a decrease in reactivity.

A postulated failure of a control rod drive mechanism to insert a control assembly due to sticking or galling of the drive rod or latch assembly is accounted for in the safety analyses, which assume that the control assembly at the most reactive core location is inoperable.

In addition to the requirements related to the strength of the internal components, criteria have been developed for clearances in the latch assembly and between the latch arms and drive rod. The latch assembly has parts of austenitic and ferritic stainless steels and other alloys. Differential thermal expansion could eliminate clearances and result in binding or otherwise restrict movement of the latch assembly if not allowed for in the design.

The design requirement is that sufficient clearance exist between the moving parts in the latch assembly at expected operating and design condition temperatures. An evaluation of the thermal expansion, room temperature clearances, and geometry demonstrates that an appropriate clearance is available at design and normal operating conditions.

For the magjack mechanism to work properly to insert or withdraw the control rods, the latch arms contacting the drive rod, (that is the movable and stationary gripper latches) must not be under load at the same time. The effect of the differential thermal expansion on the latch arms, pressure housing, is evaluated to provide that the appropriate clearance between the drive rod and the unloaded latch arm is maintained.

3.9.4.2.4 Coil Stack Assembly Requirements

The coil stack assembly provides the electromotive force to move the latches in the latch assembly. The safety function of rapid insertion of the control rods can be accomplished by removing power from the coils. The separation and redundancy required of the control system and power supplied to the control rod drive system is discussed in Section 4.6.

Postulated electrical or structural failures of the coil assembly do not result in a condition would prevent control rod insertion. As a result, the electrical coils are built using standard industrial quality assurance and are not required to be built to IEEE Class 1E standards.

The coil stack assembly is located outside the pressure housing. The assembly does not come in contact with the reactor coolant and does not have any pressure-retaining function. The operating temperature of the coils is maintained below 392°F.

The coil stack assembly slides over the pressure housing and remains in place without a permanent mechanical or welded attachment. The assembly clearances permit removal of an assembly even when the control rod drive mechanism is at normal operating temperature. Thus, a malfunctioning coil assembly could be replaced without a complete cooldown of the plant. The clearances between the coil and coil housing are selected to minimize the gap at normal operating temperature to facilitate coil cooling.

3.9.4.3 Design Loads, Stress Limits, and Allowable Deformations

The pressure housing portion of the control rod drive mechanism is a Class 1 component required to meet the requirements of ASME Code, Section III. Subsection 3.9.3 defines the loading

combinations considered in the evaluation of ASME Code, Section III, pressure boundary components.

For each loading combination, the appropriate stresses due to pressure, component weight, external loads, hydraulic forces, thermal gradients, and seismic dynamic forces are evaluated and demonstrated to be less than the applicable stress limits. The cyclic stresses are combined with constant stresses to evaluate the fatigue usage due to cyclic loads. The transients used in the evaluation of cyclic loads are described in subsection 3.9.1. The effect of seismic events is addressed by considering a seismic event with an amplitude equal to one-third of the safe shutdown earthquake evaluated as a Level B event. The seismic contribution to the fatigue evaluation is based on five seismic events with an amplitude of one-third the safe shutdown earthquake and with 63 cycles per event. The results of the stress evaluation are documented in a component stress report, as required by the ASME Code.

The control rod drive mechanism is supported by the attachment of the bottom of the assembly to the reactor vessel head and a connection to the integrated head package at the top of the rod travel housing. The integrated head package also provides the support to the cooling air shrouds and control rod drive mechanism electrical supply cables to prevent excessive loading on the control rod drive mechanisms during seismic events.

Hydrostatic tests according to the requirements of the ASME Code verify the pressure boundary integrity of the pressure housing prior to operation. The latch assembly housing is assembled to the reactor vessel head by the vessel supplier and is hydro tested as part of the vessel hydro test. The rod travel housing seal weld is performed prior to final assembly following the assembly of the travel housing to the latch assembly housing. The hydrostatic test of the connection of the rod travel housing to the latch assembly is done as part of the system hydrostatic test.

To assure functional capability of the control rod dive mechanism following a seismic event or a pipe break, the bending moments on the control rod drive mechanisms are limited to those that produce stress levels in the pressure boundary of the control rod drive mechanism less than ASME Code limits during anticipated transient conditions. This limit provides that the rod travel housing does not bend to the extent that the drive rod binds during insertion of the control rods. The analysis evaluates the load combinations that include safe shutdown earthquake and pipe break. The pipe break considered is at least as large as the largest pipe in or connected to the reactor coolant system that is not qualified as leak before break line. See subsection 3.9.7 for information on the control rod drive mechanism deflection limit requirements for the integrated head package.

3.9.4.4 Control Rod Drive Mechanism Performance Assurance Program

The capability of the pressure housing components to perform throughout the 60 year design objective is confirmed by the stress analysis report required by the ASME Code, Section III.

To confirm the operational adequacy of the combination of fuel assembly, control rod drive mechanism, and rod cluster control assembly, functional test programs have been conducted. These tests verify that the trip time achieved by the control rod drive mechanisms meets the design requirements. These tests have been reported in WCAP-8446 (Reference 9).

The units are production tested prior to shipment to confirm the capability of the control rod drive mechanism to meet design specification operation requirements. Each production control rod drive mechanism undergoes a production test as listed in Table 3.9-13.

The trip time requirement is confirmed for each control rod drive mechanism prior to initial reactor operation and at periodic intervals after initial reactor operation, as required by the technical specifications. See Section 14.2 for preoperational and startup testing.

To demonstrate proper operation of the control rod drive mechanism and to provide acceptable core power distributions, rod cluster control assembly partial movement checks are performed as required by the Technical Specifications. In addition, periodic drop tests of the rod cluster control assembly are performed at each refueling shutdown to demonstrate continued capability to meet trip time requirements, consistent with safety analyses in Chapter 15.

3.9.5 Reactor Pressure Vessel Internals

3.9.5.1 Design Arrangements

The AP1000 reactor internals consist of two major assemblies - the lower internals and the upper internals. The reactor internals provide the protection, alignment and support for the core, control rods, and gray rods to provide safe and reliable reactor operation. In addition, the reactor internals help to accomplish the following: direct the main coolant flow to and from the fuel assemblies; absorb control rod dynamic loads, fuel assembly loads, and other loads and transmit these loads to the reactor vessel; support instrumentation within the reactor vessel; provide protection for the reactor vessel against excessive radiation exposure from the core; and position and support reactor vessel radiation surveillance specimens.

During reactor operation, the core barrel directs the coolant flow from the reactor vessel inlet nozzles, through the downcomer annulus, and into the lower plenum below the lower core support plate. The flow then turns and passes through the lower support plate and into the core region. After leaving the core, it passes through the upper core plate; then bypasses through and around the control rod guide tubes and the support columns to reach the outlet nozzles. During operation, a small amount of inlet coolant is diverted from the core to cool the core shroud and the vessel head area.

3.9.5.1.1 Lower Core Support Assembly

The major containment and support member of the reactor internals is the lower core support assembly, shown in Figure 3.9-5. This assembly consists of the core barrel, lower core support plate, secondary core support, vortex suppression plate, core shroud, radial supports, and related attachment hardware. The major material for this structure is 300 series austenitic stainless steel. The lower core support assembly is supported at its upper flange from a ledge in the reactor vessel flange. Its lower end is restrained in its transverse movement by a radial support system attached to the vessel wall. The radial support system consists of keys attached to the lower end of the core barrel subassembly. These keys engage clevis inserts in the reactor vessel. This system restricts the lower end of the core barrel from rotational and/or translational movement, but allows for radial thermal growth and axial displacement.

The core shroud is located inside the core barrel and above the lower core support. This shroud forms the radial periphery of the core. Through the dimensional control of the cavity (the gap between the fuel assemblies and the shroud) and the shroud cooling flow inlets, the core shroud provides directional and metered control of the reactor coolant through the core. The core shroud serves to provide a transition from the round core barrel to the square fuel assemblies.

Loads acting vertically downward from weight, fuel assembly preload, control rod dynamic loading, hydraulic loads, and earthquake acceleration are carried by the lower core support plate into the core supports. The loads are then carried through the core barrel shell to the core barrel flange, which is supported by the vessel flange. Transverse loads from earthquake acceleration, coolant cross-flow, and vibration are carried by the core barrel shell and distributed through the lower radial support to the vessel wall and to the vessel flange. Transverse loads from the fuel assemblies are transmitted to the core barrel shell by direct connection of the lower core support plate to the barrel wall, and by upper core plate alignment pins.

The main radial support system of the lower end of the core barrel is accomplished by key and keyway joints to the reactor vessel wall. Clevis blocks are welded to the vessel inner diameter at equally spaced points around the inner circumference of the vessel. Another insert block is bolted to each of these blocks and has a keyway geometry. Opposite each of these is a key attached to the internals. During assembly, as the internals are lowered into the vessel, the keys engage the keyways in the axial direction. Correct positioning of the internals is provided by the installation equipment (lifting rig) guide studs and bushings. In this design, the internals have a support at the furthest extremity, and the core barrel is modeled as a beam, which is supported at the top and bottom.

Radial and axial expansion of the core barrel is accommodated, but transverse movement of the core barrel is restricted by this design. With this system, cyclic stresses in the internal structures are within ASME Code, Section III, Subsection NG limits.

In the event of an abnormal downward vertical displacement of the internals following a hypothetical failure, energy-absorbing devices limit the dynamic force imposed on the reactor vessel. The energy absorbing device is the secondary core support. In addition, the secondary core support also transmits the vertical load of the core uniformly to the reactor vessel, limits the displacement to prevent withdrawal of the control rods from the core, and limits the displacement to prevent loss of alignment of the core with the upper core support to allow the control rods to be inserted into the reactor.

The lower plenum vortex suppressor plate is positioned in the vessel lower plenum to suppress flow vortices formed by the reactor coolant flow reversal in this region. The suppressor plate is supported by columns from the lower core support plate.

3.9.5.1.2 Upper Core Support Assembly

The AP1000 upper core support assembly consists of the upper support, the upper core plate, the support columns, and the guide tube assemblies. Figure 3.9-6 shows the upper core support assembly.

The support columns establish the spacing between the upper support and the upper core plate. The support columns are fastened at the top and bottom to these plates. The support columns transmit the mechanical loadings between the two plates and some serve the supplementary function of supporting the tubes that house the fixed in-core detectors.

The instrument columns housing the in-core detector provide a protective path for the detectors during installation, reactor operation, and removal at refueling outages.

The guide tube assemblies sheath and guide the control rod drive shafts and control rods. The guide tubes are fastened to the upper support and are restrained by pins in the upper core plate for proper orientation and support.

The upper core support assembly is positioned in its proper orientation, with respect to the lower core support assembly, by flat-sided pins in the core barrel. Four equally spaced flat-sided pins are located at an elevation in the core barrel where the upper core plate is positioned. Four mating sets of inserts are located in the upper core plate at the same positions. As the upper support assembly is lowered into the lower support assembly, the inserts engage the flat-sided pins in the axial direction. Lateral displacement of the plate and of the upper support assembly is restricted by this design.

Fuel assembly locating pins protrude from the bottom of the upper core plate and engage the fuel assemblies as the upper assembly is lowered into place. This system of locating pins and guidance arrangement provides proper alignment of the lower core support assembly, the upper core support assembly, the fuel assemblies, and control rods.

The upper and lower core support assemblies are preloaded by a large circumferential spring, which rests between the upper barrel flange and the upper core support assembly. This spring is compressed by installation of the reactor vessel head.

Vertical loads from weight, earthquake acceleration, hydraulic loads, and fuel assembly preload are transmitted through the upper core plate via the support columns, to the upper support, and then into the reactor vessel head. Transverse loads from coolant cross-flow, earthquake acceleration, and possible vibrations are distributed by the support columns to the upper support and upper core plate. The upper support plate is particularly stiff to minimize deflection.

3.9.5.1.3 Core Shroud

The core shroud is between the lower core barrel and core, surrounding the core and forming the core cavity. The core shroud consists of formed vertical plates with fully welded vertical seams to prevent lateral flow from the fuel assemblies. This core shroud is a proven design that is currently utilized in operating plants.

3.9.5.1.4 Reactor Internals Interface Arrangement

Figure 3.9-8 shows the arrangement of reactor internals components shown in Figures 3.9-5 and 3.9-6 and their relative position in the reactor vessel. As shown in the figure, the lower reactor internal (Figure 3.9-5) rests on the vessel ledge. The upper core support structure (Figure 3.9-6) also rests at the same location on the top of a large compression spring (hold down spring). The

hold down spring is between the upper support plate flange and the core barrel flange as shown in the figure. Both the assemblies are held together by reactor vessel closure studs, which clamp the upper head to upper shell of reactor vessel. The lower reactor internals are also guided laterally by four support lugs welded to the bottom head of reactor vessel.

3.9.5.2 Design Loading Conditions

3.9.5.2.1 Level A and B Service Conditions

The level A and B service conditions that provide the basis for the design of the reactor internals are:

- Fuel assembly and reactor internals weight
- Fuel assembly and core component spring forces, including spring preloading forces
- Differential pressure and coolant flow forces
- Temperature gradients
- Operational thermal transients listed in Table 3.9-1
- Differences in thermal expansion, due to temperature differences and differential expansion of materials
- Loss of load/pump overspeed
- Earthquake (included only in fatigue evaluation; amplitude equal to one-third of the safe shutdown earthquake response)

3.9.5.2.2 Level C Service Conditions

The Level C service conditions that are the basis for the design of the reactor internals are small break loss of coolant accident, and small steam line break.

3.9.5.2.3 Level D Service Conditions

The Level D service conditions that are the basis for the design of the reactor internals are safe shutdown earthquake (SSE), and pipe rupture. The pipe ruptures are evaluated for lines for which dynamic effect can not be excluded based on mechanistic pipe break criteria. See subsection 3.6.3 for a description of mechanistic pipe break criteria. The breaks considered are those inside containment, in systems that carry reactor coolant, steam and feedwater. These breaks have the greatest effect on the reactor internals response.

3.9.5.2.4 Design Loading Categories

The combination of design loadings fit into either the service level A, B, C, or D conditions shown on Figures NG-3221-1 and NG-3224-1, NG-3232-1, and by Appendix F of the ASME Code, Section III.

3.9.5.3 Design Bases

The reactor vessel internals components designated as ASME III Class CS core support structures are designed, fabricated, and examined in accordance with the requirements of ASME III, Subsection NG for Core Support Structures. The design documentation for these Class CS core support structures include a certified Design Specification and a certified Design Report conforming to the requirements of ASME III, Subsection NCA.

The basis used for design, construction, and examination, for those reactor vessel internals components not designated ASME III Class CS core support structures, is defined by Westinghouse as provided in the ASME Code, Subsection NG.

The scope of the stress analysis requires many different techniques and methods, both static and dynamic. The analysis performed depends on the mode of operation.

3.9.5.3.1 Mechanical Design Basis

The design bases for the mechanical design of the AP1000 reactor vessel internals components are as follows:

- The reactor internals, in conjunction with the fuel assemblies, direct reactor coolant through the core to achieve an acceptable flow distribution and to restrict bypass flow so that the heat transfer performance requirements are met for the varying modes of operation. In addition, required cooling for the reactor pressure vessel head is provided so that the temperature differences between the vessel flange and head do not result in leakage from the flange during reactor operation.

- The core shroud forms the core cavity and directs the reactor coolant flow through the fuel assemblies.

- Provisions are made for installing in-core instrumentation useful for plant operation, and vessel material test specimens required for a pressure vessel irradiation surveillance program.

- The core internals are designed to withstand mechanical loads arising from the safe shutdown earthquake and to meet the requirements of the following item.

  The reactor has mechanical provisions which are sufficient to adequately support the core and internals and to maintain the core intact with acceptable heat transfer geometry following transients arising from abnormal operating conditions.

- Following a design basis accident, the plant is capable of being shut down and cooled in an orderly fashion, so that the fuel cladding temperature is kept within specified limits.

Therefore, the deformation of certain critical reactor internals is kept sufficiently small to allow continued core cooling.

The functional limitations for the core structures and internal structures during the design basis accident are shown in Table 3.9-14.

Details of the dynamic analyses, input forcing functions, and response loadings are presented in subsection 3.9.2.

3.9.5.3.2 Allowable Deflections

Loads and deflections imposed on components, as a result of shock and vibration, are determined analytically and/or experimentally in both scaled models and operating reactors. The cyclic stresses resulting from these dynamic loads and deflections are combined with the stresses imposed by loads from component weights, hydraulic forces, and thermal gradients for the determination of the total stresses of the internals.

The reactor internals are designed to withstand stresses originating from various operating conditions, as summarized in Table 3.9-1.

For normal operating conditions, downward vertical deflection of the lower core support plate is negligible.

For normal operating and accident conditions, the deflection criteria of internal structures are the limiting values given in Table 3.9-14. The upper barrel radial inward deflection limit is based on preventing contact between the barrel and the peripheral upper guide tubes during a LOCA event. The rod cluster control assembly can be dropped during the LOCA event if the guide tubes are not contacted by the barrel. The radial outward (uniform) deflection is based on maintaining flow in the downcomer annulus between the core barrel and pressure vessel wall. A peak deflection greater than the uniform allowable is acceptable provided that the annulus blockage from the deflected core barrel is less than the non-uniform radial outward deflection limit. The upper package allowable deflection is based on the clearance between the upper core plate and guide tube support pin shoulder. Exceeding this value could result in potential buckling of the guide tube and potential loss of function during operating or accident conditions. The rod cluster guide tube allowable lateral deflection is based on test data that indicates the rod cluster control assembly drop time will not be impaired.

The criteria for the postulated core drop accident are based on analyses that determine the total downward displacement of the internal structures, following a hypothetical core drop resulting from loss of the normal core barrel supports. The initial clearance between the secondary core support structures and the reactor vessel lower head in the hot condition is approximately 0.5 inch. An additional displacement of approximately 0.6 inch would occur from the strain of the energy-absorbing devices of the secondary core support. Therefore, the total drop distance is about 1.1 inches. That distance is less than the distance that permits the tips of the rod cluster control assembly to come out of the guide thimble in the fuel assemblies.

The secondary core support is only required to function during an accident involving the hypothetical catastrophic failure of core support (such as core barrel or barrel flange). There are

four supports in each reactor. This structure limits the fall of the core and absorbs much of the energy of the fall which otherwise would be imparted to the vessel.

The energy of the fall is calculated assuming a complete and instantaneous failure of the primary core support. The energy is absorbed during the plastic deformation of the controlled volume of stainless steel loaded in tension. The maximum deformation of this austenitic stainless piece is limited to approximately 18 percent, after which a positive stop is provided. The maximum deformation of the secondary core support allows for the maintenance of flow paths through the lower portion of the vessel and lower core support to provide cooling of the fuel under forced and natural circulation conditions.

3.9.6 Inservice Testing of Pumps and Valves

Inservice testing of ASME Code, Section III, Class 1, 2, and 3 pumps and valves is performed in accordance with Section XI of the ASME Code and applicable addenda, as required by 10 CFR 50.55a(f), except where specific relief has been granted by the NRC in accordance with 10 CFR 50.55a(f). The Code includes requirements for leak tests and functional tests for active components.

The requirements for system pressure tests are defined in the ASME Code, Section XI, IWA-5000. These tests verify the pressure boundary integrity and are part of the inservice inspection program, not part of the inservice test program.

Testing requirements for components constructed to the ASME Code are in several parts of the ASME OM Code (Reference 2). The ASME OM Code used to develop the inservice testing plan for the AP1000 Design Certification is the 1995 Edition and 1996 Addenda. The edition and addenda to be used for the inservice testing program are administratively controlled by the Combined License applicant. A limited number of valves not constructed to the ASME Code are also included in the inservice testing plan using the requirements of the ASME OM Code. These valves are relied on in some safety analyses.

The specific ASME Code requirements for functional testing of pumps are found in the ASME OM Code, Subsection ISTB. The specific ASME Code requirements for functional testing of valves are found in the ASME OM Code, Subsection ISTC. The functional tests are required for pumps and valves that have an active safety-related function.

The AP1000 inservice test plan does not include testing of pumps and valves in nonsafety-related systems unless they perform safety-related missions, such as containment isolation. Subsection 16.3.1 describes the evaluation of the importance of nonsafety-related systems, structures and components. Fluid systems with important missions are shown to be available by operation of the system.

The AP1000 inservice test plan includes periodic systems level tests and inspections that demonstrate the capability of safety-related features to perform their safety-related functions such as passing flow or transferring heat. The test and inspection frequency is once every 10 years. Staggering of the tests of redundant components is not required. These tests may be performed in conjunction with inservice tests conducted to exercise check valves or to perform power-operated valve operability tests. Alternate means of performing these tests and inspections that provide

equivalent demonstration may be developed by the Combined License applicant in the inservice test program. Table 3.9-17 identifies the system inservice tests.

A preservice test program, which identifies the required functional testing, is to be submitted to the NRC by the Combined License applicant prior to performing the tests and following the start of construction. The inservice test program, which identifies requirements for functional testing, is to be submitted to the NRC prior to the anticipated date of commercial operation by Combined License applicant. Table 3.9-16 identifies the components subject to the preservice and the inservice test program. This table also identifies the method, extent, and frequency of preservice and inservice testing.

3.9.6.1 Inservice Testing of Pumps

Safety-related pumps are subject to operational readiness testing. The only safety-related mission performed by an AP1000 pump is the coast down of the reactor coolant pumps. As a result, the AP1000 inservice test plan does not include any pumps.

The AP1000 inservice test plan does not include testing of pumps in nonsafety-related systems unless they perform safety-related missions. Systems containing pumps with important missions have the capability during operation to measure the flow rate, the pump head, and pump vibration to confirm availability of the pumps. These measurements may be made with temporary instruments or test devices. The AP1000 inservice test plan does not include testing of nonsafety-related pumps because they do not perform safety-related missions.

3.9.6.2 Inservice Testing of Valves

Safety-related valves and other selected valves are subject to operational readiness testing. Inservice testing of valves assesses operational readiness including actuating and position indicating systems. The valves that are subject to inservice testing include those valves that perform a specific function in shutting down the reactor to a safe shutdown condition, in maintaining a safe shutdown condition, or in mitigating the consequences of an accident. The AP1000 safe shutdown condition includes conditions other than the cold shutdown mode. Safe shutdown conditions are discussed in subsection 7.4.1. In addition, pressure relief devices used for protecting systems or portions of systems that perform a function in shutting down the reactor to a safe shutdown condition, in maintaining a safe shutdown condition, or in mitigating the consequences of an accident, are subject to inservice testing.

The AP1000 inservice test plan does not include testing of nonsafety-related valves except where they perform safety-related missions. Valves that are identified as having important nonsafety-related missions have provisions to allow testing but are not included in the inservice test plan unless inservice testing is identified as part of the regulatory oversight required for investment protection (see Section 16.3). This testing may use temporary instruments or test devices.

The valve test program is controlled administratively by the Combined License holder and is based on the plan outlined in this subsection. Valves (including relief valves) subject to inservice testing in accordance with the ASME Code are indicated in Table 3.9-16. This table includes the type of testing to be performed and the frequency at which the testing should be performed. The test program conforms to the requirements of ASME OM, Subsection ISTC, to the extent

practical. The guidance in NRC Generic Letters, AEOD reports, and industry and utility guidelines (including NRC Generic Letter 89-04) is also considered in developing the test program. Inservice testing incorporates the use of nonintrusive techniques to periodically assess degradation and performance of selected valves.

Safety-related check valves with an active function are exercised in response to flow. Safety-related power-operated valves with an active function are subject to an exercise test and an operability test. The operability test may be either a static or a dynamic (flow and differential pressure) test. Refer to subsection 3.9.6.2.1 for additional information.

Relief from the requirements for testing, if required, and the alternative to the tests are justified and documented in DCD Table 3.9-16.

3.9.6.2.1 Valve Functions Tested

The AP1000 inservice testing program plan identifies the safety-related missions for safety-related valves for the AP1000 systems. The following safety-related valve missions have been identified in Table 3.9-16.

- Maintain closed
- Maintain open
- Transfer closed (active function)
- Transfer open (active function)
- Throttle flow (active function)

Based on the safety-related missions identified for each valve, the inservice tests to confirm the capability of the valve to perform these missions are identified. Active valves include valves that transfer open, transfer closed, and/or have throttling missions. Active valves, as defined in the ASME Code, include valves that change obturator (the part of the valve that blocks the flow stream) position to accomplish the safety-related function(s). Valve missions to maintain closed and maintain open are designated as passive and do not include valve exercise inservice testing.

If upon removal of the actuation power (electrical power, air or fluid for actuation) an active valve fails to the position associated with performing its safety-related function, it is identified as "active-to-fail" in Table 3.9-16.

Valve functions are used in determining the type of inservice testing for the valve. These valve functions include:

- Active or active-to-fail for fulfillment of the safety-related mission(s)

- Reactor coolant system pressure boundary isolation function

- Containment isolation function

- Seat leakage (in the closed position), is limited to a specific maximum amount when important for fulfillment of the safety-related mission(s)

- Actuators that fail to a specific position (open/closed) upon loss of actuating power for fulfillment of the safety-related mission(s)

- Safety-related remote position indication

The ASME inservice testing categories are assigned based on the safety-related valve functions and the valve characteristics. The following criteria are used in assigning the ASME inservice testing categories to the AP1000 valves.

Category A – safety-related valves with safety-related seat leakage requirements

Category B – safety-related valves requiring inservice testing, but without safety-related seat leakage requirements

Category C – safety-related, self-actuated valves (such as check valves and pressure relief valves)

Category D – safety-related, explosively actuated valves and nonreclosing pressure relief devices

3.9.6.2.2 Valve Testing

Four basic groups of inservice tests have been identified for the AP1000. These testing groups are described below.

Remote Valve Position Indication Inservice Tests

Valves that are included in the inservice testing program that have position indication will be observed locally during valve exercising to verify proper operation of the position indication. The frequency for this position indication test is once every two years. Where local observation is not practicable, other methods will be used for verification of valve position indicator operation. The alternate method and justification are provided in Table 3.9-16.

Valve Leakage Inservice Tests

Valves with safety-related seat leakage limits will be tested to verify their seat leakage. These valves include:

- Containment Isolation - valves that provide isolation of piping/lines that penetrate the containment.

Containment isolation valves are tested in accordance with 10 CFR 50, Appendix J. Depending on the function and configuration, some valves are tested during the integrated leak rate testing (Type A) or individually as a part of the Type C testing or both. The leak rate test frequency for containment isolation valves is defined in subsection 6.2.5. The provisions in 10 CFR 50.55a (b) 2. that require leakage limits and corrective actions for individual containment isolation valves by reference to ASME/ANSI OM, Part 10 apply to the AP1000 containment isolation valves. The Combined License applicant will address changes to these provisions.

The ASME Code specifies a test frequency of at least once every 2 years. The ASME Code does not require additional leak testing for valves that demonstrate operability during the course of plant operation. In such cases, the acceptability of the valve performance is recorded during plant operation to satisfy inservice testing requirements. Therefore, a specific inservice test need not be performed on valves that meet this criteria.

The AP1000 maximum leakage requirement for pressure isolation valves that provide isolation between high and low pressure systems is included in the surveillance requirements for Technical Specification 3.4.16. The pressure isolation valves that require leakage testing are tabulated in Table 3.9-18.

The AP1000 has no temperature isolation valves whose leakage may cause unacceptable thermal loading to piping or supports.

Manual/Power-Operated Valve Tests

Manual/Power-Operated Valve Exercise Tests - Safety-related active valves and other selected active valves, both manual- and power-operated (motor-operated, air-operated, hydraulically operated, solenoid-operated) will be exercised periodically. The ASME code specifies a quarterly valve exercise frequency. The AP1000 test frequencies are identified in Table 3.9-16.

In some cases, the valves are tested on a less frequent basis because it is not practicable to exercise the valve during plant operation. If an exception is taken to performing quarterly full-stroke exercise testing of a valve, then full-stroke testing will be performed during cold shutdowns on a frequency not more often than quarterly. If this is not practicable, then the full-stroke testing will be performed each refueling cycle.

The inservice testing requirement for measuring stroke time for valves in the AP1000 will be completed in conjunction with a valve exercise inservice test. The stroke time test is not identified as a separate inservice test.

Valves that operate during the course of normal plant operation at a frequency that satisfies the exercising requirement need not be additionally exercised, provided that the observations required of inservice testing are made and recorded at intervals no greater than that specified in this section.

Safety-related valves that fail to the safety-related actuation position to perform the safety-related missions, are subject to a valve exercise inservice test. The test verifies that the valve repositions to the safety-related position on loss of actuator power. The valve exercise test satisfies this test as long as the test removes actuator power for the valve. The fail-safe test is not identified as a separate test.

Power-Operated Valve Operability Tests - The inservice operability testing of power-operated valves rely on non-intrusive diagnostic techniques to permit periodic assessment of valve operability at design basis conditions. Table 3.9-16 identifies valves that may require valve operability testing. The specified frequency for operability testing is a maximum of once every 10 years. The initial test frequency is the longer of every 3 refueling cycles or 5 years until sufficient data exists to determine a longer test frequency is appropriate in accordance with

Generic Letter 96-05. The Combined License applicant is responsible for developing the inservice test program. Evaluation of the factors below by the Combined License applicant will determine which of the valves identified for operability testing in Table 3.9-16 will require operability testing and whether the operability testing will be static with diagnostic measurements or dynamic (flow and differential pressure).

- AP1000 PRA importance measures
- Design reliability assurance program contained in DCD Section 16.2
- Historical performance of power-operated valves (identify valve types which experience operating problems related to flow and differential pressure during opening and closing)
- Basic design of power-operated valves (identify valve types where flow affects the capability of power-operated valves to achieve their safety-related valve operation)
- Power-operated valves that operate under low differential pressures to perform their safety-related missions and incorporate adequate margin. Low differential pressure valves are identified in Table 3.9-16 with a note that indicates that the Combined License applicant will provide an evaluation based on test data to show that these valves have adequate margin and operability testing is not needed.
- Analysis of trends of valve test parameters during diagnostic static valve operability tests

Check Valve Tests

Check Valve Flow Tests - Safety-related check valves identified with specific safety-related missions to transfer open or transfer closed are tested periodically. Exercising a check valve confirms the valve capability to move to the position(s) to fulfill the safety-related mission(s). The exercise test shows that the check valve opens in response to flow and closes when the flow is stopped. Sufficient flow is provided to fully open the check valve unless the maximum accident flows are not sufficient to fully open the check valve. Either permanently or temporarily installed nonintrusive check valve indication is used for this test.

Valves that normally operate at a frequency that satisfies the exercising requirement need not be additionally exercised, provided that the observations required of inservice testing are made and recorded at intervals no greater than that specified in this section.

The ASME Code specifies a quarterly valve exercise frequency. The AP1000 test frequencies are identified in Table 3.9-16. In some cases, check valves are tested on a less frequent basis because it is not practical to exercise the valve during plant operation. If an exception is taken to performing quarterly exercise testing, then exercise testing is performed during cold shutdown on a frequency not more often than quarterly. If this is not practical, the exercise testing is performed during each refueling outage. If exercise testing during a refueling outage is not practical, then an alternative means is provided. Alternative means include nonintrusive diagnostic techniques or valve disassembly and inspection. Nonintrusive methods may include monitoring an upstream

pressure indicator, monitoring tank level, performing a leak test, a system hydrostatic, or pressure test, or radiography.

Check Valve Low Differential Pressure Tests - Safety-related check valves that perform a safety-related mission to transfer open under low differential pressure conditions have periodic inservice testing to verify the capability of the valve to initiate flow.

The intent of this inservice test is to determine the pressure required to initiate flow. This differential pressure will verify that the valve will initiate flow at low differential pressure. This low pressure differential inservice test is performed in addition to exercise inservice tests.

The specified frequency for this inservice test is once each refueling cycle.

Other Valve Inservice Tests

Explosively Actuated Valves - Explosively actuated valves are subject to periodic test firing of the explosive actuator charges. The inservice tests for these valves is specified in the ASME code. At least 20 percent of the charges installed in the plant in explosively actuated valves are fired and replaced at least once every 2 years. If a charge fails to fire, all charges with the same batch number are removed, discarded, and replaced with charges from a different batch. The firing of the explosive charge may be performed inside of the valve or outside of the valve in a test fixture. The maintenance and review of the service life for charges in explosively actuated valves follow the requirements in the ASME OM Code.

Pressure/Vacuum Relief Devices - Pressure relief devices that provide safety-related functions or that protect equipment in systems that perform AP1000 safety-related missions are specified by ASME to have periodic inservice testing. The inservice tests for these valves are identified in ASME IST, Appendix I.

The periodic inservice testing include visual inspection, seat tightness determination, set pressure determination, and operational determination of balancing devices, alarms, and position indication as appropriate. The frequencies for this inservice test is every 5 years for ASME Class 1 and main steam line safety valve or every 10 years for ASME Classes 2 and 3 devices. Nonreclosing pressure relief devices are inspected when installed and replaced every 5 years unless historical data indicate a requirement for more frequent replacement.

3.9.6.2.3 Valve Disassembly and Inspection

The Combined License applicant is responsible for developing a program for periodic valve disassembly and inspection. Evaluation of the factors below by the Combined License applicant will determine which of the valves identified in the inservice testing program in Table 3.9-16 will require disassembly and inspection and the frequency of the inspection.

- AP1000 PRA importance measures.
- Design reliability assurance program contained in DCD Section 16.2.

- Historical performance of power-operated valves (identify valve types which experience unacceptable degradation in service.)

- Basic design of valves including the use of components subject to aging and requiring periodic replacement.

- Analysis of trends of valve test parameters during valve inservice tests.

- Results of nonintrusive techniques. Disassembly and inspection may not be needed if nonintrusive techniques are sufficient to detect unacceptable valve degradation.

3.9.6.3 Relief Requests

Considerable experience has been used in designing and locating systems and valves to permit preservice and inservice testing required by Section XI of the ASME Code. Deferral of testing to cold shutdown or refueling outages in conformance with the rules of the ASME OM Code when testing during power operation is not practical is not considered a relief request. Relief from the testing requirements of the ASME OM Code will be requested when full compliance with requirements of the ASME OM Code of the Code is not practical. In such cases, specific information will be provided which identifies the applicable code requirements, justification for the relief request, and the testing method to be used as an alternative.

3.9.7 Integrated Head Package

The integrated head package (IHP) combines several components in one assembly to simplify refueling the reactor. Figure 3.9-7 illustrates the integrated head package. The integrated head package includes a lifting rig, seismic restraints for control rod drive mechanisms, support for reactor head vent piping, power cables, cables and conduit for in-core instrumentation, cable supports (including messenger tray and cable bridge), shroud, and cooling system.

The integrated head package provides the ability to rapidly disconnect the power and instrument cables from the components, including the control rod drive mechanism and the reactor head vent system. It also provides the ability to move these components as an assembly to permit the lifting and removal of the reactor vessel head. In addition, the integrated head package provides support for the vessel head multi-stud tensioner/detensioner during refueling.

The lifting rig function is discussed in subsection 9.1.5. The control rod drive mechanisms are discussed in subsection 3.9.4. The control rod drive mechanism support and cooling function is discussed in Section 4.6. The reactor vessel head vent function is discussed in subsection 5.4.12. The function and requirements of the in-core instrumentation are discussed in Chapter 7.

3.9.7.1 Design Bases

Components, including the shroud and control rod drive mechanism seismic support plate, required to provide seismic restraint for the control rod drive mechanisms and the valves and piping of the reactor head vent are AP1000 equipment Class C, seismic Category I. The shroud and seismic support plate are designed in accordance with the ASME Code, Section III, Subsection NF requirements.

The loads and loading combinations due to seismic loads for these components are developed using the appropriate seismic spectra.

The structural design of the integrated head package is based on a design temperature consistent with the heat loads from the vessel head, the control rod drive mechanisms, and electrical power cables. The design also considers changes in temperature resulting from plant design transients and loss of power to the cooling fans.

Components required to provide cooling to the control rod drive mechanisms are nonnuclear safety-related AP1000 equipment Class E. Section 4.6 offers a discussion of the effect of failure of cooling of the control rod drive mechanisms.

Those components that function as part of the lifting rig are required to be capable of lifting and carrying the total assembled load of the package. This includes the vessel head, control rod drive mechanisms, control rod drive mechanism seismic supports, cooling shroud, instrumentation support, cooling ducts and fans, stud tensioners, vessel studs, nuts, washers, instrumentation support structure, and insulation. The lifting rig components are required to meet the guidance for special lifting rigs, in NUREG-0612, (Reference 10). The lifting rig components are nonsafety-related, AP1000 equipment Class E.

The components of the in-core instruments support system (IISS) are required to remove and support the in-core instrumentation thimbles during refueling and maintenance. The routing of the tubing for the in-core instrumentation system is required to permit the installation of the instrumentation without binding and to prevent radiation shine through the tubing. The in-core instrumentation support system is AP1000 equipment Class E and is non-seismic.

The shroud assembly is required to provide radiation shielding of the control rod drive mechanism and the conduit for in-core instrumentation when the instrumentation is withdrawn into the conduit. The radiation level at the exterior surface of the cooling shroud during refueling with the in-core instrument thimble withdrawn is included in the radiation levels discussed in Section 12.2.

The shroud also minimizes the effects of external events such as jets from through-wall cracks in high- and moderate-energy pipes. The control rod drive mechanisms and small diameter piping, tubing and conduit within the shroud do not represent credible sources of missiles or jets due to breaks or cracks. Therefore, the shroud is not required to act as a missile shield to contain missiles generated within the integrated head package. It is also not required to deflect any jets originating within the integrated head package.

The cables and connectors, within the integrated head package, for the in-core instrumentation system are AP1000 equipment Class C, Class 1E. These cables are required to be physically and electrically independent of other cables including control rod drive mechanism power cables. Section 7.1 describes separation requirements. The cables and connector must be environmentally qualified, as discussed in Section 3.11. The cables are required to terminate at a connector plate located so that the cables can be readily connected or disconnected. The other cables within the integrated head package, including power cables and cables for the digital rod position indicator system, are not Class 1E.

The messenger tray provides seismic support and maintains separation for instrumentation and power cables when it is in the normal position spanning the space over the cavity from operating deck to the integrated head package.

3.9.7.2 Design Description

The integrated head package combines several separate components in one assembly to simplify refueling of the reactor. The purpose of the integrated head package is to reduce the outage time and personnel radiation exposure by combining operations associated with movement of the reactor vessel head during the refueling outage. In addition, the integrated head concept reduces the laydown space required in the containment. With the integrated head package, disconnections from and connections to the control rod drive mechanisms and rod position indicators (RPI) and other components within the cooling shroud assembly are not made at the individual component.

The integrated head package consists of the following main elements:

- Shroud assembly and cooling system
- Lifting system
- Mechanism seismic support structure
- Messenger tray and cable support structure
- Cables
- In-core instrumentation support structure

Brief descriptions of the principal elements of the integrated head package are provided in the following paragraphs.

Shroud assembly and cooling system - The cooling shroud is a carbon steel structure that encloses the control rod drive mechanisms above the reactor vessel head. During normal operation, it provides for the flow of cooling air to the control rod drive mechanism coil stacks. The rod position indicators are also cooled by this air flow. The air cooling fans and the duct work are integral with, and supported by, the shroud assembly. Structurally, the shroud is integrated with the head lifting system and the mechanism seismic support structure. The shroud also provides shielding at the vessel flange region.

The shroud structure is bolted to attachment lugs on the reactor vessel head, which also serve as the lifting attachment to the reactor vessel head. The shroud transfers the head load during a head lift to the control rod drive mechanism seismic support and into the lift rig.

Cabling, conduit and their supports and attachment hardware for the control rod drive mechanisms, control rod drive mechanism coil, cooling fans, in-core instrumentation is routed around the messenger tray attached to the shroud.

Lifting system - This apparatus lifts the reactor vessel head and integrated head package as a unit. The lifting system attaches to the mechanism seismic support structure. It consists of lift legs, sling block, clevises, and sling rods required to interface with the crane hook.

Mechanism seismic support structure - This structure provides seismic restraint for the mechanisms. It is located near the top of the control rod drive mechanism rod travel housings. The spike on the top of the control rod drive mechanism rod travel housing interfaces with this support. This support interfaces with the cooling shroud assembly to transfer seismic loads from the mechanisms to the reactor vessel head. In addition to this function, the mechanism seismic support structure acts as a spreader for the lift system and transfers the reactor vessel head loads to the lift system. The in-core instrument support structure is also supported from the mechanism seismic support structure.

Messenger tray and cable support structure - The messenger tray is located at an elevation above the top of the rod travel housings. It provides permanent support and routing for the control rod drive mechanism power cables, rod position indication cables, and in-core instrumentation cables which remain with the integrated head package and are normally not disturbed. These cables terminate at the connector plate, which constitutes the interface with the mating cables. Cable disconnects are made at the connector plate.

Cables - The integrated head package cables include those portions of the control rod drive mechanism power cables, in-core instrumentation, and rod position indication instrumentation cables extending from the connector plate, through the messenger tray and cooling shroud assembly to the user devices. These cables remain with the integrated head package and are normally not disturbed. The individual cables length are sized to provide an orderly arrangement in the messenger tray and inside the cooling shroud. For a refueling or other operation requiring movement of the integrated head package, the cables connected to the cables on the messenger tray are disconnected at a connector plate. The cables are then moved away from the integrated head package.

In-core instrumentation support structure (IISS) - The in-core instrumentation support structure is used during refueling operations. This support structure is used for withdrawing the in-core instrumentation thimble assemblies into the integrated head package. It protects and supports the thimble assemblies when they are in the fully withdrawn position. The in-core instrumentation system consists of thermocouples to measure fuel assembly coolant outlet temperature, and in-core flux thimbles containing fixed detectors for measurement of the neutron flux distribution within the reactor core. The incore thimble tubes have enhanced resistance to fluid-induced vibration and wear. The thimble is stiffer than the design in previous operating plants and the gap between the thimble tube and the tubes used to guide and protect the thimble inside the reactor vessel is smaller to minimize vibration. The potential for wear is also addressed by the material selection for the tube. The design of the thimble tube assembly also precludes an non-isolable leak of reactor coolant. The thermocouples and neutron detectors are routed through the integrated head package. These are inserted into the core through the reactor vessel head and upper internals assembly. Also, the in-core instrumentation support structure includes a platform which provides access to the in-core instrumentation during maintenance and refueling and to attach the lifting system to the crane hook.

3.9.7.3 Design Evaluation

The components of the integrated head package, which provide seismic support including the control rod drive mechanism seismic support and the shroud, are designed using the ASME Code,

Section III, Subsection NF. Because of the application of mechanistic pipe break evaluations, the supporting elements do not have to be designed for loads due to a postulated break in a reactor coolant loop pipe. Pipes down to 6-inch nominal diameter are evaluated using mechanistic pipe break criteria and the integrated head package is analyzed for movement of the reactor vessel due to a break of any pipe not qualified for leak-before-break. See subsection 3.6.3 for a discussion of the mechanistic pipe break requirements.

The integrated head package satisfies the limit on deflection of the top of the control rod drive mechanism rod travel housing. This limit restricts the bending moments on the control rod drive mechanisms to less than those that produce stress levels in the pressure boundary of the control rod drive mechanism greater than ASME Code limits during anticipated transient or postulated accident conditions. This deflection limit provides that the rod travel housing does not bend to the extent that the drive rod binds during insertion of the control rods. This limit is based on the results of drive line drop testing with control rod drives travel housings in deflected positions.

The components of the integrated head package included in the load path of the lifting rig are designed to satisfy the requirements for lifting of heavy loads in NUREG-0612 (Reference 10). The criteria of ANSI N14.6, (Reference 11) is used to evaluate the loads and stresses during a lift. See subsection 9.1.5 for discussion of special lifting rigs for heavy loads. Components which are part of the lifting load path are evaluated for the load due to the proof test required per ANSI N14.6.

Those cables and connectors for the in-core instrumentation system that are required to meet Class 1E requirements are evaluated for environmental conditions including normal operation and postulated accident conditions.

3.9.7.4 Inspection and Testing Requirements

The components in the lifting load path are proof tested to 150 percent of the rated load per the requirements of ANSI N14.6. The components load tested are surface examined by appropriate examination methods before and after the proof test.

3.9.8 Combined License Information

3.9.8.1 Reactor Internals Vibration Assessment and Predicted Response

Information including predicted vibration response and allowable response will be provided prior to the preoperational vibration testing of the first AP1000 consistent with the guidance of Regulatory Guide 1.20.

3.9.8.2 Design Specifications and Reports

Combined License applicants referencing the AP1000 design will have available for NRC audit the design specifications and design reports prepared for ASME Section III components. Combined License applicants will address consistency of the reactor vessel core support materials relative to known issues of irradiation-assisted stress corrosion cracking or void swelling (see subsection 4.5.2.1). [*The design report for the ASME Class 1, 2, and 3 piping will include the reconciliation of the as-built piping as outlined in subsection 3.9.3. This reconciliation includes*

verification of the thermal cycling and stratification loadings considered in the stress analysis discussed in subsection 3.9.3.1.2.]*

3.9.8.3 Snubber Operability Testing

Combined License applicants referencing the AP1000 design will develop a program to verify operability of essential snubbers as outlined in subsection 3.9.3.4.3.

3.9.8.4 Valve Inservice Testing

Combined License applicants referencing the AP1000 design will develop an inservice test program in conformance with the valve inservice test requirements outlined in subsection 3.9.6 and Table 3.9-16. This program will include provisions for nonintrusive check valve testing methods and the program for valve disassembly and inspection outlined in subsection 3.9.6.2.3. The Combined License applicant will complete an evaluation as identified in subsection 3.9.6.2.2 to demonstrate that power-operated valves with low differential pressure have adequate margin and operability testing of these valves is not required.

3.9.8.5 Surge Line Thermal Monitoring

A monitoring program will be implemented by the Combined License holder at the first AP1000 to record temperature distributions and thermal displacements of the surge line piping as outlined in subsection 3.9.3.1.2.

3.9.8.6 Piping Benchmark Program

The Combined License applicant will implement a benchmark program as described in subsection 3.9.1.2 if a piping analysis computer program other than one of those used for design certification is used. The piping benchmark problems identified in Reference 20 for the Westinghouse AP600 are also representative for the AP1000 and can be used for the AP1000 piping benchmark program if required.

3.9.9 References

1. ANS/ANSI N51.1-83, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants."

2. ANSI/ASME OM Code-1995 and 1996 Addenda, "Code for Operation and Maintenance of Nuclear Power Plants."

3. Kuenzel, A. J., "Westinghouse PWR Internals Vibrations Summary Three-Loop Internals Assurance," WCAP-7765-AR, November 1973.

4. Bloyd, C. N., Ciaramitaro, W., and Singleton, N. R., "Verification of Neutron Pad and 17 x 17 Guide Tube Designs by Preoperational Tests on the Trojan 1 Power Plant," WCAP-8766 (Proprietary) and WCAP-8780, (Nonproprietary), May 1976.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

5. Bloyd, C. N., and Singleton, N. R., "UHI Plant Internals Vibrations Measurement Program and Pre- and Post-Hot Functional Examinations," WCAP-8516-P (Proprietary) and WCAP-8517 (Nonproprietary), March 1975.

6. Abou-Jaude, K. F. and Nitkiewicz, J. S., "Doel 4 Reactor Internals Flow-Induced Vibration Measurement Program," WCAP-10846 (Proprietary), March 1985.

7. Bhandari, D. R. and Yu, C., "South Texas Plant (TGX) Reactor Internals Flow-Induced Vibration Assessment," WCAP-10865 (Proprietary) and WCAP-10866 (Nonproprietary), February 1985.

8. Takeuchi, K., et al., "Multiflex-A Fortran-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics," WCAP-8708-P-A, Volumes 1 and 2 (Proprietary) and WCAP-8709-A Volumes 1 and 2. (Nonproprietary), February 1976.

9. Cooper, F. W., Jr., "17 x 17 Drive Line Components Tests - Phase 1B 11, 111 D-Loop Drop and Deflection," WCAP-8446 (Proprietary) and WCAP-8449 (Nonproprietary), December 1974.

10. NUREG-0612, Control of Heavy Loads at Nuclear Power Plants, Nuclear Regulatory Commission, July 1980.

11. "Special Lifting Devices for Shipping Containers Weighing 10,000 Pounds (4500 kg) or More," ANSI N14.6.

12. NRC BULLETIN NO. 88-08: Thermal Stresses in Piping Connected to Reactor Coolant Systems, June 22, 1988, including Supplements 1, 2, and 3, dated: June 24, 1988; August 4, 1988; and April 11, 1989.

13. "A Comprehensive Vibration Assessment Program for Yonggwang Nuclear Generating Station, Final Evaluation of Pre-Core Hot Functional Measurement and Inspection Programs," CE Report 10487-ME-TE-240-03, August 22, 1995.

14. NRC BULLETIN NO. 88-11: Pressurizer Surge Line Thermal Stratification, December 20, 1988.

15. Deleted.

16. NRC IE Bulletin 79-13, "Cracking in Feedwater System Piping," June 25, 1979 and Revisions 1 and 2, dated August 30, 1979 and November 16, 1979.

17. "Investigation of Feedwater Line Cracking in Pressurized Water Reactor Plants," (Proprietary) WCAP-9693, June 1980.

18. "AP1000 Reactor Internals Flow-Induced Vibration Assessment Program," WCAP-15949-P (Proprietary) and WCAP-15949-NP (Nonproprietary), Revision 1, July 2003.

19. "Functional Capability of Piping Systems," NUREG-1367, Nuclear Regulatory Commission, November 1992.

20. "Piping Benchmark Problems for the Westinghouse AP600 Standardized Plant," NUREG/CR-6414 (BNL-NUREG-52487), Brookhaven National Laboratory, January 1997, Prepared for the U.S. Nuclear Regulatory Commission.

Table 3.9-1 (Sheet 1 of 2)

REACTOR COOLANT SYSTEM DESIGN TRANSIENTS

Event	Cycles
Level A Service Conditions	
Reactor coolant pump startup and shutdown (cycles of start and stop)	3000
Heatup at 100°F per hour	200
Cooldown at 100°F per hour	200
Unit loading between 0 and 15 percent of full power	500
Unit unloading between 0 and 15 percent of full power	500
Unit loading at 5 percent of full power per minute	19,800
Unit unloading at 5 percent of full power per minute	19,800
Step load increase of 10 percent of full power	3000
Step load decrease of 10 percent of full power	3000
Large step load decrease with steam dump	200
Steady-state fluctuation and load regulation	
Initial	1.5×10^5
Random	4.6×10^6
Load regulation	750,000
Boron concentration equalization	2900
Feedwater cycling at hot shutdown	
Mode 1	3000
Mode 2	15,000
Core lifetime extension	40
Feedwater heaters out of service	180
Refueling	40
Turbine roll test	20
Primary-side leakage test	200
Secondary-side leakage test	80
Core makeup tank high-pressure injection test	5
Passive residual heat removal tests	5
Reactor coolant system makeup	2820
Level B Service Conditions	
Loss of load (without reactor trip)	30
Loss of offsite power	30
Reactor trip from reduced power	180
Reactor trip from full power	
With no inadvertent cooldown	50
With cooldown and no safeguards actuation	50
With cooldown and PRHR actuation	20

Table 3.9-1 (Sheet 2 of 2)

REACTOR COOLANT SYSTEM DESIGN TRANSIENTS

Event	Cycles
Level B Service Conditions	
Control rod drop	
Case A	30
Cases B and C	30
Cold overpressure	15
Inadvertent safeguards actuation	10
Partial loss of reactor coolant flow	60
Inadvertent RCS depressurization	20
Excessive feedwater flow	30
Loss of offsite power - with natural circulation cooldown	
Case A - loss of power with natural circulation cooldown with onsite ac power	20
Case B - loss of power with natural circulation cooldown without onsite ac power	10
Level C Service Conditions	
Small loss of coolant accident	5
Small steam line break	5
Small feedwater line break	5
Steam generator tube rupture	5
Inadvertent opening of automatic depressurization system valves	15
Level D Service Conditions	
Reactor coolant pipe break (large loss-of-coolant accident)	1
Large steamline break	1
Large feedwater line break	1
Reactor coolant pump locked rotor	1
Control rod ejection	1
Test Conditions	
Primary side hydrotest	10
Secondary side hydrotest	10
Steam generator tube leakage test	
Secondary-side pressure, psig	
200	400
400	200
600	120
840	80

Table 3.9-2

PUMP STARTING/STOPPING CONDITIONS

Plant Condition	RCS (°F)/(psig)	SG Secondary (°F)/(psig)	Number of Starts/Stops	Operation
Cold	70/400	70/0	200	Cold Startup Transients
Cold	70/400	70/0	200	RCS heatup, cooldown
Restart	100/400	100/0	400	Hot functional RCP stops, starts
Hot(1)	557/2235	557/1091	1100	Transients and miscellaneous
Hot(2)	557/2235	557/1091	1100	Transients and miscellaneous

Notes:
1. First pump startup, last pump shutdown
2. Last pump startup, first pump shutdown

Table 3.9-3 (Sheet 1 of 2)

LOADINGS FOR ASME CLASS 1, 2, 3, CS AND SUPPORTS

Load	Description
P	Internal design pressure
PMAX	Peak pressure
DW	Dead weight
DML	Design Mechanical Loads (other than DW). This includes Service Level A loads and RVOS loads that are Service Level B.
XL	External mechanical loads, such as the nozzle reactions associated with piping systems, shall be combined with other loads in the loading combination expressions.
SSE	Safe shutdown earthquake (inertia portion)
E	Earthquake smaller than SSE (inertia portion)
FV	Fast valve closure
RVC	Relief/safety valve - closed system (transient)
RVOS	Relief/safety valve - open system (sustained)
RVOT	Relief/safety valve - open system (transient)
DY	Dynamic load associated with various service conditions including FV, RVC, and RVOT as applicable (transient)
DN	Dynamic load associated with Level A (Normal) service conditions including FV, RVC, and RVOT as applicable (transient)
DU	Dynamic load associated with Level B (Upset) service conditions including FV, RVC, and RVOT as applicable (transient)
DE	Dynamic load associated with Level C (Emergency) service conditions including FV, RVC, and RVOT as applicable (transient)
DF	Dynamic load associated with Level D (Faulted) service conditions during which, or following which, the piping system being evaluated must remain intact including FV, RVC, and RVOT as applicable. This includes postulated pipe rupture events (transient)
DYS	Dynamic load associated with various service conditions (sustained)
SSES	Seismic anchor motion portion of SSE
ES	Seismic anchor motion of earthquake smaller than SSE
TH	Thermal loads for the various service conditions

Table 3.9-3 (Sheet 2 of 2)

LOADINGS FOR ASME CLASS 1, 2, 3, CS AND SUPPORTS

Load	Description
TNU	Service Level A and B (normal and upset) plant condition thermal loads; including thermal stratification and thermal cycling
TN	Service Level A (normal) plant condition thermal loads
TU	Service Level B (upset) plant condition thermal loads
TE	Service Level C (emergency) plant condition thermal loads
TF	Service Level D (faulted) plant condition thermal loads
SCVNU	Static displacement of steel containment vessel - normal and upset conditions
SCVE	Static displacement of steel containment vessel - emergency condition
SCVF	Static displacement of steel containment vessel - faulted condition
HTDW	Hydrostatic test dead weight
DBPB	Design basis pipe break, includes LOCA and non-LOCA (transient)
LOCA	Loss-of-coolant accident
HYDSP	Building structure motions due to automatic depressurization system sparger discharge
DBPBS	Design basis pipe break, includes LOCA and non-LOCA (sustained)

Table 3.9-4

FIRST PLANT AP1000 REACTOR INTERNALS VIBRATION MEASUREMENT PROGRAM TRANSDUCER LOCATIONS

Instrumented Component	Number and Type of Transducers	Approximate Transducer Locations	Direction of Sensitivity
Core Shroud (Inner Wall)	4 accelerometers	0°, 180°, 225°, 270°	Radial
Core Shroud to Core Barrel	2 relative displacement transducers	0°	Radial
Core Barrel Flange (Outer Wall)	4 strain gages	0°, 90, 180°, 270°	Axial
Core Barrel Flange (Inner Wall)	2 strain gages	180°, 270°	Axial
Core Barrel Mid-elevation	3 accelerometers	0°, 180°, 225°	Radial
Core Barrel Mid-elevation	1 pressure transducer	0°	Radial
Upper Support Skirt (Inside and Outside)	3 strain gages	180°, 90° inside	Axial
Lower Core Support Plate Weld (Outside)	2 strain gages	0°, 90°	Vertical
Vortex Suppression Plate Support Columns (2)	4 strain gages or 4 accelerometers	On column near lower core support plate or On vortex suppression ring	Axial Horizontal
Reactor Vessel (Head Studs)	4 accelerometers	0°, 90°, 180°, 270°	Vertical
	3 accelerometers	0°, 90°, 180°	Horizontal
Support Column Extension	2 strain gages	0°, 90°	Axial
Guide Tube	4 strain gages	0°, 90°, 180°, 270°	Axial
Upper Support Column	4 strain gages	0°, 90°, 180°, 270°	Axial

Table 3.9-5

MINIMUM DESIGN LOADING COMBINATIONS FOR ASME CLASS 1, 2, 3 AND CS SYSTEMS AND COMPONENTS

Condition	Design Loading Combinations$^{(3)(6)}$
[*Design*	*P + DW + DML + XL*
Level A Service	*PMAX$^{(1)}$ + DW + XL$^{(4)}$*
	PMAX + DW + DN + XL$^{(8)}$
Level B Service	*PMAX + DW + DU + XL$^{(8)}$*
Level C Service	*PMAX + DW + DE$^{(5)}$ + XL$^{(8)}$*
	PMAX + DW + DY + HYDSP + XL$^{(9)}$
Level D Service	*PMAX + DW + DF + XL$^{(8)}$*
	PMAX + DW + SRSS$^{(2)}$ ((SSE + SSES) + DBPB)$^{(7)}$ + XL$^{(4)}$
	PMAX + DW + RVOS + SRSS (SSE + SSES)$^{(7)}$ + XL$^{(11)}$
	PMAX + DW + DYS + DBPBS + SRSS ((SSE + SSES)$^{(7)}$ + DY + HYDSP) + XL$^{(9)(10)}$]*

Notes:

1. The values of PMAX in the load combinations may be different for different levels of service conditions as provided in the design transients. For earthquake loadings PMAX is equal to normal operating pressure at 100% power.
2. SRSS equals the square root of the sum of the squares.
3. Appropriate loads due to static displacements of the steel containment vessel and building settlement should be added to the loading combinations expressions for ASME Code, Section III, Class 2 and 3 systems.
4. In combining loads, the timing and causal relationships that exist between PMAX, and XL, are considered for determination of the appropriate load combinations.
5. The pressurizer safety valve discharge is a Level C service condition.
6. See Table 3.9-3 for description of loads.
7. For components that behave as anchors to the piping system, such as equipment nozzles, SSE and SSES are combined by absolute sum. For other components, such as straight pipe, tees, and valves, SSE and SSES are combined by SRSS method.
8. In combining loads, the timing and causal relationships that exist between PMAX, DN, DU, DE, DF, and XL, are considered for determination of the appropriate load combinations.
9. In combining loads, the timing and causal relationships that exist between PMAX, DY, HYDSP, and XL, are considered for determination of the appropriate load combinations.
10. In combining loads, the timing and causal relationships that exist between PMAX, DY, and XL, are considered for determination of the appropriate load combinations.
11. In combining loads, the timing and causal relationships that exist between PMAX, RVOS, and XL, are considered for determination of the appropriate load combinations.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.9-6

ADDITIONAL LOAD COMBINATIONS AND STRESS LIMITS FOR ASME CLASS 1 PIPING

Condition	Loads(7)	Equation (NB3650)	Stress Limit
[*Level A/B*	*PMAX(1), TNU, E, ES, RVC, DN, DU, SCVNU(2)(4)(5)* *RVOS(2)*	*10* *11, 14*	*3.0* S_m *CUF = 1.0*
	TNU	*12*	*3.0* S_m
	PMAX + DW + DU *PMAX + DW + RVOS(2)*	*13* *13*	*3.0* S_m *3.0* S_m
Level C	*TE + SCVE*	*Note 3*	*Note 3*
Level D(8)	*SSES* *TF + SCVF* *TNU + SSES*	F_{AM}/A_M(6) *Note 3* C_2D_o *(M1 + M2)/2I(8)*	*1.0* S_m *Note 3* *6.0* S_m]*

Notes:

1. The values of PMAX in the load combinations may be different for different levels of service conditions. For earthquake loading, PMAX is equal to normal operating pressure at 100% power.
2. Pressurizer safety valve discharge is classified as a Level C event.
3. See Table 3.9-11 for functional capability requirements.
4. The earthquake loads are assumed to occur at normal 100 percent power operation for the purposes of determining the total moment ranges.
5. Square root sum of the squares (SRSS) combination is used for ES, E, and other transient loads.
6. F_{AM} is amplitude of axial force for SSES; A_M is nominal pipe metal area.
7. See Table 3.9-3 for description of loads.
8. Where: M1 is range of moments for TNU, M2 is one half the range of SSES moments,
   M1 + M2 is larger of M1 plus one half the range of SSES, or full range of SSES
   C_2, D_o, I based on ASME III

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.9-7

ADDITIONAL LOAD COMBINATIONS AND STRESS LIMITS FOR ASME CLASS 2, 3 PIPING

Condition	Loads[3]	Equation (NC/ND3650)	Stress Limit
[*Level A/B*	*PMAX*[1] *+ DW + TNU + SCVNU*[4]	*11*	$S_h + S_A$
	Building Settlement	*10a*	$3.0\ S_C$
Level C	*TE + SCVE*[4]	*Note 6*	*Note 6*
Level D	*TNU + SSES*	$i\ (M1 + M2)/Z$[2]	$3.0\ S_h$
	SSES	F_{AM}/A_M[5]	$1.0\ S_h$
	TF + SCVF[4]	*Note 6*	*Note 6*]*

Notes:

1. The values of PMAX in the load combinations may be different for different levels of service conditions. For earthquake loading PMAX is equal to normal operating pressure at 100% power.
2. Where: M1 is range of moments for TNU, M2 is one half the range of SSES moments, M1 + M2 is larger of M1 plus one half the range of SSES, or full range of SSES
3. See Table 3.9-3 for description of loads.
4. The timing and causal relationships among TNU, TE, TF, SCVNU, SCVE, and SCVF are considered to determine appropriate load combinations.
5. F_{AM} is amplitude of axial force for SSES; A_M is nominal pipe metal area.
6. See Table 3.9-11 for functional capability requirements.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.9-8

MINIMUM DESIGN LOADING COMBINATIONS FOR SUPPORTS FOR ASME CLASS 1, 2, 3 PIPING AND COMPONENTS(2)

Condition	Design Loading Combinations(3)
[*Design*	*DW + DML*
Level A Service	*DW + TH + DN(4)*
Level B Service	*DW + TH + DU(4)*
Level C Service	*DW + TH + DE(5)(4)*
	DW + TH + DY + HYDSP(7)
Level D Service	*DW + TH + RVOS + SSE + SSES + SWE(6)(8)*
	DW + TH + DF(4)
	DW + TH + SRSS (DBPB + (SSE + SSES + SWE))(6)
	DW + TH + DYS + DBPBS + SRSS ((SSE + SSES + SWE)(6) + DY + HYDSP)(7)(9)
Hydrostatic Test	*HTDW*]*

Notes:

1. SRSS - square root of the sum of the squares
2. Appropriate loads due to static displacement of the steel containment vessel and building settlement should be added to the loading combinations expressions for Class 2 and 3 systems.
3. See Table 3.9-3 for description of loads.
4. The timing and causal relationships between TH and DY are considered to determine appropriate load combinations.
5. The pressurizer safety valve discharge is a Level C Service condition.
6. Combine SSE, SSES, and SWE by absolute sum method. SWE is self weight excitation, the effect of the acceleration of the support mass caused by building filtered loads such as SSE.
7. In combining loads, the timing and causal relationships that exist among TH, DY, and HYDSP are considered for determination of the appropriate load combinations.
8. In combining loads, the timing and causal relationships that exist among TH and RVOS are considered for determination of the appropriate load combinations.
9. In combining loads, the timing and causal relationships that exist among TH and DY are considered for determination of the appropriate load combinations.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.9-9

STRESS CRITERIA FOR ASME CODE SECTION III CLASS 1 COMPONENTS[(a)] AND SUPPORTS AND CLASS CS CORE SUPPORTS

Design/Service Level	Vessels/Tanks Pumps	Piping (h)	Core Supports	Valves, Disks & Seats	Components Supports [(c,d)]
Design and Service Level A	ASME Code, Section III NB-3221, 3222	[*ASME Code, Section III NB-3652, Equation 9*]*	ASME Code, Section III NG-3221, 3222, 3231, 3232	ASME Code, Section III NB-3520, 3525	[*ASME Code, Section III Subsection NF (e)*]*
Service Level B (Upset)	ASME Code, Section III NB-3223	[*ASME Code, Section III NB-3654, Equation 9*]*	ASME Code, Section III NG-3223, 3233	ASME Code, Section III NB-3525	[*ASME Code, Section III Subsection NF (e)*]*
Service Level C (Emergency)	ASME Code, Section III NB-3224	[*ASME Code, Section III NB-3655, Equation 9*]*	ASME Code, Section III NG-3224, 3234	ASME Code, Section III NB-3526	[*ASME Code, Section III Subsection NF (e)*]*
Service Level D (Faulted)	ASME Code, Section III (see Chapter 3.9.1.4) NB-3225 (no active Class 1 pumps used)	[*ASME Code, Section III NB-3656, Equation 9*]*	ASME Code, Section III (see chapter 3.9.1) NG-3225, 3235	(b) (g)	[*ASME Code, Section III Subsection NF, (e) (see Chapter 3.9.1) (f)*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Notes:

a. A test of the components may be performed in lieu of analysis.

b. Class 1 valve service Level D criteria for inactive valves is based on the criteria in ASME III, Appendix F, F-1420 for verification of pressure boundary integrity.

c. Including pipe supports.

d. In instances where the determination of allowable stress values utilizes S_u (ultimate tensile stress) at temperatures not included in ASME Code Section III, S_u shall be calculated using one of the methods provided in Regulatory Guide 1.124, Revision 1.

e. ASME Table 3131(a)-1.

f. See subsection 3.9.3.4 for supports for active equipment, valves, and piping with active valves.

g. For active valves, pressure integrity verification will be based on using the ASME Code allowables one level less than the service loading condition. For example, for the evaluation of Level D loading, Level C allowables will be used. Valve operability is demonstrated by testing or analysis. Check valve operability may be shown by analysis. See subsection 3.9.3.2.2 for an outline of test requirements.

h. Table 3.9-6 includes additional stress limits for Class 1 piping.

Table 3.9-10

STRESS CRITERIA FOR ASME CODE SECTION III CLASS 2 AND 3 COMPONENTS AND SUPPORTS

Design/ Service Level	**Vessels/Tanks**	**Piping (f)**	**Pumps**	**Valves, Disks, Seats**	**Component Supports (a) (b)**
Design and Service Level A	ASME Code Section III NC-3217 NC/ ND-3310, 3320	[*ASME Code, Section III NC/ND-3652, Equation 8*]*	ASME Code Section III NC/ND-3400	ASME Code Section III NC/ND-3510	[*ASME Code Section III (c)*]*
Service Level B (Upset)	ASME Code Section III NC/ND-3310, 3320	[*ASME Code, Section III NC/ND-3653, Equation 9*]*	ASME Code Section III NC/ND-3400	ASME Code Section III NC/ND-3520	[*ASME Code Section III (c)*]*
Service Level C (Emergency)	ASME Code Section III NC/ND-3310, 3320	[*ASME Code, Section III NC/ND-3654, Equation 9*]*	ASME Code Section III NC/ND-3400	ASME Code Section III NC/ND-3520	[*ASME Code Section III (c)*]*
Service Level D (Faulted)	ASME Code Section III NC/ND-3310, 3320	[*ASME Code, Section III NC/ND-3655, Equation 9*]*	ASME Code Section III NC/ND-3400	ASME Code Section III NC/ND-3520 (e)	[*ASME Code Section III (c) (d)*]*

See following page for notes.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Notes:

a. Including pipe supports.

b. In instances where the determination of allowable stress values utilizes S_u (ultimate tensile stress) at temperatures not included in ASME Code Section III, S_u shall be calculated using one of the methods provided in Regulatory Guide 1.124, Revision 1.

c. ASME Table 3131(a)-1.

d. See subsection 3.9.3.4 for supports for active equipment, valves, and piping with active valves.

e. For active valves, pressure integrity verification will be based on using the ASME Code allowables one level less than the service loading condition. For example, for the evaluation of Level D loading, Level C allowables will be used. Valve operability is demonstrated by testing or analysis. Check valve operability may be shown by analysis. See subsection 3.9.3.2.2 for an outline of test requirements.

f. Table 3.9-7 includes additional stress limits for Class 2 and 3 piping.

Table 3.9-11

PIPING FUNCTIONAL CAPABILITY – ASME CLASS 1, 2, AND 3[1]

[*Wall Thickness:*	$D_o/t \le 50$, *where* D_o, *t are per ASME III*
Service Level D Conditions	*Equation 9* $\le$ *smaller of 2.0* S_y *and 3.0* S_m (2, 4, 5) *Equation 9* $\le$ *smaller of 2.0* S_y *and 3.0* S_h (3, 4, 6)
External Pressure:	$P_{external} \le P_{internal}$
TE + SCVE	$C2*M*D_o/2I \le 6.0\ S_m$ (2) *(NB-3650)* *Equation 10a (NC3653.2)* $\le 3.0\ S_c$ (3)
TF + SCVF	$C2*M*D_o/2I \le 6.0\ S_m$ (2) *(NB-3650)* *Equation 10a (NC 3653.2)* $\le 3.0\ S_c$ (3]*

Notes:

1. Applicable to Level C or Level D plant events for which the piping system must maintain an adequate fluid flow path
2. Applicable to ASME Code Class 1 piping
3. Applicable to ASME Code Class 2 and 3 piping
4. Applicable to ASME Code Class 1, 2 and 3 piping when the following limitations are met:

   4.1 Dynamic loads are reversing (slug-flow water hammer loads are non-reversing)

   4.2 Slug-flow water-hammer loads are combined with other design basis loads (for example: SSE; pipe break loads)

   4.3 Steady-state bending stress from deadweight loads does not exceed:

$$\frac{B2*M}{Z} \le 0.25\, S_Y$$

   4.4 When elastic response spectrum analysis is used, dynamic moments are calculated using 15% peak broadening and not more than 5% damping

5. For Class 1 piping, when slug-flow water hammer loads are only combined with pressure, weight and other sustained mechanical loads, the Equation 9 stress does not exceed the smaller of 1.8 S_y and 2.25 S_m.
6. For Class 2 and 3 piping, when slug-flow water hammer loads are only combined with pressure, weight and other sustained mechanical loads, the Equation 9 stress does not exceed the smaller of 1.8 S_y and 2.25 S_h.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3.9-12 (Sheet 1 of 7)

LIST OF ASME CLASS 1, 2, AND 3 ACTIVE VALVES

Valve No.	Description	Function[(a)]
Compressed Air System		
CAS-PL-V014	Instrument Air Supply Outside Containment Isolation	2
CAS-PL-V015	Instrument Air Supply Inside Containment Isolation Check Valve	2
Component Cooling Water System		
CCS-PL-V200	Containment Isolation Valve – Inlet Line Isolation	2
CCS-PL-V201	Containment Isolation Valve – Inlet Line Check Valve	2
CCS-PL-V207	Containment Isolation Valve – Outlet Line Isolation	2
CCS-PL-V208	Containment Isolation Valve – Outlet Line Isolation	2
Chemical and Volume Control System		
CVS-PL-V001	Reactor Coolant System Purification Stop	1
CVS-PL-V002	Reactor Coolant System Purification Stop	1
CVS-PL-V003	Reactor Coolant System Purification Stop	1
CVS-PL-V042	Flush Line Containment Isolation Relief	2
CVS-PL-V045	Letdown Containment Isolation IRC	2
CVS-PL-V047	Letdown Containment Isolation ORC	2
CVS-PL-V080	Reactor Coolant System Purification Return Line Check Valve	1
CVS-PL-V081	Reactor Coolant System Purification Return Line Stop Valve	1
CVS-PL-V082	Reactor Coolant System Purification Return Line Check Valve	1
CVS-PL-V084	Auxiliary Pressurizer Spray Line Isolation	1
CVS-PL-V085	Auxiliary Pressurizer Spray Line Check Valve	1
CVS-PL-V090	Makeup Line Containment Isolation	2
CVS-PL-V091	Makeup Line Containment Isolation	2
CVS-PL-V092	Hydrogen Add Containment Isolation	2
CVS-PL-V094	Hydrogen Add IRC Isolation Check Valve	2
CVS-PL-V100	Makeup Line Containment Isolation Thermal Relief Check Valve	2
CVS-PL-V136A	Demineralized Water System Isolation	3
CVS-PL-V136B	Demineralized Water System Isolation	3
Fuel Handing System		
FHS-PL-V001	Fuel Transfer Tube Isolation Valve	3
Passive Containment Cooling System		
PCS-PL-V001A	Passive Containment Cooling Water Storage Tank Isolation	3,4
PCS-PL-V001B	Passive Containment Cooling Water Storage Tank Isolation	3,4
PCS-PL-V001C	Passive Containment Cooling Water Storage Tank Isolation	3,4
PCS-PL-V002A	Passive Containment Cooling Water Storage Tank Series Isolation	3,4
PCS-PL-V002B	Passive Containment Cooling Water Storage Tank Series Isolation	3,4
PCS-PL-V002C	Passive Containment Cooling Water Storage Tank Series Isolation	3,4

Table 3.9-12 (Sheet 2 of 7)

LIST OF ASME CLASS 1, 2, AND 3 ACTIVE VALVES

Valve No.	Description	Function[(a)]
Passive Containment Cooling System (Cont.)		
PCS-PL-V005	Passive Containment Cooling Water Storage Tank Supply to Fire Protection System Isolation Manual Stop-Check Valve	3,4
PCS-PL-V009	Spent Fuel Pool Emergency Makeup Isolation	3
PCS-PL-V015	Water Bucket Makeup Line Drain Valve	3,4
PCS-PL-V020	Water Bucket Makeup Line Isolation Valve	3,4
PCS-PL-V023	PCS Recirculation Return Isolation Manual Stop Check Valve	3,4
PCS-PL-V039	PCCWST Long-Term Makeup Check Valve	3,4
PCS-PL-V042	PCCWST Long Term Makeup Isolation Drain Valve	3,4
PCS-PL-V044	PCCWST Long Term Makeup Isolation Valve	3,4
PCS-PL-V045	Emergency Makeup to the Spent Fuel Pool Isolation Valve	3
PCS-PL-V046	PCCWST Recirculation Return Isolation Valve	3,4
PCS-PL-V049	Emergency Makeup to the Spent Fuel Pool Drain Isolation Valve	3
PCS-PL-V050	Spent Fuel Pool Long Term Makeup Isolation Valve	3
PCS-PL-V051	Spent Fuel Pool Emergency Makeup Lower Isolation Valve	3
Primary Sampling System		
PSS-PL-V008	Containment Isolation – Containment Air Sample Isolation	2
PSS-PL-V010A	Containment Isolation – Liquid Sample Line	2
PSS-PL-V010B	Containment Isolation – Liquid Sample Line	2
PSS-PL-V011	Containment Isolation – Liquid Sample Line	2
PSS-PL-V023	Containment Isolation – Sample Return Line	2
PSS-PL-V024	Containment Isolation – Sample Return Check	2
PSS-PL-V046	Containment Isolation – Air Sample Line	2
Passive Core Cooling System		
PXS-PL-V014A	Core Makeup Tank A Discharge Isolation	3,4
PXS-PL-V014B	Core Makeup Tank B Discharge Isolation	3,4
PXS-PL-V015A	Core Makeup Tank A Discharge Isolation	3,4
PXS-PL-V015B	Core Makeup Tank B Discharge Isolation	3,4
PXS-PL-V016A	Core Makeup Tank A Discharge Check	3,4
PXS-PL-V016B	Core Makeup Tank Discharge Check	3,4
PXS-PL-V017A	Core Makeup Tank A Discharge Check	3,4
PXS-PL-V017B	Core Makeup Tank B Discharge Check	3,4
PXS-PL-V022A	Accumulator A Pressure Relief	3
PXS-PL-V022B	Accumulator B Pressure Relief	3
PXS-PL-V028A	Accumulator A Discharge Check	1,3,4
PXS-PL-V028B	Accumulator B Discharge Check	1,3,4

Table 3.9-12 (Sheet 3 of 7)

LIST OF ASME CLASS 1, 2, AND 3 ACTIVE VALVES

Valve No.	Description	Function[(a)]
Passive Core Cooling System (Cont.)		
PXS-PL-V029A	Accumulator A Discharge Check	1,3,4
PXS-PL-V029B	Accumulator B Discharge Check	1,3,4
PXS-PL-V042	Nitrogen Supply Containment Isolation ORC Isolation Valve	2
PXS-PL-V043	Nitrogen Supply Containment Isolation IRC Check Valve	2
PXS-PL-V108A	Passive Residual Heat Removal Heat Exchanger Control	3,4
PXS-PL-V108B	Passive Residual Heat Removal Heat Exchanger Control	3,4
PXS-PL-V117A	Recirculation Sump A Isolation	3,4
PXS-PL-V117B	Recirculation Sump B Isolation	3,4
PXS-PL-V118A	Recirculation Sump A Isolation	3,4
PXS-PL-V118B	Recirculation Sump B Isolation	3,4
PXS-PL-V119A	Recirculation Sump A Check	3,4
PXS-PL-V119B	Recirculation Sump B Check	3,4
PXS-PL-V120A	Recirculation Sump A Isolation	3,4
PXS-PL-V120B	Recirculation Sump B Isolation	3,4
PXS-PL-V122A	In-Containment Refueling Water Storage Tank Injection A Check	1,3,4
PXS-PL-V122B	In-Containment Refueling Water Storage Tank Injection B Check	1,3,4
PXS-PL-V123A	In-Containment Refueling Water Storage Tank Injection A Isolation	1,3,4
PXS-PL-V123B	In-Containment Refueling Water Storage Tank Injection B Isolation	1,3,4
PXS-PL-V124A	In-Containment Refueling Water Storage Tank Injection A Check	1,3,4
PXS-PL-V124B	In-Containment Refueling Water Storage Tank Injection B Check	1,3,4
PXS-PL-V125A	In-Containment Refueling Water Storage Tank Injection A Isolation	1,3,4
PXS-PL-V125B	In-Containment Refueling Water Storage Tank Injection B Isolation	1,3,4
PXS-PL-130A	In-Containment Refueling Water Storage Tank Gutter Isolation	3,4
PXS-PL-130B	In-Containment Refueling Water Storage Tank Gutter Isolation	3,4
Reactor Coolant System		
RCS-PL-V001A	First Stage Automatic Depressurization System	1,3,4
RCS-PL-V001B	First Stage Automatic Depressurization System	1,3,4
RCS-PL-V002A	Second Stage Automatic Depressurization System	1,3,4
RCS-PL-V002B	Second Stage Automatic Depressurization System	1,3,4
RCS-PL-V003A	Third Stage Automatic Depressurization System	1,3,4
RCS-PL-V003B	Third Stage Automatic Depressurization System	1,3,4
RCS-PL-V004A	Fourth Stage Automatic Depressurization System	1,3,4
RCS-PL-V004B	Fourth Stage Automatic Depressurization System	1,3,4
RCS-PL-V004C	Fourth Stage Automatic Depressurization System	1,3,4
RCS-PL-V004D	Fourth Stage Automatic Depressurization System	1,3,4

Table 3.9-12 (Sheet 4 of 7)

LIST OF ASME CLASS 1, 2, AND 3 ACTIVE VALVES

Valve No.	Description	Function[(a)]
Reactor Coolant System (Cont.)		
RCS-PL-V005A	Pressurizer Safety Valve	1,3
RCS-PL-V005B	Pressurizer Safety Valve	1,3
RCS-PL-V010A	Automatic Depressurization System Discharge Header A Vacuum Relief	3
RCS-PL-V010B	Automatic Depressurization System Discharge Header B Vacuum Relief	3
RCS-PL-V011A	First Stage Automatic Depressurization System Isolation	1,3,4
RCS-PL-V011B	First Stage Automatic Depressurization System Isolation	1,3,4
RCS-PL-V012A	Second Stage Automatic Depressurization System Isolation	1,3,4
RCS-PL-V012B	Second Stage Automatic Depressurization System Isolation	1,3,4
RCS-PL-V013A	Third Stage Automatic Depressurization System Isolation	1,3,4
RCS-PL-V013B	Third Stage Automatic Depressurization System Isolation	1,3,4
RCS-PL-V150A	Reactor Vessel Head Vent	1,3
RCS-PL-V150B	Reactor Vessel Head Vent	1,3
RCS-PL-V150C	Reactor Vessel Head Vent	1,3
RCS-PL-V150D	Reactor Vessel Head Vent	1,3
Normal Residual Heat Removal System		
RNS-PL-V001A	Reactor Coolant System Inner HL Suction Isolation	1
RNS-PL-V001B	Reactor Coolant System Inner HL Suction Isolation	1
RNS-PL-V002A	Reactor Coolant System Outer HL Suction Isolation	1,2
RNS-PL-V002B	Reactor Coolant System Outer HL Suction Isolation	1,2
RNS-PL-V003A	Reactor Coolant System Pressure Boundary Valve Thermal Relief Check Valve	1
RNS-PL-V003B	Reactor Coolant System Pressure Boundary Valve Thermal Relief Check Valve	1
RNS-PL-V011	RNS Discharge Containment Isolation Valve	2
RNS-PL-V013	RNS Discharge Containment Isolation Check Valve	2
RNS-PL-V015A	RNS Discharge Reactor Coolant System Pressure Boundary	1
RNS-PL-V015B	RNS Discharge Reactor Coolant System Pressure Boundary	1
RNS-PL-V017A	RNS Discharge Reactor Coolant System Pressure Boundary	1
RNS-PL-V017B	RNS Discharge Reactor Coolant System Pressure Boundary	1
RNS-PL-V021	RNS HL Suction Pressure Relief	2
RNS-PL-V022	RNS Suction Header Containment Isolation	2
RNS-PL-V023	RNS Suction from In-Containment Refueling Water Storage Tank Isolation	2
RNS-PL-V046	RNS Heat Exchanger A Channel Head Drain Manual Isolation Valve	3,4
RNS-PL-V045	RNS Pump Discharge Pressure Relief	1
RNS-PL-V061	RNS – Chemical Volume Control System Containment Isolation	2

Table 3.9-12 (Sheet 5 of 7)

LIST OF ASME CLASS 1, 2, AND 3 ACTIVE VALVES

Valve No.	Description	Function[(a)]
Spent Fuel Pool Cooling System		
SFS-PL-V034	Spent Fuel Pool Cooling System Suction Line Containment Isolation	2
SFS-PL-V035	Spent Fuel Pool Cooling System Suction Line Containment Isolation	2
SFS-PL-V037	Spent Fuel Pool Cooling System Discharge Line Containment Isolation	2
SFS-PL-V038	Spent Fuel Pool Cooling System Discharge Line Containment Isolation	2
SFS-PL-V066	Spent Fuel Pool to Cask Washdown Pit Isolation	3
SFS-PL-V068	Cask Washdown Pit Drain Isolation	3
SFS-PL-V071	Refueling Cavity to Steam Generator Compartment	3
SFS-PL-V072	Refueling Cavity to Steam Generator Compartment	3
Steam Generator System		
SGS-PL-V027A	Power Operated Relief Valve Block Valve Steam Generator 01	2,3,4
SGS-PL-V027B	Power Operated Relief Valve Block Valve Steam Generator 02	2,3,4
SGS-PL-V030A	Main Steam Safety Valve Steam Generator 01	2,3,4
SGS-PL-V030B	Main Steam Safety Valve Steam Generator 02	2,3,4
SGS-PL-V031A	Main Steam Safety Valve Steam Generator 01	2,3,4
SGS-PL-V031B	Main Steam Safety Valve Steam Generator 02	2,3,4
SGS-PL-V032A	Main Steam Safety Valve Steam Generator 01	2,3,4
SGS-PL-V032B	Main Steam Safety Valve Steam Generator 02	2,3,4
SGS-PL-V033A	Main Steam Safety Valve Steam Generator 01	2,3,4
SGS-PL-V033B	Main Steam Safety Valve Steam Generator 02	2,3,4
SGS-PL-V034A	Main Steam Safety Valve Steam Generator 01	2,3,4
SGS-PL-V034B	Main Steam Safety Valve Steam Generator 02	2,3,4
SGS-PL-V035A	Main Steam Safety Valve Steam Generator 01	2,3,4
SGS-PL-V035B	Main Steam Safety Valve Steam Generator 02	2,3,4
SGS-PL-V036A	Steam Line Condensate Drain Isolation	2,3,4
SGS-PL-V036B	Steam Line Condensate Drain Isolation	2,3,4
SGS-PL-V040A	Main Steam Line Isolation	2,3,4
SGS-PL-V040B	Main Steam Line Isolation	2,3,4
SGS-PL-V057A	Main Feedwater Isolation	2,3,4
SGS-PL-V057B	Main Feedwater Isolation	2,3,4
SGS-PL-V067A	Startup Feedwater Isolation	2,3,4
SGS-PL-V067B	Startup Feedwater Isolation	2,3,4
SGS-PL-V074A	Steam Generator Blowdown Isolation	2,3,4
SGS-PL-V074B	Steam Generator Blowdown Isolation	2,3,4

Table 3.9-12 (Sheet 6 of 7)

LIST OF ASME CLASS 1, 2, AND 3 ACTIVE VALVES

Valve No.	Description	Function[(a)]
Steam Generator System (Cont.)		
SGS-PL-V075A	Steam Generator Series Blowdown Isolation	3,4
SGS-PL-V075B	Steam Generator Series Blowdown Isolation	3,4
SGS-PL-V086A	Steam Line Condensate Drain Control	3,4
SGS-PL-V086B	Steam Line Condensate Drain Control	3,4
SGS-PL-V233A	Power Operated Relief Valve	3,4
SGS-PL-V233B	Power Operated Relief Valve	3,4
SGS-PL-V240A	Main Steam Isolation Valve Bypass Isolation	2,3,4
SGS-PL-V240B	Main Steam Isolation Valve Bypass Isolation	2,3,4
SGS-PL-V250A	Main Feedwater Control	3,4
SGS-PL-V250B	Main Feedwater Control	3,4
SGS-PL-V255A	Startup Feedwater Control	3,4
SGS-PL-V255B	Startup Feedwater Control	3,4
Nuclear Island Nonradioactive Ventilation System		
VBS-PL-V186	MCR Supply Air Isolation Valve	3
VBS-PL-V187	MCR Supply Air Isolation Valve	3
VBS-PL-V188	MCR Return Air Isolation Valve	3
VBS-PL-V189	MCR Return Air Isolation Valve	3
VBS-PL-V190	MCR Exhaust Air Isolation Valve	3
VBS-PL-V191	MCR Exhaust Air Isolation Valve	3
Main Control Room Habitability System		
VES-PL-V002A	Pressure Regulating Valve A	3
VES-PL-V002B	Pressure Regulating Valve B	3
VES-PL-V005A	Air Delivery Isolation Valve A	3
VES-PL-V005B	Air Delivery Isolation Valve B	3
VES-PL-V008A	Refill Check Valve A	3
VES-PL-V008B	Refill Check Valve B	3
VES-PL-V022A	Pressure Relief Isolation Valve A	3
VES-PL-V022B	Pressure Relief Isolation Valve B	3
VES-PL-V040A	Air Tank Safety Relief Valve A	3
VES-PL-V040B	Air Tank Safety Relief Valve B	3
VES-PL-V041A	Air Tank Safety Relief Valve A	3
VES-PL-V041B	Air Tank Safety Relief Valve B	3
VES-PL-V042	Refill Header Manual Vent Valve	3

Table 3.9-12 (Sheet 7 of 7)

LIST OF ASME CLASS 1, 2, AND 3 ACTIVE VALVES

Valve No.	Description	Function[a]
Containment Air Filtration System		
VFS-PL-V003	Containment Purge Inlet Containment Isolation Valve	2
VFS-PL-V004	Containment Purge Inlet Containment Isolation Valve	2
VFS-PL-V009	Containment Purge Discharge Containment Isolation Valve	2
VFS-PL-V010	Containment Purge Discharge Containment Isolation Valve	2
Central Chilled Water System		
VWS-PL-V058	Fan Coolers Supply Containment Isolation	2
VWS-PL-V062	Fan Coolers Supply Containment Isolation Check Valve	2
VWS-PL-V082	Fan Coolers Return Containment Isolation	2
VWS-PL-V086	Fan Coolers Return Containment Isolation	2
Liquid Radwaste System		
WLS-PL-V055	Sump Containment Isolation IRC	2
WLS-PL-V057	Sump Containment Isolation ORC	2
WLS-PL-V067	Reactor Coolant Drain Tank Gas Containment Isolation IRC	2
WLS-PL-V068	Reactor Coolant Drain Tank Gas Containment Isolation ORC	2
WLS-PL-V071A	Chemical and Volume Control System Compartment to Sump	3
WLS-PL-V071B	Passive Core Cooling System A Compartment to Sump	3
WLS-PL-V071C	Passive Core Cooling System B Compartment to Sump	3
WLS-PL-V072A	Chemical and Volume Control System Compartment to Sump	3
WLS-PL-V072B	Passive Core Cooling System A Compartment to Sump	3
WLS-PL-V072C	Passive Core Cooling System B Compartment to Sump	3

Note:
a. Function: 1 – Reactor coolant system pressure boundary
2 – Containment isolation
3 – Accident mitigation
4 – Safe shutdown

Table 3.9-13

CONTROL ROD DRIVE MECHANISM PRODUCTION TESTS

Test	Acceptance Standard
Cold (ambient) hydrostatic	ASME Code, Section III
Confirm step length and load transfer (stationary gripper to movable gripper or movable gripper to stationary gripper)	Step length: 0.625+0.015 inch axial movement Load transfer: 0.055 inch nominal axial movement
Cold (ambient) performance test at design load - five full travel excursions	Operating speed: 45 inches/minute Trip delay: Free fall of drive rod to begin within 150 milliseconds

Table 3.9-14

MAXIMUM DEFLECTIONS ALLOWED FOR REACTOR INTERNAL SUPPORT STRUCTURES

Component	Allowable Deflections (in.)
Upper Core Barrel	
Radial inward (uniform)	4.1
Radial outward (uniform)(1)	1.0
Upper package – relative vertical motion between upper core plate and upper support plate	0.20
Rod cluster guide tubes – radial toward the reactor vessel outlet	1.00

Note:
1. Non-uniform radial outward deflections are limited such that > 90-percent of the annulus area is maintained.

Table 3.9-15

COMPUTER PROGRAMS FOR SEISMIC CATEGORY 1 COMPONENTS

Program	Application
ABAQUS	Finite element structural analysis
ANSYS	Finite element structural analysis
FATCON	ASME fatigue analysis of piping components
GAPPIPE	Static and dynamic analysis of piping systems
MAXTRAN	Transient stress evaluation of piping components
PIPESTRESS	Static and dynamic analysis of piping systems
PIPSAN	Structural and ASME stress analysis of component supports
STAAD-III	Static and dynamic analysis of structural frames
THERST	Transient heat transfer analysis of piping components
WECAN	Finite element structural analysis
WEGAP	Dynamic structural response of the reactor core
WECEVAL	ASME stress evaluation of mechanical components
ITCH	Transient hydraulic analysis
FORFUN	Computes unbalanced hydraulic forces between piping elbows
RELAP-5	Transient dynamic analysis
THRUST	Computes time-history hydraulic forcing functions
MULTIFLEX	Thermal-hydraulic-structural system analysis
MULTIFLEX-SG	Transient dynamic analysis
GEC2	Computes time-history hydraulic forcing functions
FATSTR	ASME stress evaluation of piping components
HSTA	Hydraulic system transient analysis
E0781	Axisymmetric containment shell analysis
FLOW 3D	Finite element fluid flow and heat transfer

Table 3.9-16 (Sheet 1 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description(1)	Valve Type	Safety-Related Missions	Safety Functions(2)	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
CAS-PL-V014	Instrument Air Supply Outside Containment Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Refueling Shutdown Operability Test	18, 27, 30, 31
CAS-PL-V015	Instrument Air Supply Inside Containment Isolation	Check	Maintain Close Transfer Close	Active Containment Isolation Safety Seat Leakage	AC	Containment Isolation Leak Test Check Exercise/Refueling Shutdown	18, 27
CAS-PL-V204	Service Air Supply Outside Containment Isolation	Manual	Maintain Close	Containment Isolation Safety Seat Leakage	A	Containment Isolation Leak Test	27
CAS-PL-V205	Service Air Supply Inside Containment Isolation	Check	Maintain Close	Containment Isolation Safety Seat Leakage	AC	Containment Isolation Leak Test	27
CCS-PL-V200	CCS Containment Isolation Valve - Inlet Line ORC	Remote	Maintain Close Transfer Close	Active Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Cold Shutdown Operability Test	14, 27, 30, 31
CCS-PL-V201	CCS Containment Isolation Valve - Inlet Line IRC	Check	Maintain Close Transfer Close	Active Containment Isolation Safety Seat Leakage	AC	Containment Isolation Leak Test Check Exercise/Cold Shutdown	14, 27
CCS-PL-V207	CCS Containment Isolation Valve - Outlet Line IRC	Remote	Maintain Close Transfer Close	Active Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Cold Shutdown Operability Test	14, 27, 30, 31
CCS-PL-V208	CCS Containment Isolation Valve - Outlet Line ORC	Remote	Maintain Close Transfer Close	Active Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Cold Shutdown Operability Test	14, 27, 30, 31
CVS-PL-V001	RCS Purification Stop	Remote	Maintain Close Transfer Close	Active Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years RCS Isolation Leak Test/Refueling Exercise Full Stroke/Cold Shutdown Operability Test	6, 31, 32
CVS-PL-V002	RCS Purification Stop	Remote	Maintain Close Transfer Close	Active Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years RCS Isolation Leak Test/Refueling Exercise Full Stroke/Cold Shutdown Operability Test	6, 31, 32
CVS-PL-V003	RCS Purification Stop	Remote	Maintain Close Transfer Close	Active Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	6, 31

Table 3.9-16 (Sheet 2 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description[(1)]	Valve Type	Safety-Related Missions	Safety Functions[(2)]	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
CVS-PL-V040	Resin Flush IRC Isolation	Manual	Maintain Close	Containment Isolation Safety Seat Leakage	A	Containment Isolation Leak Test	27
CVS-PL-V041	Resin Flush ORC Isolation	Manual	Maintain Close	Containment Isolation Safety Seat Leakage	A	Containment Isolation Leak Test	27
CVS-PL-V042	Flush Line Containment Isolation Relief	Relief	Maintain Close Transfer Open Transfer Close	Active Containment Isolation Safety Seat Leakage	AC	Containment Isolation Leak Test Class 2/3 Relief Valve Tests/10 Years and 20% in 4 Years	27
CVS-PL-V045	Letdown Containment Isolation IRC	Remote	Maintain Close Transfer Close	Active-to-Failed RCS Pressure Boundary Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 31
CVS-PL-V047	Letdown Containment Isolation ORC	Remote	Maintain Close Transfer Close	Active-to-Failed RCS Pressure Boundary Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 31
CVS-PL-V080	RCS Purification Return Line Check Valve	Check	Maintain Close Transfer Close	Active Safety Seat Leakage	AC	Check Exercise/Cold Shutdown RCS Isolation Leak Test/Refueling	6, 32
CVS-PL-V081	RCS Purification Return Line Stop Valve	Check	Maintain Close Transfer Close	Active Safety Seat Leakage	AC	Check Exercise/Cold Shutdown RCS Isolation Leak Test/Refueling	6, 8, 32
CVS-PL-V082	RCS Purification Return Line Check Valve	Check	Maintain Close Transfer Close	Active Safety Seat Leakage	AC	Check Exercise/Cold Shutdown RCS Isolation Leak Test/Refueling	6, 32
CVS-PL-V084	Auxiliary Pressurizer Spray Line Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years RCS Isolation Leak Test/Refueling Exercise Full Stroke/Cold Shutdown Operability Test	22, 30, 31, 32
CVS-PL-V085	Auxiliary Pressurizer Spray Line	Check	Maintain Close Transfer Close	Active Safety Seat Leakage	AC	Check Exercise/Cold Shutdown RCS Isolation Leak Test/Refueling	22, 32
CVS-PL-V090	Makeup Line Containment Isolation	Remote	Maintain Close Transfer Close	Active RCS Pressure Boundary Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 31

Table 3.9-16 (Sheet 3 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description[1]	Valve Type	Safety-Related Missions	Safety Functions[2]	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
CVS-PL-V091	Makeup Line Containment Isolation	Remote	Maintain Close Transfer Close	Active RCS Pressure Boundary Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 31
CVS-PL-V092	Hydrogen Addition Containment Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed RCS Pressure Boundary Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operation Operability Test	27, 31
CVS-PL-V094	Hydrogen Addition IRC Isolation	Check	Maintain Close Transfer Close	Active RCS Pressure Boundary Containment Isolation Safety Seat Leakage Remote Position	AC	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Check Exercise/Quarterly Operation	27
CVS-PL-V100	Makeup Line Containment Isolation Relief	Check	Maintain Close Transfer Close Transfer Open	Active Containment Isolation Safety Seat Leakage	AC	Containment Isolation Leak Test/2 Years Check Exercise/Refueling Shutdown	23, 27
CVS-PL-V136A	Demineralized Water System Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31
CVS-PL-V136B	Demineralized Water System Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31
DWS-PL-V244	Demineralized Water Supply Containment Isolation - Outside	Manual	Maintain Close	Containment Isolation Safety Seat Leakage	A	Containment Isolation Leak Test	27
DWS-PL-V245	Demineralized Water Supply Containment Isolation - Inside	Check	Maintain Close	Containment Isolation Safety Seat Leakage	AC	Containment Isolation Leak Test	27
FPS-PL-V050	Fire Water Containment Supply Isolation	Manual	Maintain Close	Containment Isolation Safety Seat Leakage	A	Containment Isolation Leak Test	27
FPS-PL-V052	Fire Water Containment Supply Isolation - Inside	Check	Maintain Close	Containment Isolation Safety Seat Leakage	AC	Containment Isolation Leak Test	27
FHS-PL-V001	Fuel Transfer Tube Isolation Valve	Manual	Transfer Close Maintain Open	Active	B	Exercise Full Stroke/Refueling Shutdown	33

Table 3.9-16 (Sheet 4 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description(1)	Valve Type	Safety-Related Missions	Safety Functions(2)	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
MSS-PL-V001	Turbine Bypass Control Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	29, 31, 34
MSS-PL-V002	Turbine Bypass Control Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	29, 31, 34
MSS-PL-V003	Turbine Bypass Control Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	29, 31, 34
MSS-PL-V004	Turbine Bypass Control Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	29, 31, 34
MSS-PL-V005	Turbine Bypass Control Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	29, 31, 34
MSS-PL-V006	Turbine Bypass Control Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	29, 31, 34
MSS-PL-V016A	Moisture Separator Reheater Steam Supply Control Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Part Stroke/Operation Exercise Full Stroke/Cold Shutdown Operability Test	25, 31, 34
MSS-PL-V017A	Moisture Separator Reheater Steam Supply Bypass Control Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Part Stroke/Operation Exercise Full Stroke/Cold Shutdown Operability Test	25, 31, 34
MSS-PL-V016B	Moisture Separator Reheater Steam Supply Control Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Part Stroke/Operation Exercise Full Stroke/Cold Shutdown Operability Test	25, 31, 34
MSS-PL-V017B	Moisture Separator Reheater Steam Supply Bypass Control Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Part Stroke/Operation Exercise Full Stroke/Cold Shutdown Operability Test	25, 31, 34

Table 3.9-16 (Sheet 5 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description[(1)]	Valve Type	Safety-Related Missions	Safety Functions[(2)]	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
MTS-PL-V001A	Turbine Stop Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	31, 34, 35, 36
MTS-PL-V001B	Turbine Stop Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	31, 34, 35, 36
MTS-PL-V002A	Turbine Control Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Part Stroke/Operation Exercise Full Stroke/Cold Shutdown Operability Test	25, 31, 34, 36
MTS-PL-V002B	Turbine Control Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Part Stroke/Operation Exercise Full Stroke/Cold Shutdown Operability Test	25, 31, 34, 36
MTS-PL-V003A	Turbine Stop Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	31, 34, 35, 36
MTS-PL-V003B	Turbine Stop Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	31, 34, 35, 36
MTS-PL-V004A	Turbine Control Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Part Stroke/Operation Exercise Full Stroke/Cold Shutdown Operability Test	25, 31, 34, 36
MTS-PL-V004B	Turbine Control Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Part Stroke/Operation Exercise Full Stroke/Cold Shutdown Operability Test	25, 31, 34, 36
PCS-PL-V001A	PCCWST Isolation	Remote	Maintain Open Transfer Open	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31
PCS-PL-V001B	PCCWST Isolation	Remote	Maintain Open Transfer Open	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	
PCS-PL-V001C	PCCWST Isolation	Remote	Maintain Open Transfer Open	Active Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	

Table 3.9-16 (Sheet 6 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description(1)	Valve Type	Safety-Related Missions	Safety Functions(2)	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
PCS-PL-V002A	PCCWST Series Isolation	Remote	Maintain Open Transfer Open	Active Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	
PCS-PL-V002B	PCCWST Series Isolation	Remote	Maintain Open Transfer Open	Active Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	
PCS-PL-V002C	PCCWST Series Isolation	Remote	Maintain Open Transfer Open	Active Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	
PCS-PL-V005	PCCWST Supply to Fire Protection Service Isolation	Manual	Maintain Close Transfer Close	Active	B	Exercise Full Stroke/Quarterly	
PCS-PL-V009	Spent Fuel Pool Emergency Makeup Isolation	Manual	Maintain Close Transfer Open Maintain Open	Active	B	Exercise Full Stroke/Quarterly	
PCS-PL-V014	Post-72 Hour Water Source Isolation	Manual/ Check	Transfer Open	Active	B	Exercise Full Stroke/Quarterly Check Exercise/Refueling	
PCS-PL-V015	Water Bucket Makeup Line Drain Valve	Manual	Maintain Close Transfer Close	Active	B	Exercise Full Stroke/Quarterly	
PCS-PL-V020	Water Bucket Makeup Line Isolation Valve	Manual	Maintain Open Transfer Open	Active	B	Exercise Full Stroke/Quarterly	
PCS-PL-V023	PCS Recirculation Return Isolation	Manual	Maintain Close Transfer Close	Active	B	Exercise Full Stroke/Quarterly	13
PCS-PL-V039	PCCWST Long-Term Makeup Check Valve	Check	Maintain Open Transfer Open	Active	B	Check Exercise/Refueling	21
PCS-PL-V042	PCCWST Long-Term Makeup Isolation Drain Valve	Manual	Maintain Close Transfer Close	Active	B	Exercise Full Stroke/Quarterly	
PCS-PL-V044	PCCWST Long-Term Makeup Isolation Valve	Manual	Maintain Open Transfer Open	Active	B	Exercise Full Stroke/Quarterly	
PCS-PL-V045	Emergency Makeup to the Spent Fuel Pool Isolation Valve	Manual	Maintain Open Transfer Open	Active	B	Exercise Full Stroke/Quarterly	
PCS-PL-V046	PCCWST Recirculation Return Isolation Valve	Manual	Maintain Close Transfer Close	Active	B	Exercise Full Stroke/Quarterly	
PCS-PL-V049	Emergency Makeup to the Spent Fuel Pool Drain Isolation Valve	Manual	Maintain Close Transfer Close	Active	B	Exercise Full Stroke/Quarterly	
PCS-PL-V050	Spent Fuel Pool Long-Term Makeup Isolation Valve	Manual	Maintain Open Transfer Open	Active	B	Exercise Full Stroke/Quarterly	

Table 3.9-16 (Sheet 7 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description[(1)]	Valve Type	Safety-Related Missions	Safety Functions[(2)]	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
PCS-PL-V051	Spent Fuel Pool Emergency Makeup Lower Isolation Valve	Manual	Maintain Close Transfer Close	Active	B	Exercise Full Stroke/Quarterly	
PSS-PL-V008	Containment Air Sample Containment Isolation IRC	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 30, 31
PSS-PL-V010A	Liquid Sample Line Containment Isolation IRC	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 31
PSS-PL-V010B	Liquid Sample Line Containment Isolation IRC	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 31
PSS-PL-V011	Liquid Sample Line Containment Isolation ORC	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 31
PSS-PL-V023	Sample Return Line Containment Isolation ORC	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 31
PSS-PL-V024	Sample Return Containment Isolation Check IRC	Check	Maintain Close Transfer Close	Active Containment Isolation Safety Seat Leakage	AC	Containment Isolation Leak Test Check Exercise/Refueling Shutdown	19, 27
PSS-PL-V046	Air Sample Line Containment Isolation ORC	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 30, 31
PXS-PL-V002A	Core Makeup Tank A Cold Leg Inlet Isolation	Remote	Maintain Open	Remote Position	B	Remote Position Indication, Exercise/2 Years	
PXS-PL-V002B	Core Makeup Tank B Cold Leg Inlet Isolation	Remote	Maintain Open	Remote Position	B	Remote Position Indication, Exercise/2 Years	
PXS-PL-V014A	Core Makeup Tank A Discharge Isolation	Remote	Maintain Open Transfer Open	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31
PXS-PL-V014B	Core Makeup Tank B Discharge Isolation	Remote	Maintain Open Transfer Open	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31

Table 3.9-16 (Sheet 8 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description[1]	Valve Type	Safety-Related Missions	Safety Functions[2]	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
PXS-PL-V015A	Core Makeup Tank A Discharge Isolation	Remote	Maintain Open Transfer Open	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31
PXS-PL-V015B	Core Makeup Tank B Discharge Isolation	Remote	Maintain Open Transfer Open	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31
PXS-PL-V016A	Core Makeup Tank A Discharge Check	Check	Maintain Open Transfer Open Transfer Close	Active Remote Position	BC	Remote Position Indication, Exercise/2 Years Check Exercise/Refueling Shutdown	10
PXS-PL-V016B	Core Makeup Tank B Discharge Check	Check	Maintain Open Transfer Open Transfer Close	Active Remote Position	BC	Remote Position Indication, Exercise/2 Years Check Exercise/Refueling Shutdown	10
PXS-PL-V017A	Core Makeup Tank A Discharge Check	Check	Maintain Open Transfer Open Transfer Close	Active Remote Position	BC	Remote Position Indication, Exercise/2 Years Check Exercise/Refueling Shutdown	10
PXS-PL-V017B	Core Makeup Tank B Discharge Check	Check	Maintain Open Transfer Open Transfer Close	Active Remote Position	BC	Remote Position Indication, Exercise/2 Years Check Exercise/Refueling Shutdown	10
PXS-PL-V022A	Accumulator A Pressure Relief	Relief	Maintain Close Transfer Open Transfer Close	Active	BC	Class 2/3 Relief Valve Tests/10 Years and 20% in 4 Years	
PXS-PL-V022B	Accumulator B Pressure Relief	Relief	Maintain Close Transfer Open Transfer Close	Active	BC	Class 2/3 Relief Valve Tests/10 Years and 20% in 4 Years	
PXS-PL-V027A	Accumulator A Discharge Isolation	Remote	Maintain Open	Remote Position	B	Remote Position Indication, Exercise/2 Years	
PXS-PL-V027B	Accumulator B Discharge Isolation	Remote	Maintain Open	Remote Position	B	Remote Position Indication, Exercise/2 Years	
PXS-PL-V028A	Accumulator A Discharge Check	Check	Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position Safety Seat Leakage	AC	Remote Position Indication, Exercise/2 Years Check Exercise/Refueling Shutdown Pressure Isolation Leak Test/Refueling Shutdown	9
PXS-PL-V028B	Accumulator B Discharge Check	Check	Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position Safety Seat Leakage	AC	Remote Position Indication, Exercise/2 Years Check Exercise/Refueling Shutdown Pressure Isolation Leak Test/Refueling Shutdown	9

Table 3.9-16 (Sheet 9 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description(1)	Valve Type	Safety-Related Missions	Safety Functions(2)	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
PXS-PL-V029A	Accumulator A Discharge Check	Check	Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position Safety Seat Leakage	AC	Remote Position Indication, Exercise/2 Years Check Exercise/Refueling Shutdown Pressure Isolation Leak Test/Refueling Shutdown	9
PXS-PL-V029B	Accumulator B Discharge Check	Check	Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position Safety Seat Leakage	AC	Remote Position Indication, Exercise/2 Years Check Exercise/Refueling Shutdown Pressure Isolation Leak Test/Refueling Shutdown	9
PXS-PL-V042	Nitrogen Supply Containment Isolation ORC	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 30, 31
PXS-PL-V043	Nitrogen Supply Containment Isolation IRC	Check	Maintain Close Transfer Close	Active Containment Isolation Safety Seat Leakage Remote Position	AC	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Check Exercise/Quarterly	27
PXS-PL-V101	PRHR HX Inlet Isolation	Remote	Maintain Open	Remote Position	B	Remote Position Indication, Exercise/2 Years	
PXS-PL-V108A	PRHR HX Control	Remote	Maintain Open Transfer Open	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31
PXS-PL-V108B	PRHR HX Control	Remote	Maintain Open Transfer Open	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31
PXS-PL-V117A	Containment Recirculation A Isolation	Remote	Maintain Open Maintain Close Transfer Open	Active Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31
PXS-PL-V117B	Containment Recirculation B Isolation	Remote	Maintain Open Maintain Close Transfer Open	Active Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31
PXS-PL-V118A	Containment Recirculation A Isolation	Squib	Maintain Open Maintain Close Transfer Open	Active Remote Position	D	Remote Position Indication, Alternate/2 Years Charge Test Fire/20% in 2 Years	5
PXS-PL-V118B	Containment Recirculation B Isolation	Squib	Maintain Open Maintain Close Transfer Open	Active Remote Position	D	Remote Position Indication, Alternate/2 Years Charge Test Fire/20% in 2 Years	5
PXS-PL-V119A	Containment Recirculation A Check	Check	Maintain Open Maintain Close Transfer Open	Active Remote Position	BC	Remote Position Indication, Exercise/2 Years Check-Initial Open Differential Pressure/2 Years Check Exercise/Refueling Shutdown	11

Table 3.9-16 (Sheet 10 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description[1]	Valve Type	Safety-Related Missions	Safety Functions[2]	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
PXS-PL-V119B	Containment Recirculation B Check	Check	Maintain Open Maintain Close Transfer Open	Active Remote Position	BC	Remote Position Indication, Exercise/2 Years Check-Initial Open Differential Pressure/2 Years Check Exercise/Refueling Shutdown	11
PXS-PL-V120A	Containment Recirculation A Isolation	Squib	Maintain Open Maintain Close Transfer Open	Active Remote Position	D	Remote Position Indication, Alternate/2 Years Charge Test Fire/20% in 2 Years	5
PXS-PL-V120B	Containment Recirculation B Isolation	Squib	Maintain Open Maintain Close Transfer Open	Active Remote Position	D	Remote Position Indication, Alternate/2 Years Charge Test Fire/20% in 2 Years	5
PXS-PL-V121A	IRWST Line A Isolation	Remote	Maintain Open	Remote Position	B	Remote Position Indication, Exercise/2 Years	
PXS-PL-V121B	IRWST Line B Isolation	Remote	Maintain Open	Remote Position	B	Remote Position Indication, Exercise/2 Years	
PXS-PL-V122A	IRWST Injection A Check	Check	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	BC	Remote Position Indication, Exercise/2 Years Check-Initial Open Differential Pressure/2 Years Check Exercise/Refueling Shutdown	12
PXS-PL-V122B	IRWST Injection B Check	Check	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	BC	Remote Position Indication, Exercise/2 Years Check-Initial Open Differential Pressure/2 Years Check Exercise/Refueling Shutdown	12
PXS-PL-V123A	IRWST Injection A Isolation	Squib	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	D	Remote Position Indication, Alternate/2 Years Charge Test Fire/20% in 2 Years	5
PXS-PL-V123B	IRWST Injection B Isolation	Squib	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	D	Remote Position Indication, Alternate/2 Years Charge Test Fire/20% in 2 Years	5
PXS-PL-V124A	IRWST Injection A Check	Check	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	BC	Remote Position Indication, Exercise/2 Years Check-Initial Open Differential Pressure/2 Years Check Exercise/Refueling Shutdown	12
PXS-PL-V124B	IRWST Injection B Check	Check	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	BC	Remote Position Indication, Exercise/2 Years Check-Initial Open Differential Pressure/2 Years Check Exercise/Refueling Shutdown	12
PXS-PL-V125A	IRWST Injection A Isolation	Squib	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	D	Remote Position Indication, Alternate/2 Years Charge Test Fire/20% in 2 Years	5
PXS-PL-V125B	IRWST Injection B Isolation	Squib	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	D	Remote Position Indication, Alternate/2 Years Charge Test Fire/20% in 2 Years	5
PXS-PL-130A	IRWST Gutter Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31

Table 3.9-16 (Sheet 11 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description[1]	Valve Type	Safety-Related Missions	Safety Functions[2]	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
PXS-PL-130B	IRWST Gutter Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31
PXS-PL-V208A	RNS Suction Leak Test	Manual	Maintain Close	Containment Isolation Safety Seat Leakage	A	Containment Isolation Leak Test/2 Years	
RCS-PL-V001A	First Stage Automatic Depressurization System	Remote	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	3, 31
RCS-PL-V001B	First Stage Automatic Depressurization System	Remote	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	3, 31
RCS-PL-V002A	Second Stage Automatic Depressurization System	Remote	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	3, 31
RCS-PL-V002B	Second Stage Automatic Depressurization System	Remote	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	3, 31
RCS-PL-V003A	Third Stage Automatic Depressurization System	Remote	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	3, 31
RCS-PL-V003B	Third Stage Automatic Depressurization System	Remote	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	3, 31
RCS-PL-V004A	Fourth Stage Automatic Depressurization System	Squib	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	D	Remote Position Indication, Alternate/2 Years Charge Test Fire/20% in 2 Years	5
RCS-PL-V004B	Fourth Stage Automatic Depressurization System	Squib	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	D	Remote Position Indication, Alternate/2 Years Charge Test Fire/20% in 2 Years	5
RCS-PL-V004C	Fourth Stage Automatic Depressurization System	Squib	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	D	Remote Position Indication, Alternate/2 Years Charge Test Fire/20% in 2 Years	5
RCS-PL-V004D	Fourth Stage Automatic Depressurization System	Squib	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	D	Remote Position Indication, Alternate/2 Years Charge Test Fire/20% in 2 Years	5
RCS-PL-V005A	Pressurizer Safety Valve	Relief	Maintain Close Transfer Open Transfer Close	Active RCS Pressure Boundary Remote Position	BC	Remote Position Indication, Alternate/2 Years Class 1 Relief Valve Tests/5 Years and 20% in 2 Years	7

Table 3.9-16 (Sheet 12 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description(1)	Valve Type	Safety-Related Missions	Safety Functions(2)	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
RCS-PL-V005B	Pressurizer Safety Valve	Relief	Maintain Close Transfer Open Transfer Close	Active RCS Pressure Boundary Remote Position	BC	Remote Position Indication, Alternate/2 Years Class 1 Relief Valve Tests/5 Years and 20% in 2 Years	7
RCS-PL-V010A	Automatic Depressurization System Discharge Header A Vacuum Relief	Relief	Transfer Open	Active	BC	Class 2/3 Relief Valve Tests/10 Years and 20% in 4 Years	
RCS-PL-V010B	Automatic Depressurization System Discharge Header B Vacuum Relief	Relief	Transfer Open	Active	BC	Class 2/3 Relief Valve Tests/10 Years and 20% in 4 Years	
RCS-PL-V011A	First Stage Automatic Depressurization System Isolation	Remote	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	3, 31
RCS-PL-V011B	First Stage Automatic Depressurization System Isolation	Remote	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	3, 31
RCS-PL-V012A	Second Stage Automatic Depressurization System Isolation	Remote	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	3, 31
RCS-PL-V012B	Second Stage Automatic Depressurization System Isolation	Remote	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	3, 31
RCS-PL-V013A	Third Stage Automatic Depressurization System Isolation	Remote	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	3, 31
RCS-PL-V013B	Third Stage Automatic Depressurization System Isolation	Remote	Maintain Open Maintain Close Transfer Open	Active RCS Pressure Boundary Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	3, 31
RCS-PL-V014A	Fourth Stage Automatic Depressurization System Isolation	Remote	Maintain Open	Remote Position	B	Remote Position Indication, Exercise/2 Years	
RCS-PL-V014B	Fourth Stage Automatic Depressurization System Isolation	Remote	Maintain Open	Remote Position	B	Remote Position Indication, Exercise/2 Years	
RCS-PL-V014C	Fourth Stage Automatic Depressurization System Isolation	Remote	Maintain Open	Remote Position	B	Remote Position Indication, Exercise/2 Years	
RCS-PL-V014D	Fourth Stage Automatic Depressurization System Isolation	Remote	Maintain Open	Remote Position	B	Remote Position Indication, Exercise/2 Years	
RCS-PL-V150A	Reactor Vessel Head Vent	Remote	Maintain Open Maintain Close Transfer Open	Active-to-Failed RCS Pressure Boundary Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	4, 31
RCS-PL-V150B	Reactor Vessel Head Vent	Remote	Maintain Open Maintain Close Transfer Open	Active-to-Failed RCS Pressure Boundary Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	4, 31
RCS-PL-V150C	Reactor Vessel Head Vent	Remote	Maintain Open Maintain Close Transfer Open	Active-to-Failed RCS Pressure Boundary Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	4, 31

Table 3.9-16 (Sheet 13 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description[1]	Valve Type	Safety-Related Missions	Safety Functions[2]	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
RCS-PL-V150D	Reactor Vessel Head Vent	Remote	Maintain Open Maintain Close Transfer Open	Active-to-Failed RCS Pressure Boundary Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Operability Test	4, 31
RCS-K03	Safety Valve Discharge Chamber Rupture Disk	Relief	Transfer Open	Active	BC	Inspect and Replace/5 Years	
RCS-K04	Safety Valve Discharge Chamber Rupture Disk	Relief	Transfer Open	Active	BC	Inspect and Replace/5 Years	
RNS-PL-V001A	RNS Hot Leg Suction Isolation - Inner	Remote	Maintain Close Transfer Close	Active RCS Pressure Boundary Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Pressure Isolation Leak Test/Refueling Shutdown Operability Test	15, 30, 31
RNS-PL-V001B	RNS Hot Leg Suction Isolation - Inner	Remote	Maintain Close Transfer Close	Active RCS Pressure Boundary Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Pressure Isolation Leak Test/Refueling Shutdown Operability Test	15, 30, 31
RNS-PL-V002A	RNS Hot Leg Suction and Containment Isolation - Outer	Remote	Maintain Close Transfer Close	Active RCS Pressure Boundary Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Pressure Isolation Leak Test/Refueling Shutdown Operability Test	15, 16, 30, 31
RNS-PL-V002B	RNS Hot Leg Suction and Containment Isolation - Outer	Remote	Maintain Close Transfer Close	Active RCS Pressure Boundary Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Cold Shutdown Pressure Isolation Leak Test/Refueling Shutdown Operability Test	15, 16, 30, 31
RNS-PL-V003A	RCS Pressure Boundary Valve Thermal Relief	Check	Maintain Close Transfer Open Transfer Close	Active RCS Pressure Boundary	BC	Check Exercise/Refueling Shutdown	23
RNS-PL-V003B	RCS Pressure Boundary Valve Thermal Relief	Check	Maintain Close Transfer Open Transfer Close	Active RCS Pressure Boundary	BC	Check Exercise/Refueling Shutdown	23
RNS-PL-V011	RNS Discharge Containment Isolation Valve - ORC	Remote	Maintain Close Transfer Close	Active Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 30, 31
RNS-PL-V013	RNS Discharge Containment Isolation - IRC	Check	Maintain Close Transfer Open Transfer Close	Active Containment Isolation Safety Seat Leakage	AC	Containment Isolation Leak Test Check Exercise/Quarterly	27
RNS-PL-V015A	RNS Discharge RCS Pressure Boundary	Check	Maintain Close Transfer Close	Active RCS Pressure Boundary Safety Seat Leakage	AC	Check Exercise/Refueling Shutdown Pressure Isolation Leak Test/Refueling Shutdown	24

Table 3.9-16 (Sheet 14 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description[(1)]	Valve Type	Safety-Related Missions	Safety Functions[(2)]	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
RNS-PL-V015B	RNS Discharge RCS Pressure Boundary	Check	Maintain Close Transfer Close	Active RCS Pressure Boundary Safety Seat Leakage	AC	Check Exercise/Refueling Shutdown Pressure Isolation Leak Test/Refueling Shutdown	24
RNS-PL-V017A	RNS Discharge RCS Pressure Boundary	Check	Maintain Close Transfer Open Transfer Close	Active RCS Pressure Boundary Safety Seat Leakage	AC	Check Exercise/Refueling Shutdown Pressure Isolation Leak Test/Refueling Shutdown	24
RNS-PL-V017B	RNS Discharge RCS Pressure Boundary	Check	Maintain Close Transfer Open Transfer Close	Active RCS Pressure Boundary Safety Seat Leakage	AC	Check Exercise/Refueling Shutdown Pressure Isolation Leak Test/Refueling Shutdown	24
RNS-PL-V021	RNS Hot Leg Suction Pressure Relief	Relief	Maintain Close Transfer Open Transfer Close	Active Containment Isolation Safety Seat Leakage	AC	Containment Isolation Leak Test/2 Years Class 2/3 Relief Valve Tests/10 Years and 20% in 4 Years	17, 27
RNS-PL-V022	RNS Suction Header Containment Isolation - ORC	Remote	Maintain Close Transfer Close	Active Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 30, 31
RNS-PL-V023	RNS Suction from IRWST - Containment Isolation	Remote	Maintain Close Transfer Close	Active Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	17, 27, 30, 31
RNS-PL-V045	RNS Pump Discharge Relief	Relief	Maintain Close Transfer Open Transfer Close	Active	BC	Class 2/3 Relief Valve Tests/10 Years and 20% in 4 Years	
RNS-PL-V046	RNS Heat Exchanger A Channel Head Drain Isolation	Manual	Maintain Open Transfer Open	Active	B	Exercise Full Stroke/Quarterly	
RNS-PL-V061	RNS Return from CVS - Containment Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 31
SFS-PL-V034	SFS Suction Line Containment Isolation	Remote	Maintain Close Transfer Close	Active Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 30, 31
SFS-PL-V035	SFS Suction Line Containment Isolation	Remote	Maintain Close Transfer Close	Active Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 30, 31

Table 3.9-16 (Sheet 15 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description[(1)]	Valve Type	Safety-Related Missions	Safety Functions[(2)]	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
SFS-PL-V037	SFS Discharge Line Containment Isolation	Check	Maintain Close Transfer Close Transfer Open	Active Containment Isolation Safety Seat Leakage	AC	Containment Isolation Leak Test Check Exercise/Quarterly	27
SFS-PL-V038	SFS Discharge Line Containment Isolation	Remote	Maintain Close Transfer Close	Active Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 30, 31
SFS-PL-V071	Refueling Cavity to Steam Generator Compartment	Check	Transfer Open Transfer Close Maintain Close	Active	BC	Check Exercise/Refueling Shutdown	26
SFS-PL-V072	Refueling Cavity to Steam Generator Compartment	Check	Transfer Open Transfer Close Maintain Close	Active	BC	Check Exercise/Refueling Shutdown	26
SGS-PL-V027A	Power-Operated Relief Valve Block Valve Steam Generator 01	Remote	Maintain Close Transfer Close	Active Containment Isolation Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
SGS-PL-V027B	Power-Operated Relief Valve Block Valve Steam Generator 02	Remote	Maintain Close Transfer Close	Active Containment Isolation Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
SGS-PL-V030A	Main Steam Safety Valve Steam Generator 01	Relief	Maintain Close Transfer Open Transfer Close	Active Containment Isolation Remote Position	BC	Remote Position Indication, Alternate/2 Years Class 2/3 Relief Valve Tests/5 Years and 20% in 2 Years	7
SGS-PL-V030B	Main Steam Safety Valve Steam Generator 02	Relief	Maintain Close Transfer Open Transfer Close	Active Containment Isolation Remote Position	BC	Remote Position Indication, Alternate/2 Years Class 2/3 Relief Valve Tests/5 Years and 20% in 2 Years	7
SGS-PL-V031A	Main Steam Safety Valve Steam Generator 01	Relief	Maintain Close Transfer Open Transfer Close	Active Containment Isolation Remote Position	BC	Remote Position Indication, Alternate/2 Years Class 2/3 Relief Valve Tests/5 Years and 20% in 2 Years	7
SGS-PL-V031B	Main Steam Safety Valve Steam Generator 02	Relief	Maintain Close Transfer Open Transfer Close	Active Containment Isolation Remote Position	BC	Remote Position Indication, Alternate/2 Years Class 2/3 Relief Valve Tests/5 Years and 20% in 2 Years	7
SGS-PL-V032A	Main Steam Safety Valve Steam Generator 01	Relief	Maintain Close Transfer Open Transfer Close	Active Containment Isolation Remote Position	BC	Remote Position Indication, Alternate/2 Years Class 2/3 Relief Valve Tests/5 Years and 20% in 2 Years	7

Table 3.9-16 (Sheet 16 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description(1)	Valve Type	Safety-Related Missions	Safety Functions(2)	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
SGS-PL-V032B	Main Steam Safety Valve Steam Generator 02	Relief	Maintain Close Transfer Open Transfer Close	Active Containment Isolation Remote Position	BC	Remote Position Indication, Alternate/2 Years Class 2/3 Relief Valve Tests/5 Years and 20% in 2 Years	7
SGS-PL-V033A	Main Steam Safety Valve Steam Generator 01	Relief	Maintain Close Transfer Open Transfer Close	Active Containment Isolation Remote Position	BC	Remote Position Indication, Alternate/2 Years Class 2/3 Relief Valve Tests/5 Years and 20% in 2 Years	7
SGS-PL-V033B	Main Steam Safety Valve Steam Generator 02	Relief	Maintain Close Transfer Open Transfer Close	Active Containment Isolation Remote Position	BC	Remote Position Indication, Alternate/2 Years Class 2/3 Relief Valve Tests/5 Years and 20% in 2 Years	7
SGS-PL-V034A	Main Steam Safety Valve Steam Generator 01	Relief	Maintain Close Transfer Open Transfer Close	Active Containment Isolation Remote Position	BC	Remote Position Indication, Alternate/2 Years Class 2/3 Relief Valve Tests/5 Years and 20% in 2 Years	7
SGS-PL-V034B	Main Steam Safety Valve Steam Generator 02	Relief	Maintain Close Transfer Open Transfer Close	Active Containment Isolation Remote Position	BC	Remote Position Indication, Alternate/2 Years Class 2/3 Relief Valve Tests/5 Years and 20% in 2 Years	7
SGS-PL-V035A	Main Steam Safety Valve Steam Generator 01	Relief	Maintain Close Transfer Open Transfer Close	Active Containment Isolation Remote Position	BC	Remote Position Indication, Alternate/2 Years Class 2/3 Relief Valve Tests/5 Years and 20% in 2 Years	7
SGS-PL-V035B	Main Steam Safety Valve Steam Generator 02	Relief	Maintain Close Transfer Open Transfer Close	Active Containment Isolation Remote Position	BC	Remote Position Indication, Alternate/2 Years Class 2/3 Relief Valve Tests/5 Years and 20% in 2 Years	7
SGS-PL-V036A	Steam Line Condensate Drain Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
SGS-PL-V036B	Steam Line Condensate Drain Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
SGS-PL-V040A	Main Steam Line Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Part Stroke/Quarterly Exercise Full Stroke/Cold Shutdown Operability Test	20, 31
SGS-PL-V040B	Main Steam Line Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Part Stroke/Quarterly Exercise Full Stroke/Cold Shutdown Operability Test	20, 31

Table 3.9-16 (Sheet 17 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description[1]	Valve Type	Safety-Related Missions	Safety Functions[2]	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
SGS-PL-V057A	Main Feedwater Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Part Stroke/Quarterly Exercise Full Stroke/Cold Shutdown Operability Test	20, 31
SGS-PL-V057B	Main Feedwater Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Part Stroke/Quarterly Exercise Full Stroke/Cold Shutdown Operability Test	20, 31
SGS-PL-V067A	Startup Feedwater Isolation	Remote	Maintain Close Transfer Close	Active Containment Isolation Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
SGS-PL-V067B	Startup Feedwater Isolation	Remote	Maintain Close Transfer Close	Active Containment Isolation Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
SGS-PL-V074A	Steam Generator Blowdown Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
SGS-PL-V074B	Steam Generator Blowdown Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
SGS-PL-V075A	Steam Generator Series Blowdown Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
SGS-PL-V075B	Steam Generator Series Blowdown Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
SGS-PL-V086A	Steam Line Condensate Drain Control	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operation Operability Test	31
SGS-PL-V086B	Steam Line Condensate Drain Control	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
SGS-PL-V233A	Power-Operated Relief Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
SGS-PL-V233B	Power-Operated Relief Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31

Table 3.9-16 (Sheet 18 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description[1]	Valve Type	Safety-Related Missions	Safety Functions[2]	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
SGS-PL-V240A	Main Steam Isolation Valve Bypass Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
SGS-PL-V240B	Main Steam Isolation Valve Bypass Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
SGS-PL-V250A	Main Feedwater Control	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Part Stroke/Quarterly Operation Exercise Full Stroke/Cold Shutdown Operability Test	25, 31
SGS-PL-V250B	Main Feedwater Control	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Part Stroke/Quarterly Operation Exercise Full Stroke/Cold Shutdown Operability Test	25, 31
SGS-PL-V255A	Startup Feedwater Control	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
SGS-PL-V255B	Startup Feedwater Control	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
VBS-PL-V186	MCR Supply Air Isolation Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31
VBS-PL-V187	MCR Supply Air Isolation Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31
VBS-PL-V188	MCR Return Air Isolation Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31
VBS-PL-V189	MCR Return Air Isolation Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31
VBS-PL-V190	MCR Exhaust Air Isolation Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31

Table 3.9-16 (Sheet 19 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description(1)	Valve Type	Safety-Related Missions	Safety Functions(2)	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
VBS-PL-V191	MCR Exhaust Air Isolation Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Remote Position	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	30, 31
VES-PL-V001	Air Delivery Isolation Valve	Manual	Maintain Close Transfer Open Maintain Open	Active	B	Exercise Full Stroke/Quarterly	
VES-PL-V002A	Pressure Regulating Valve A	Press. Reg.	Throttle Flow	Active	B	Exercise Full Stroke/Quarterly Operability Test	31
VES-PL-V002B	Pressure Regulating Valve B	Press. Reg.	Throttle Flow	Active	B	Exercise Full Stroke/Quarterly Operability Test	31
VES-PL-V005A	Air Delivery Isolation Valve A	Remote	Maintain Open Transfer Open	Active-to-Failed	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
VES-PL-V005B	Air Delivery Isolation Valve B	Remote	Maintain Open Transfer Open	Active-to-Failed	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
VES-PL-V022A	Pressure Relief Isolation Valve A	Remote	Maintain Open Transfer Open	Active-to-Failed	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
VES-PL-V022B	Pressure Relief Isolation Valve B	Remote	Maintain Open Transfer Open	Active-to-Failed	B	Remote Position Indication, Exercise/2 Years Exercise Full Stroke/Quarterly Operability Test	31
VES-PL-V040A	Air Tank Safety Relief Valve A	Relief	Maintain Close Transfer Open	Active	BC	Class 2/3 Relief Valve Tests/10 Years and 20% in 4 Years	
VES-PL-V040B	Air Tank Safety Relief Valve B	Relief	Maintain Close Transfer Open	Active	BC	Class 2/3 Relief Valve Tests/10 Years and 20% in 4 Years	
VES-PL-V041A	Air Tank Safety Relief Valve A	Relief	Maintain Close Transfer Open	Active	BC	Class 2/3 Relief Valve Tests/10 Years and 20% in 4 Years	
VES-PL-V041B	Air Tank Safety Relief Valve B	Relief	Maintain Close Transfer Open	Active	BC	Class 2/3 Relief Valve Tests/10 Years and 20% in 4 Years	
VES-PL-V044	Main Air Flowpath Isolation Valve	Manual	Maintain Close Transfer Open	Active	B	Exercise Full Stroke/Quarterly	

Table 3.9-16 (Sheet 20 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description(1)	Valve Type	Safety-Related Missions	Safety Functions(2)	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
VFS-PL-V003	Containment Purge Inlet Containment Isolation Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 30, 31
VFS-PL-V004	Containment Purge Inlet Containment Isolation Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 30, 31
VFS-PL-V009	Containment Purge Discharge Containment Isolation Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 30, 31
VFS-PL-V010	Containment Purge Discharge Containment Isolation Valve	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 30, 31
VWS-PL-V058	Fan Coolers Supply Containment Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 28, 30, 31
VWS-PL-V062	Fan Coolers Supply Containment Isolation	Check	Maintain Close Transfer Close	Active Containment Isolation Safety Seat Leakage	AC	Containment Isolation Leak Test Check Exercise/Quarterly	27, 28
VWS-PL-V082	Fan Coolers Return Containment Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 28, 30, 31
VWS-PL-V086	Fan Coolers Return Containment Isolation	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operability Test	27, 28, 30, 31
WLS-PL-V055	Sump Discharge Containment Isolation IRC	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operation Operability Test	27, 30, 31

Table 3.9-16 (Sheet 21 of 21)

VALVE INSERVICE TEST REQUIREMENTS

Valve Tag Number	Description(1)	Valve Type	Safety-Related Missions	Safety Functions(2)	ASME IST Category	Inservice Testing Type and Frequency	IST Notes
WLS-PL-V057	Sump Discharge Containment Isolation ORC	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operation Operability Test	27, 30, 31
WLS-PL-V067	Reactor Coolant Drain Tank Gas Outlet Containment Isolation IRC	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operation Operability Test	27, 30, 31
WLS-PL-V068	Reactor Coolant Drain Tank Gas Outlet Containment Isolation ORC	Remote	Maintain Close Transfer Close	Active-to-Failed Containment Isolation Safety Seat Leakage Remote Position	A	Remote Position Indication, Exercise/2 Years Containment Isolation Leak Test Exercise Full Stroke/Quarterly Operation Operability Test	27, 30, 31
WLS-PL-V071A	CVS Compartment to Sump	Check	Maintain Close Transfer Close	Active	BC	Check Exercise/Refueling Shutdown	26
WLS-PL-V071B	PXS A Compartment to Sump	Check	Maintain Close Transfer Close	Active	BC	Check Exercise/Refueling Shutdown	26
WLS-PL-V071C	PXS B Compartment to Sump	Check	Maintain Close Transfer Close	Active	BC	Check Exercise/Refueling Shutdown	26
WLS-PL-V072A	CVS Compartment to Sump	Check	Maintain Close Transfer Close	Active	BC	Check Exercise/Refueling Shutdown	26
WLS-PL-V072B	PXS A Compartment to Sump	Check	Maintain Close Transfer Close	Active	BC	Check Exercise/Refueling Shutdown	26
WLS-PL-V072C	PXS B Compartment to Sump	Check	Maintain Close Transfer Close	Active	BC	Check Exercise/Refueling Shutdown	26

Notes:

1. Acronyms:

ADS	automatic depressurization system
CAS	compressed and instrument air system
CCS	component cooling water system
CVS	chemical and volume control system
DWS	demineralized water transfer and storage system
FPS	fire protection system
IRC	inside reactor containment
IRWST	in-containment refueling water storage tank
MSS	main steam system
MTS	main turbine system
ORC	outside reactor containment
PCCWST	passive containment cooling water storage tank
PCS	passive containment cooling system
PSS	primary sampling system
PXS	passive core cooling system
RCS	reactor coolant system
RNS	normal residual heat removal system
SFS	spent fuel pool cooling system
SGS	steam generator system
VBS	nuclear island nonradioactive ventilation system
VES	main control room emergency habitability system
VFS	containment air filtration system
VWS	central chilled water system
WLS	liquid radwaste system

2. Valves listed as having an active or an active-to-failed safety-related function provide the safety-related valve transfer capabilities identified in the safety-related mission column. Valves having an active-to-failed function will transfer to the position identified in the safety-related mission column on loss of motive power.

3. This note applies to the ADS stage 1/2/3 valves (RCS-V001A/B, V002A/B, V003A/B, V011A/B, V012A/B, V013A/B). These valves are normally closed to maintain the RCS pressure boundary. These valves have a safety-related function to open following LOCAs to allow safety injection from lower pressure water supplies (accumulators and IRWST). These valves also have beyond design basis functions to depressurize the RCS. These valves have the same design pressure as the RCS and are AP1000 equipment class A. Downstream of the second valve is a lower design pressure and is equipment class C. The discharge of these valves is open to the containment through the IRWST.

   Both ADS valves in each line are normally closed during normal reactor operation in accordance with 10 CFR 50.2 and ANS/ANSI 51.1. If one of these valves is opened, for example for testing, the RCS pressure boundary is not maintained in accordance with the criteria contained in these two documents. In addition, the ADS valve configuration is similar to the normal residual heat removal system suction valve configuration. Even though the RNS suction valve configuration includes a third valve in the high pressure portion of the line, and the first two RNS valves have safety related functions to transfer closed, they are not stroke tested during normal reactor operation to avoid a plant configuration where the mispositioning of one valve would cause a LOCA. Note 15 describes the justification for testing the RNS valves during cold shutdown.

   These ADS valves are tested during cold shutdowns when the RCS pressure is reduced to atmospheric pressure so that mispositioning of a single valve during this IST will not cause a LOCA. Testing these valves every cold shutdown is consistent with the AP1000 PRA which assumes more than 2 cold or refueling shutdowns per year.

4. This note applies to the reactor vessel head vent solenoid valves (RCS-V150A/B/C/D). Exercise testing of these valves at power represents a risk of loss of reactor coolant and depressurization of the RCS if the proper test sequence is not followed. Such testing may also result in the valves developing through seal leaks. Exercise testing of these valves will be performed at cold shutdown.

5. This note applies to squib valves in the RCS and the PXS. The squib valve charge is removed and test fired outside of valve. Squib valves are not exercised for inservice testing. Their position indication sensors will be tested by local inspection.

6. This note applies to the CVS isolation valves (CVS-V001, V002, V003, V080, V081, V082). Closing these valves at power will result in an undesirable temperature transient on the RCS due to the interruption of purification flow. Therefore, quarterly exercise testing will not be performed. Exercise testing will be performed at cold shutdown.

7. This note applies to the pressurizer safety valves (RCS-V005A/B) and to the main steam safety valves (SGS-V030A/B, V031A/B, V032A/B, V033A/B, V034A/B and V035A/B). Since these valves are not exercised for inservice testing, their position indication sensors are tested by local inspection without valve exercise.

8. This note applies to CVS valve (CVS-V081). The safety functions are satisfied by the check valve function of the valve.

9. This note applies to the PXS accumulator check valves (PXS-V028A/B, V029A/B). To exercise these valves, flow must be provided through these valves to the RCS. These valves are not exercised during power operations because the accumulators cannot provide flow to the RCS since they are at a lower pressure. In addition, providing flow to the RCS during power operation would cause undesirable thermal transients on the RCS. During cold shutdowns, a full flow stroke test is impractical because of the potential of adding significant water to the RCS, and lifting the RNS relief valve. There is also a risk of injecting nitrogen into the RCS. A partial stroke test is practical during longer cold shutdowns (≥48 hours in Mode 5). In this test, flow is provided from test connections, through the check valves and into the RCS. Sufficient flow in not available to provide a detectable obturator movement. Full stroke exercise testing of these valves is conducted during refueling shutdowns.

10. This note applies to the PXS CMT check valves (PXS-V016A/B, V017A/B). These check valves are biased open valves and are fully open during normal operation. These valves will be verified to be open quarterly. In order to exercise these check valves, significant reverse flow must be provided from the DVI line to the CMT. These valves are not tested during power operations because the test would cause undesirable thermal transients on the portion of the line at ambient temperatures and change the CMT boron concentration These valves are not exercised during cold shutdowns because of changes that would result in the CMT boron concentration. Because this parameter is controlled by Technical Specifications, this testing is impractical. These valves are exercised during refueling when the RCS boron concentration is nearly equal to the CMT concentration and the plant is in a mode where the CMTs are not required to be available by the Technical Specifications.

11. This note applies to the PXS containment recirculation check valves (PXS-V119A/B). Squib valves in line with the check valves prevent the use of IRWST water to test the valves. To exercise these check valves an operator must enter the containment, remove a cover from the recirculation screens, and insert a test device into the recirculation pipe to push open the check valve. The test device is made to interface with the valve without causing valve damage. The test device incorporates loads measuring sensors to measure the initial opening and full open force. These valves are not exercised during power operations because of the need to enter highly radioactive areas and because during this test the recirculation screen is bypassed. These valves are not exercised during cold shutdown operations for the same reasons. These valves are exercised during refueling conditions when the recirculation lines are not required to be available by Technical Specifications LCOs 3.5.7 and 3.5.8 and the radiation levels are reduced.

12. This note applies to the PXS IRWST injection check valves (PXS-V122A/B, V124A/B). To exercise these check valves a test cart must be moved into containment and temporary connections made to these check valves. In addition, the IRWST injection line isolation valves must have power restored and be closed. These valves are not exercised during power operations because closing the IRWST injection valve is not permitted by the Technical Specifications and the need to perform significant work inside containment. Testing is not performed during cold shutdown for the same reasons. These valves are exercised during refueling conditions when the IRWST injection lines are not required to be available by Technical Specifications and the radiation levels are reduced.

13. Deleted.

14. Component cooling water system containment isolation motor-operated valves CCS-V200, V207, V208 and check valve CCS-V201 are not exercised during power operation. Exercising these valves would stop cooling water flow to the reactor coolant pumps and letdown heat exchanger. Loss of cooling water may result in damage to equipment or reactor trip. These valves are exercised during cold shutdowns when these components do not require cooling water.

15. Normal residual heat removal system reactor coolant isolation motor-operated valves (RNS-V001A/B, V002A/B) are not exercised during power operation. These valves isolate the high pressure RCS from the low pressure RNS and passive core cooling system (PXS). Opening during normal operation may result in damage to equipment or reactor trip. These valves are exercised during cold shutdowns when the RNS is aligned to remove the core decay heat.

16. Normal residual heat removal system containment isolation motor-operated valves (RNS-V002A/B) are not containment isolation leak tested. The basis for the exception is:

    – The valve is submerged during post-accident operations which prevents the release of the containment atmosphere radiogas or aerosol.
    – The RNS is a closed, seismically-designed safety class 3 system outside containment
    – The valves are closed when the plant is in modes above hot shutdown

17. Normal residual heat removal system containment penetration relief valve (RNS-V021) and containment isolation motor-operated valve (RNS-V023) are subjected to containment leak testing by pressurizing the lines in the reverse direction to the flow which accompanies a containment leak in this path.

18. This note applies to the CAS instrument air containment isolation valves (CAS-V014, V015). It is not practical to exercise these valves during power operation or cold shutdowns. Exercising the valves during these conditions may result in some air-operated valves inadvertently opening or closing, resulting in plant or system transients. These valves are exercised during refueling conditions when system and plant transients would not occur.

19. Primary sampling system containment isolation check valve (PSS-V024) is located inside containment and considerable effort is required to install test equipment and cap the discharge line. Exercise testing is not performed during cold shutdown operations for the same reasons. These valves are exercised during refueling conditions when the radiation levels are reduced.

20. This note applies to the main steam isolation valves and main feedwater isolation valves (SGS-V040A/B, V057A/B). The valves are not full stroke tested quarterly at power since full valve stroking will result in a plant transient during normal power operation. Therefore, these valves will be partially stroked on a quarterly basis and will be full stroke tested on a cold shutdown frequency basis. The full stroke testing will be a full "slow" closure operation. The large size and fast stroking nature of the valve makes it advantageous to limit the number of fast closure operations which the valve experiences. The timed slow closure verifies the valves operability status and that the valve is not mechanically bound.

21. Post-72 hour check valves that require temporary connections for inservice-testing are exercised every refueling outage. These valves require transport and installation of temporary test equipment and pressure/fluid supplies. Since the valves are normally used very infrequently, constructed of stainless steel, maintained in controlled environments, and of a simple design, there is little benefit in testing them more frequently. For example, valve PCS-V039 is a simple valve that is opened to provide the addition of water to the PCS post-72 hour from a temporary water supply. To exercise the valve, a temporary pump and water supply is connected using temporary pipe and fittings, and the flow rate is observed using a temporary flow measuring device to confirm valve operation.

22. Exercise testing of the auxiliary spray isolation valve (CVS-V084, V085) will result in an undesirable temperature transient on the pressurizer due to the actuation of auxiliary spray flow. Therefore, quarterly exercise testing will not be performed. Exercise testing will be performed during cold shutdowns.

23. Thermal relief check valves in the normal residual heat removal suction line (RNS-V003A/B) and the Chemical and Volume Control System makeup line (CVS-V100) are located inside containment. To exercise test these valves, entry to the containment is required and temporary connections made to gas supplies. Because of the radiation exposure and effort required, this test is not conducted during power operation or during cold shutdowns. Exercise testing is performed during refueling shutdowns.

24. Normal residual heat removal system reactor coolant isolation check valves (RNS-V015A/B, V017A/B) are not exercise tested quarterly. During normal power operation these valves isolate the high pressure RCS from the low pressure RNS. Opening during normal operation would require a pressure greater than the RCS normal pressure, which is not available. It would also subject the RCS connection to undesirable transients. These valves will be exercised during cold shutdowns.

25. This note applies to the main feedwater control valves (SGS-V250A/B), moisture separator reheater steam control valve (MSS-V016A/B), turbine control valves (MTS-V002A/B, V004A/B). The valves are not quarterly stroke tested since full stroke testing would result in a plant transient during power operation. Normal feedwater and turbine control operation provides a partial stroke confirmation of valve operability. The valves will be full stroke tested during cold shutdowns.

26. This note applies to containment compartment drain line check valves (SFS-V071, SFS-V072, WLS-V071A/B/C, WLS-V072A/B/C). These check valves are located inside containment and require temporary connections for exercise testing. Because of the radiation exposure and effort required, these valves are not exercised during power operation or during cold shutdowns. The valves will be exercised during refuelings.

27. Containment isolation valves leakage test frequency will be conducted in accordance with the "Primary Containment Leakage Rate Test Program" in accordance with 10 CFR 50 Appendix J. Refer to SSAR subsection 6.2.5.

28. This note applies to the chilled water system containment isolation valves (VWS-V058, V062, V082 and V086). Closing any of these valves stops the water flow to the containment fan coolers. This water flow may be necessary to maintain the containment air temperature within Technical Specification limits. As a result, quarterly exercise testing will be deferred when plant operating conditions and site climatic conditions would cause the containment air temperature to exceed this limit during testing.

29. Exercise testing of the turbine bypass control valves (MSS-V001, V002, V003, V004, V005 and V006) will result in an undesirable temperature transient on the turbine, condenser and other portions of the turbine bypass due to the actuation of bypass flow. Therefore, quarterly exercise testing will not be performed. Exercise testing will be performed during cold shutdowns.

30. These valves are required to operate with low differential pressure. The Combined License applicant will provide an evaluation based on test data to verify that the valves have adequate margin and operability testing is not required. The test data may include data from type tests. See subsection 3.9.8.4 for the Combined License applicant information item.

31 These valves may be subject to operability testing. See subsection 3.9.6.2.2 for the factors to be considered in the evaluation of operability testing and subsection 3.9.8.4 for the Combined License information item. The specified frequency for operability testing is a maximum of once every 10 years. The test frequency is the longer of every 3 refueling cycles or 5 years until sufficient data exists to determine a longer test frequency is appropriate in accordance with Generic Letter 96-05. Some of the valves will be tested the first time after a shorter period to provide for trending information.

32. These valves are subject to leak testing to support the nonsafety-related classification of the CVS purification subsystem inside containment. These valves are not included in the PIV integrity Technical Specification 3.4.16. The leakage through valves CVS-V001, CVS-V002, and CVS-V080 will be tested separately with a leakage limit of 1.5 gpm for each valve. The leakage through valves CVS-V081, V082, V084, and V085 will be tested at the same time as a group with a leakage limit of 1 gpm for the group. The leak tests will be performed at reduced RCS pressures. The observed leakage at lower pressures can be assumed to be the leakage at the maximum pressure as long as the valve leakage is verified to diminish with increasing pressure differential. Verification that the valves have the characteristic of decreasing leakage with pressure may be provided with two tests at different test pressures. The test requirements including the minimum test pressure and the difference between the test pressures will be defined by the Combined License applicant in the inservice test program.

33. This note applies to valve FHS-V001. This valve closes one end of the fuel transfer tube. The fuel transfer tube is normally closed by a flange except during refuelings. This valve has an active safety function to close when the fuel transfer tube flange is removed and normal shutdown cooling is lost. Closing this valve, along with other actions, provides containment closure which allows long term core cooling to be provided by the PXS. As a result this valve is only required to be operable during refueling operations. The exercise testing of this valves will be performed during refueling shutdowns prior to removing the fuel transfer tube flange.

34. This note applies to the moisture separator reheater steam control valve (MSS-V016A/B), turbine control valves (MTS-V002A/B, V004A/B), main turbine stop valves (MTS-V001A/B, V003A/B), the turbine bypass control valves (MSS-V001, V002, V003, V004, V005, V006). These valves are not safety-related. These valves are relied on in the safety analyses for those cases in which the rupture of the main steam or feedwater piping inside containment is the postulated initiating event. These valves are credited in single failure analysis to mitigate the event.

35. This note applies to the turbine stop valves (MTS-V001A/B, V003A/B). The valves are not quarterly stroke tested since full stroke testing would result in a plant transient during power operation. The valves will be full stroke tested during cold shutdowns.

36. In each of the four turbine inlet lines, there is a turbine stop valve and turbine control valve. Only one of the valves in each of the four lines is required by Technical Specification 3.7.2 to be operable.

Table 3.9-17

SYSTEM LEVEL OPERABILITY TEST REQUIREMENTS

System/Feature	Test Purpose	Test Method	Tech Spec[a]
PCS			
PCCWST drain lines	Flow capability and water coverage	Note 1	SR 3.6.6.6
PXS			
Accumulator injection lines	Flow capability	Note 2	SR 3.5.1.6
CMT injection lines	Flow capability	Note 3	SR 3.5.2.7
PRHR HX	Heat transfer capability	Note 4	SR 3.5.4.5
IRWST injection lines	Flow capability	Note 5	SR 3.5.6.9
Containment recirculation lines	Flow capability	Note 6	SR 3.5.6.9
VES			
MCR isolation/makeup	MCR pressurization capability	Note 7	SR 3.7.6.9

Alpha Note:

a. Refer to the Technical Specification surveillance identified in this column for the test frequency.

Notes:

1. The flow capability of each PCS water drain line is demonstrated by conducting a test where water is drained from the PCS water storage tank onto the containment shell by opening two of the three parallel isolation valves. During this flow test the water coverage is also demonstrated. The test is terminated when the flow measurement is obtained and the water coverage is observed. The minimum allowable flow rate is 469.1 gpm with the passive containment cooling water storage tank level 27.3 feet above the lowest standpipe. The test may be run with a higher water level and the test results adjusted for the increased level. Water coverage is demonstrated by visual inspection that there is unobstructed flow from the lower weirs. In addition, at least four air baffle panels will be removed at the containment vessel spring line, approximately 90 degrees apart, to permit visual inspection of the water coverage and the vessel coating. The water coverage observed at these locations will be compared against the coverage measured at the same locations during pre-operational testing (see item 7.(b)(i) of ITAAC Table 2.2.2-6).

2. The flow capability of each accumulator is demonstrated by conducting a test during cold shutdown conditions. The initial conditions of the test include reduced accumulator pressure. Flow from the accumulator to the RCS is initiated by opening the accumulator isolation valve. Sufficient flow is provided to fully open the check valves. The test is terminated when the flow measurement is obtained. The allowable calculated flow resistance between each accumulator and the reactor vessel is $\geq 1.47 \times 10^{-5}$ ft/gpm^2 and $\leq 1.83 \times 10^{-5}$ ft/gpm^2.

3. The flow capability of each CMT is demonstrated by conducting a test during cold shutdown conditions. The initial conditions of the test include the RCS loops drained to a level below the top of the RCS hot leg. Flow from the CMT to the RCS is initiated by opening one CMT isolation valve. The test is terminated when the flow measurement is obtained. The allowable calculated flow resistance between each CMT and the reactor vessel is $\geq 1.83 \times 10^{-5}$ ft/gpm^2 and $\leq 2.25 \times 10^{-5}$ ft/gpm^2.

4. The heat transfer capability of the passive residual heat exchanger is demonstrated by conducting a test during cold shutdown conditions. The test is conducted with the RCPs in operation and the RCS at a reduced temperature. Flow through the heat exchanger is initiated by opening one outlet isolation valve. The test is terminated when the flow and temperature measurements are obtained. The allowable calculated heat transfer is ≥ 1.04E8 Btu/hr with an inlet temperature of 250°F and an IRWST temperature of 120°F and the design basis number of tubes plugged.

5. The flow capability of each IRWST injection line is demonstrated by conducting flow tests and inspections. A flow test is conducted to demonstrate the flow capability of the injection line from the IRWST through the IRWST injection check valves. Water flow from the IRWST through the IRWST injection check valve demonstrates the flow capability of this portion of the line. Sufficient flow is provided to fully open the check valves. The test is terminated when the flow measurement is obtained. The allowable calculated flow resistance from the IRWST to each injection line check is: Line A: $\geq 5.53 \times 10^{-6}$ ft/gpm^2 and $\leq 9.20 \times 10^{-6}$ ft/gpm^2 and Line B: $\geq 6.21 \times 10^{-6}$ ft/gpm^2 and $\leq 1.03 \times 10^{-5}$ ft/gpm^2.

   The flow capability of the portion of the line from the IRWST check valves to the DVI line is demonstrated by conducting an inspection of the inside of the line. The inspection shows that the lines are not obstructed. It is not necessary to operate the IRWST injection squib valves for this inspection.

6. The flow capability of each containment recirculation line is demonstrated by conducting an inspection. The line from the containment to the containment recirculation squib valve is inspected from the containment side. The line from the squib valve to the IRWST injection line is inspected from the IRWST side. The inspection shows that the lines are not obstructed. It is not necessary to operate the containment recirculation squib valves for this inspection.

7. The MCR pressurization capability is demonstrated by conducting a test. The test is conducted with the normal HVAC lines connected to the MCR isolated using the dampers in VBS designated for this purpose in subsection 9.4.1. Pressurization of the MCR is initiated by opening one of the emergency MCR habitability air supply lines. The air supply lines are alternated for subsequent tests. The test is a limited duration test and is terminated when the MCR pressurization is measured. The minimum allowable MCR pressurization is 1/8 inch gauge pressure relative to the surrounding areas, with 65 ± 5 scfm air flow supplied by the emergency MCR habitability air supply line.

Table 3.9-18

AP1000 PRESSURE ISOLATION VALVES

Valve Number	Description
PXS-V028A PXS-V028B PXS-V029A PXS-V029B	Accumulator Discharge Check Valves
RNS-V001A RNS-V001B RNS-V002A RNS-V002B	RNS Hot Leg Suction Isolation Valves
RNS-V015A RNS-V015B RNS-V017A RNS-V017B	RNS Discharge RCS Pressure Boundary

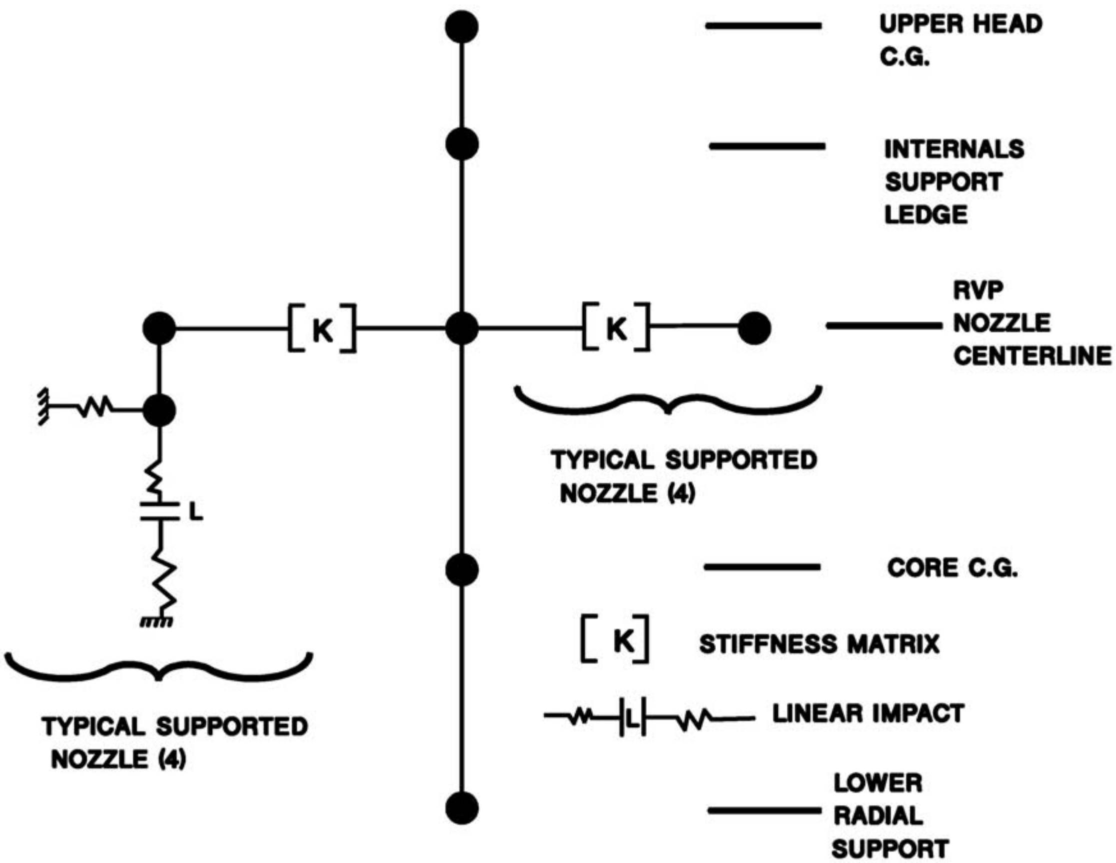


Figure 3.9-1

Reactor Vessel Submodel

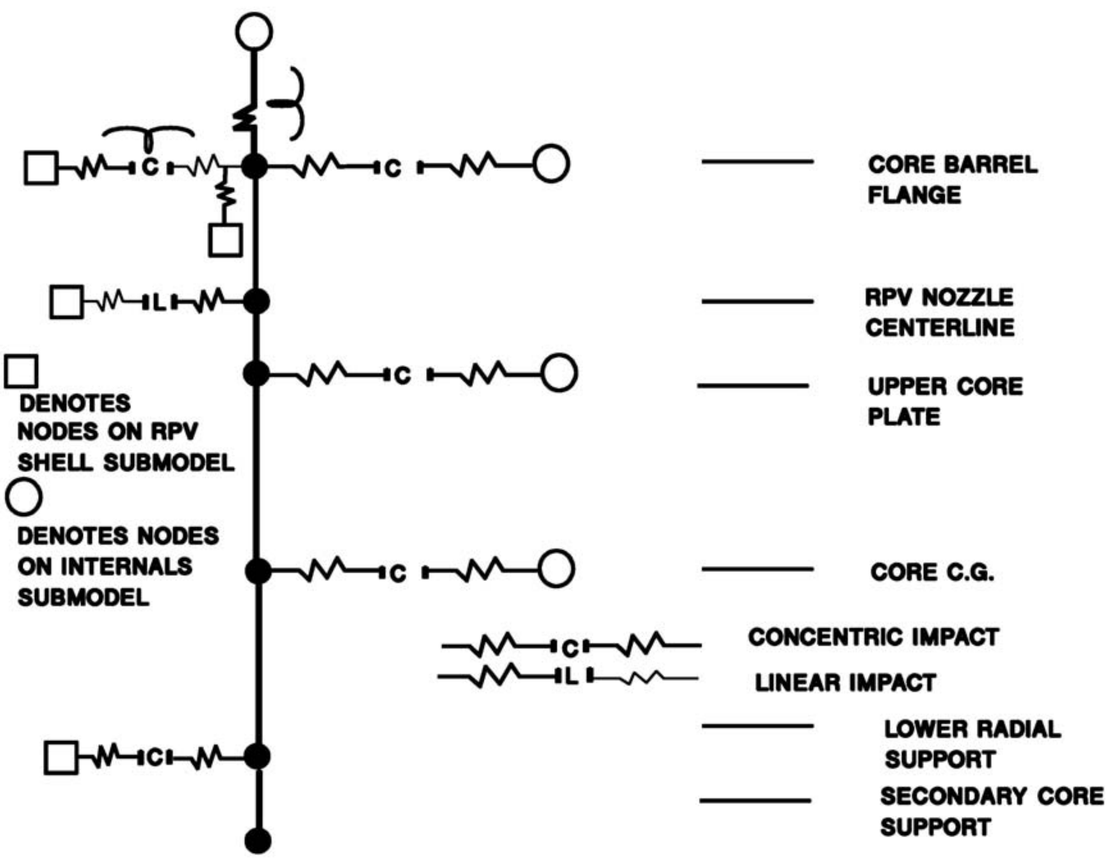


Figure 3.9-2

Reactor Vessel Lower Internals Submodel

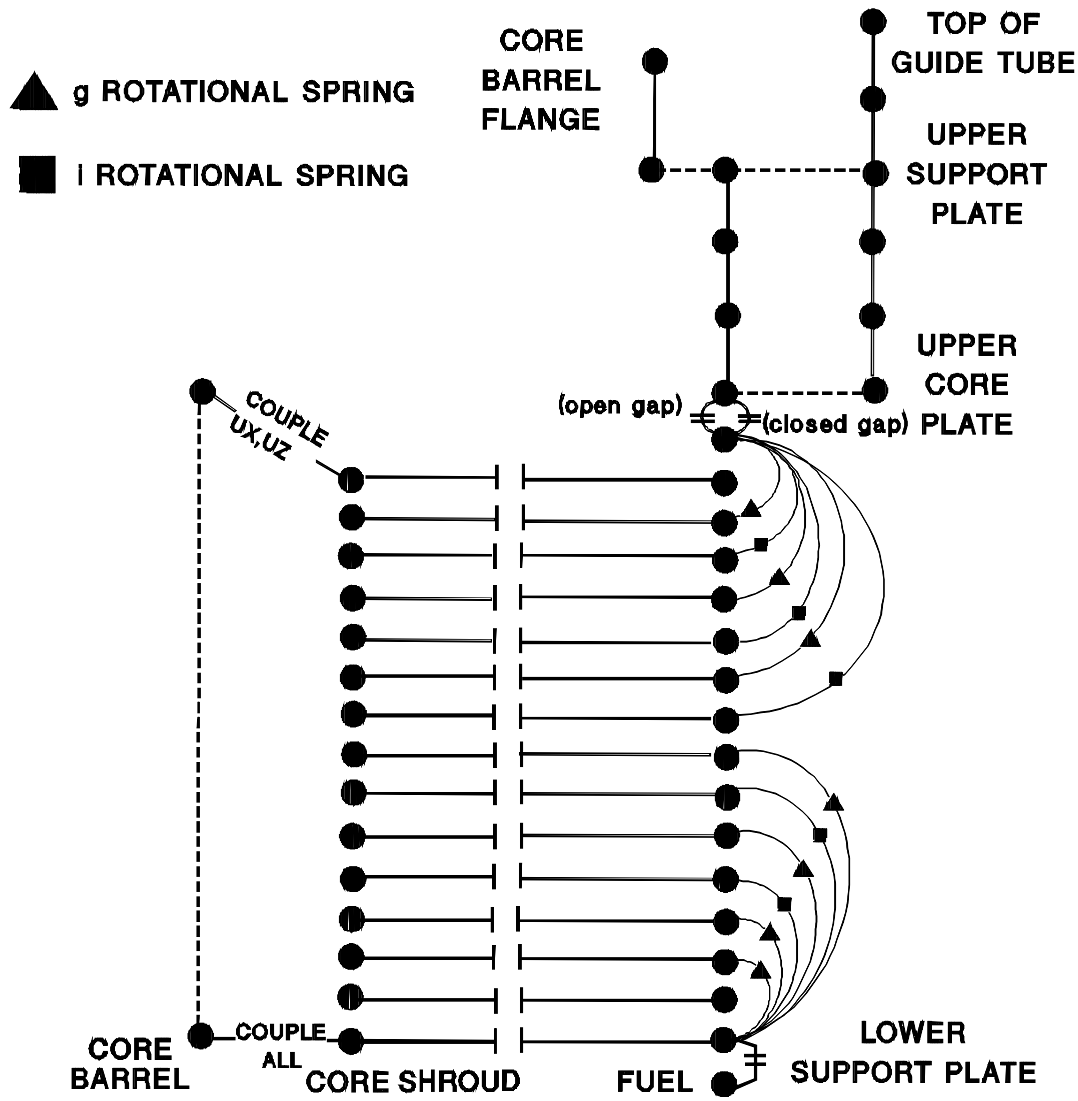


Figure 3.9-3

Reactor Vessel Upper Internals and Fuel Submodel

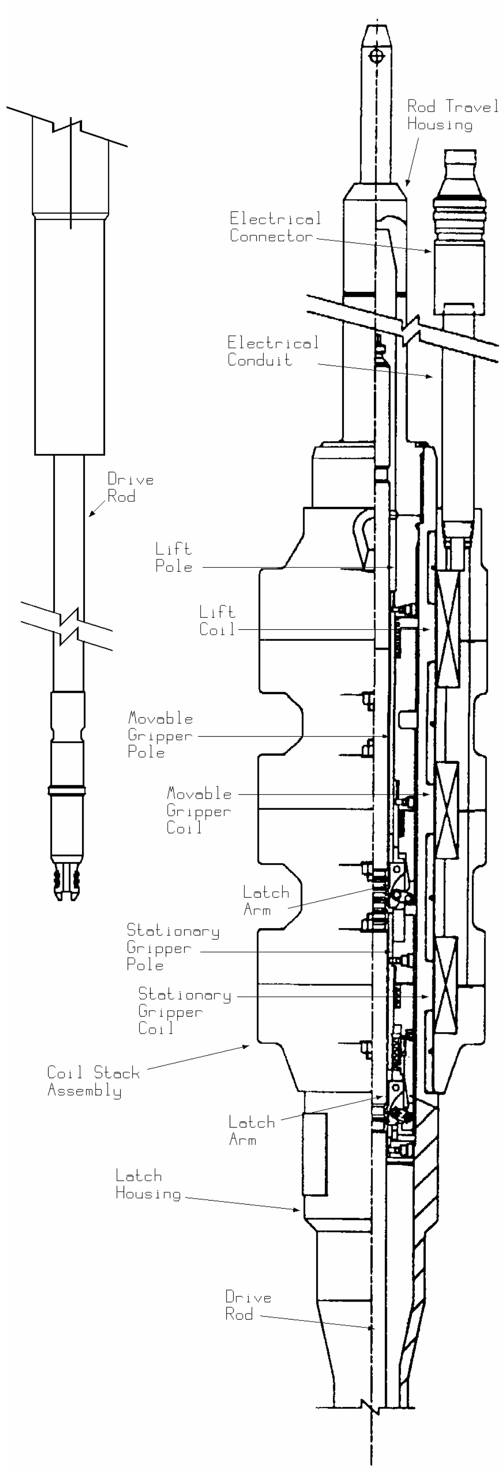


Figure 3.9-4

Control Rod Drive Mechanism

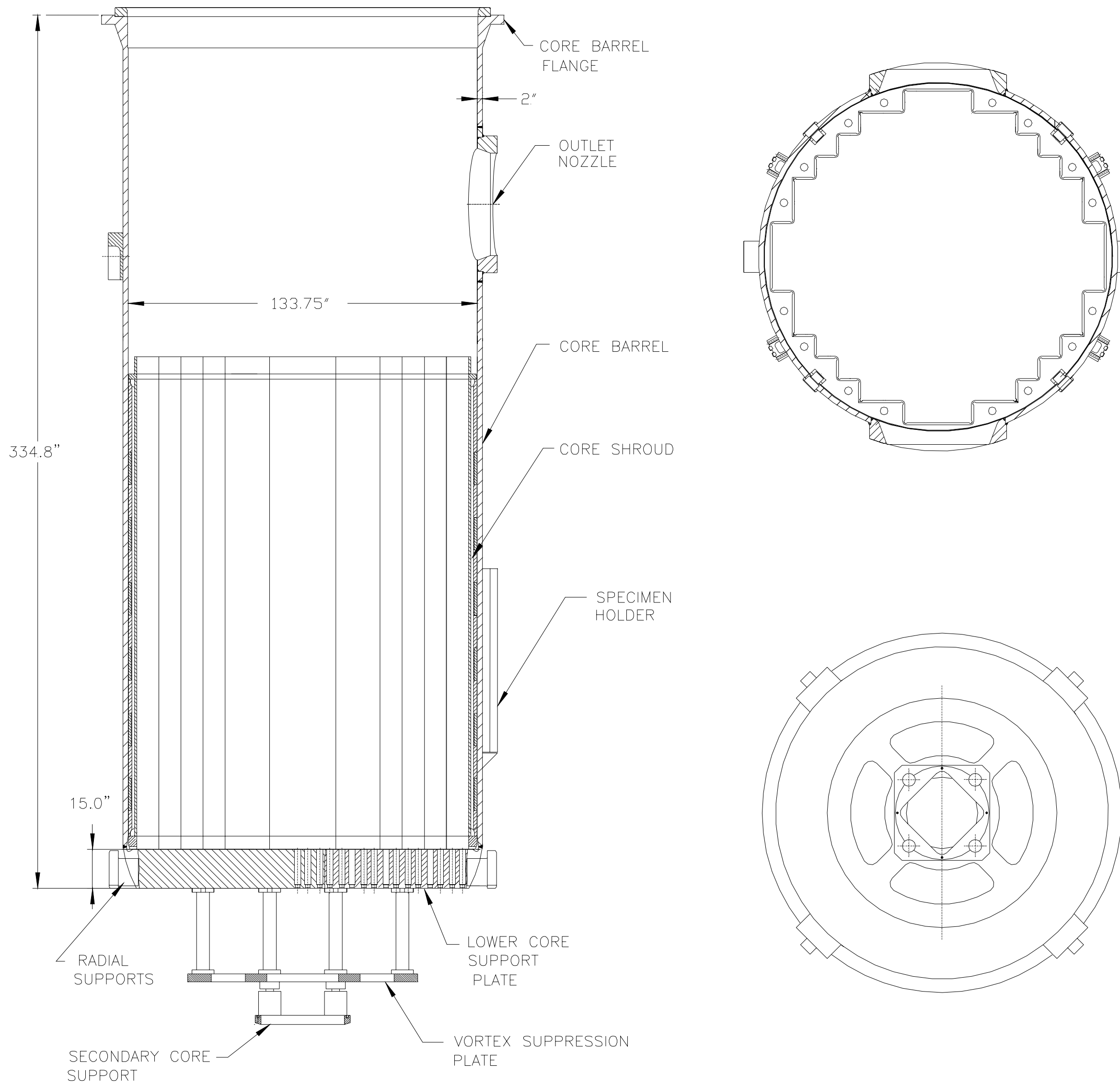


Figure 3.9-5

Lower Reactor Internals

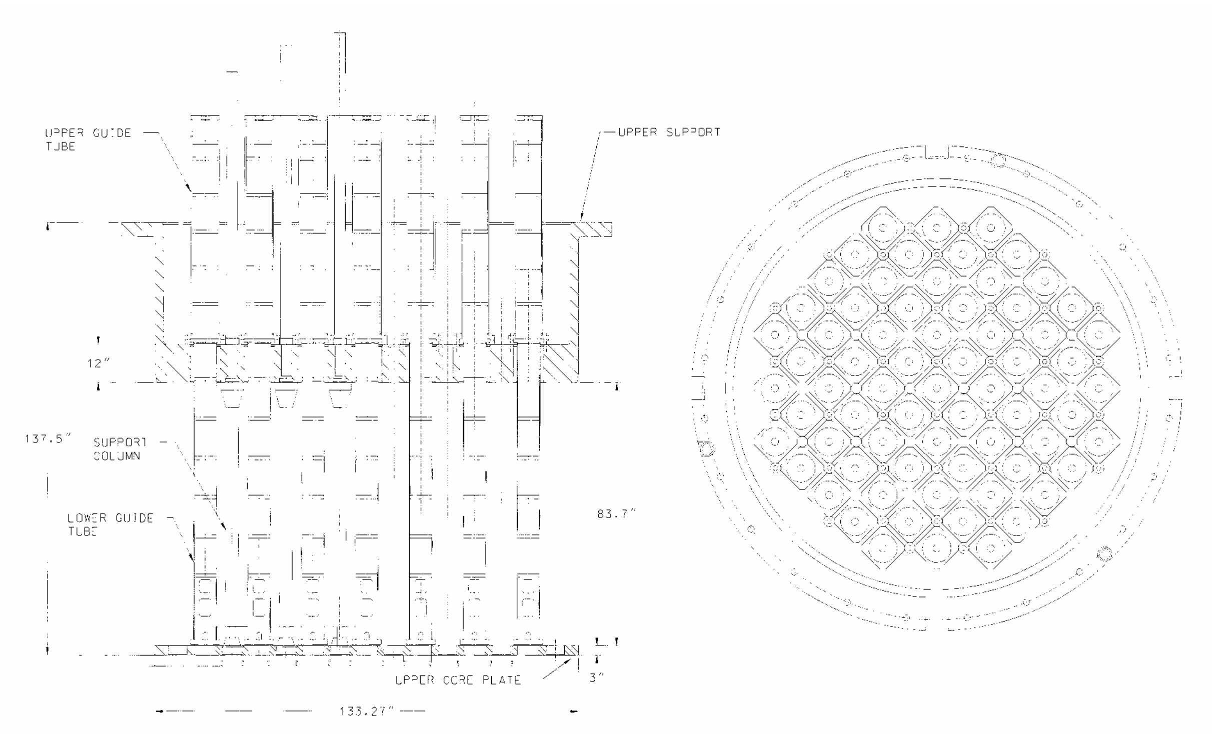


Figure 3.9-6

Upper Core Support Structure

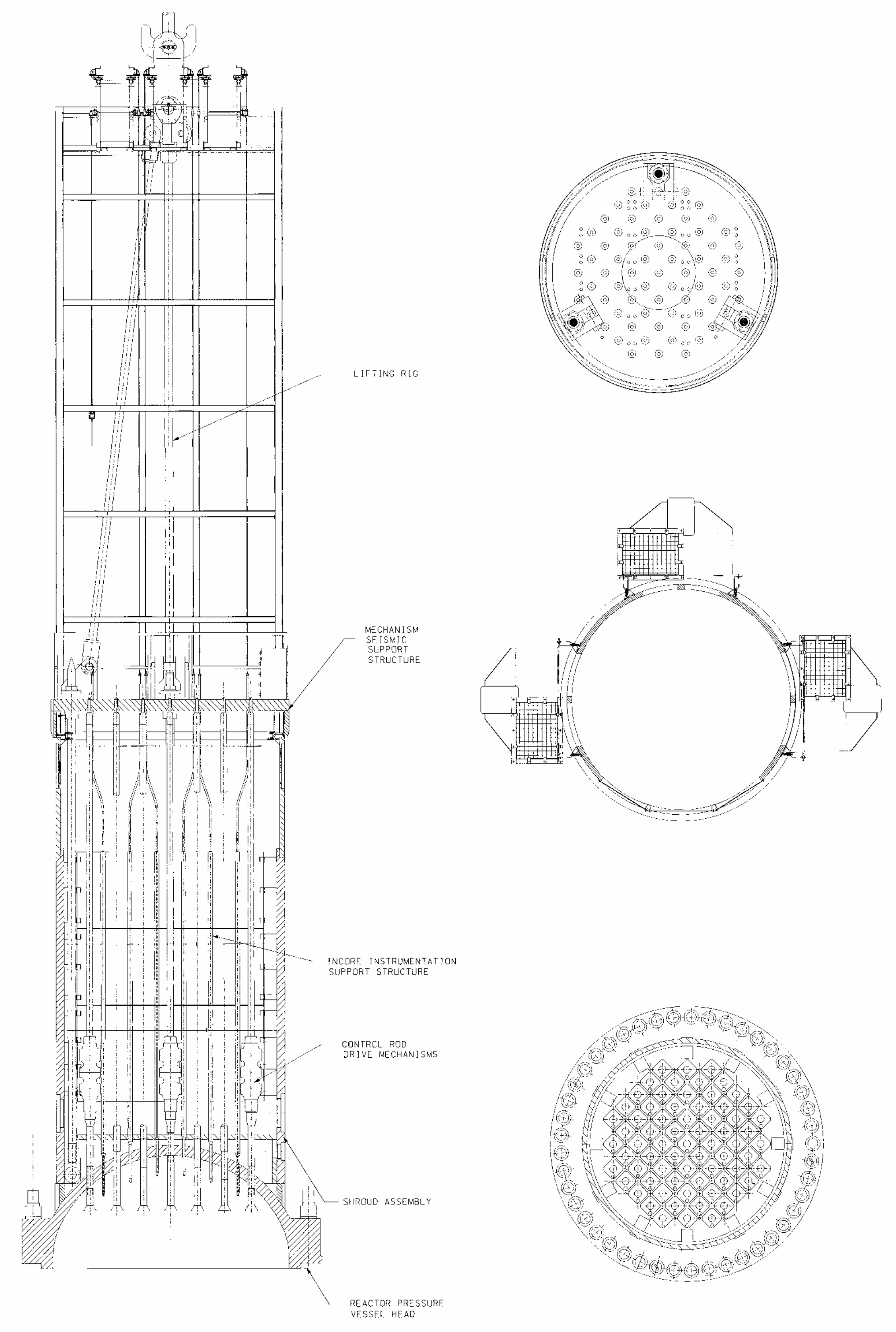


Figure 3.9-7

Integrated Head Package

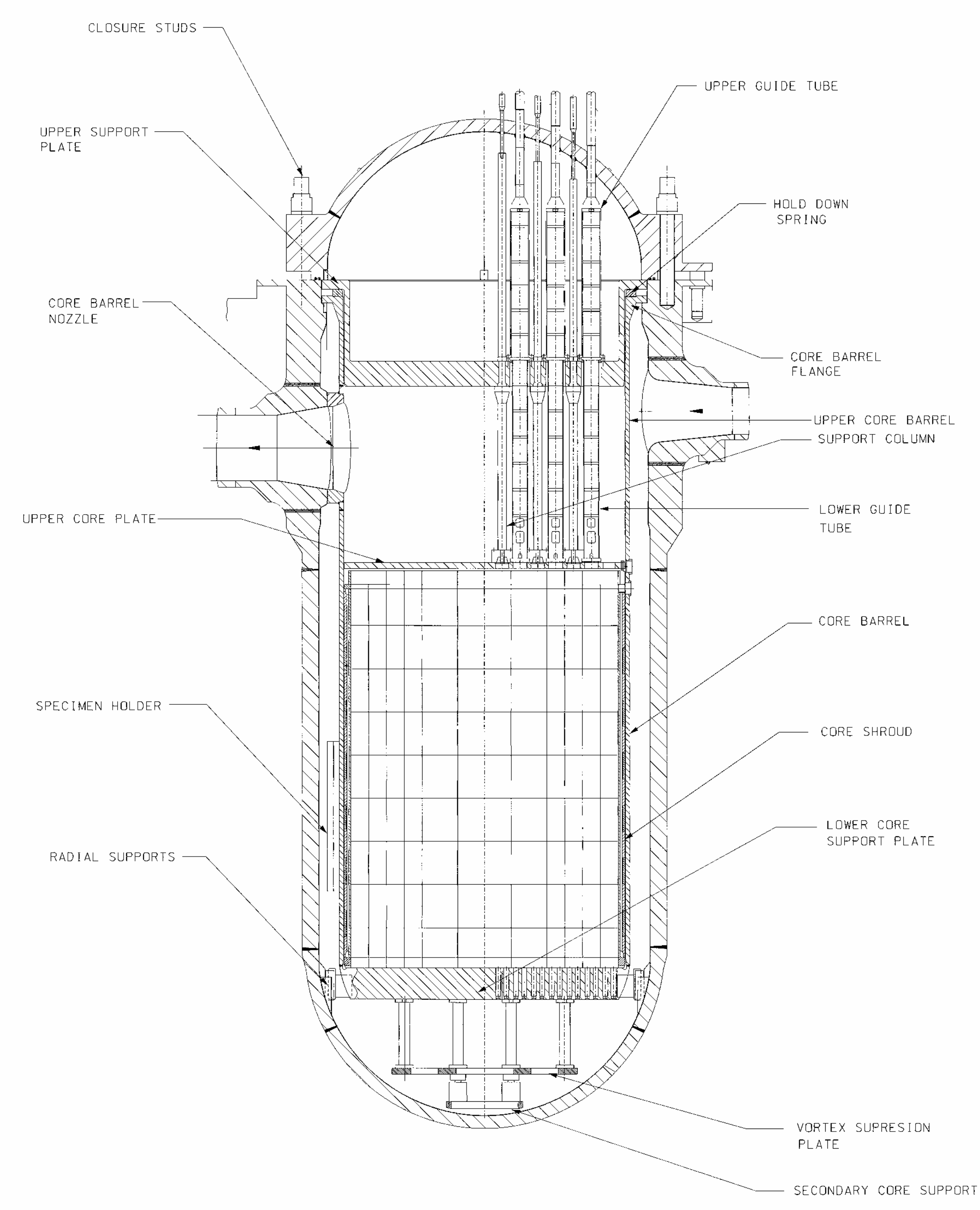


Figure 3.9-8

Reactor Internals Interface Arrangement

3.10 Seismic and Dynamic Qualification of Seismic Category I Mechanical and Electrical Equipment

Safety-related equipment and selected portions of post-accident monitoring equipment are classified as seismic Category I, as discussed in subsection 3.2.1.1. This section addresses the seismic and dynamic qualification of this equipment other than piping and includes the following types:

- Safety-related instrumentation and electrical equipment and certain monitoring equipment.

- Safety-related active mechanical equipment that performs a mechanical motion while accomplishing a system safety-related function. These devices include the control rod drive mechanisms; HVAC dampers; and certain valves.

- Safety-related, nonactive mechanical equipment whose mechanical motion is not required while accomplishing a system safety-related function, but whose structural integrity must be maintained in order to fulfill its design safety-related function.

This section presents or references information to demonstrate that mechanical equipment, electrical equipment, instrumentation, and, where applicable, their supports classified as seismic Category I are capable of performing their designated safety-related functions under the full range of normal and accident (including seismic) loadings. This equipment includes devices associated with systems essential to safe shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal, or are otherwise essential in preventing significant release of radioactive material to the environment or in mitigating the consequences of accidents. The information presented or referenced includes:

- Identification of the seismic Category I instrumentation, electrical equipment, and appropriate mechanical equipment

- Qualification criteria employed for each type of equipment

- Designated safety-related functional requirements

- Definition of the applicable seismic environment

- Definition of other normal and accident loadings

- Documentation of the qualification process employed to demonstrate the required structural integrity and operability of mechanical and electrical equipment and instrumentation in the event of a safe shutdown earthquake (SSE) after a number of postulated occurrences of an earthquake smaller than a safe shutdown earthquake in combination with other relevant dynamic and static loads.

3.10.1 Seismic and Dynamic Qualification Criteria

3.10.1.1 Qualification Standards

The methods of meeting the general requirements for the seismic and dynamic qualification of seismic Category I mechanical and electrical equipment and instrumentation as described by General Design Criteria (GDC) 1, 2, 4, 14, 23, and 30 are described in Section 3.1. The general methods of implementing the requirements of Appendix B to 10CFR50 are described in Chapter 17.

The Nuclear Regulatory Commission (NRC) recommendations concerning the methods employed for seismic qualification of mechanical and electrical equipment are contained in Regulatory Guide 1.100, which endorses IEEE 344-1987 (Reference 1).

[*AP1000 meets IEEE 344-1987, as modified by Regulatory Guide 1.100, by either type testing or analysis or by an appropriate combination of these methods*]* employing the methodology described in Appendix 3D.

The guidance provided in the ASME Code, Section III, is followed in the design of seismic Category I mechanical equipment to achieve the structural integrity of pressure boundary components. In addition, the AP1000 implements an operability program for active valves following Regulatory Guide 1.148, as addressed in subsection 1.9.1 and in Section 3.9.

Testing is the preferred method to qualify equipment. Both dynamic and static test approaches are used to demonstrate structural integrity and operability of mechanical and electrical equipment in the event of a safe shutdown earthquake preceded by five earthquakes of a magnitude equal to 50 percent of the calculated safe shutdown earthquake. Test samples are selected according to type, load level, and size, as well as other pertinent factors on a prototype basis.

Analysis using mathematical modeling techniques correlated to tests performed on similar equipment or structures and verified analytical approaches are used to qualify equipment. Combined analysis and testing is also used to qualify equipment.

The analytical approach to seismic qualification without testing is used under the following conditions:

- If only maintaining structural integrity is required for the safety-related function
- If the equipment is too large or heavy to obtain a representative test input at existing test facilities. (The essential control devices and electrical parts of large equipment are tested separately if required.)
- If the interfaces (for example, interconnecting cables to the cabinet or other complex inputs) cannot be conservatively considered during testing
- If the response of the equipment is essentially linear or has a simple nonlinear behavior that can be predicted by conservative analytical methods.

*NRC Staff approval is required prior to implementing a change in this material; see DCD Introduction Section 3.5.

A combination of testing and analysis is used when complete testing is not practical.

Equipment that has been previously qualified by means of test and analysis equivalent to those described herein are acceptable provided that proper documentation is submitted.

3.10.1.2 Performance Requirements for Seismic Qualification

An equipment qualification data package (EQDP) is developed for every item of instrumentation and electrical equipment classified as seismic Category I. Table 3.11-1 of Section 3.11 identifies the seismic Category I electrical equipment and instrumentation supplied for the AP1000. Each equipment qualification data package contains a section entitled "Performance Requirements." This specification establishes the safety-related functional requirements of the equipment to be demonstrated during and after a seismic event. The test response spectrum employed by the AP1000 for generic seismic qualification is also identified in the specification.

For active seismic Category I mechanical components, the performance requirements are defined in the appropriate design and equipment specifications. Requirements for active valves and HVAC dampers are discussed in subsection 3.10.2.2. The equipment qualification data packages are referenced in subsection 3.10.4. For other seismic Category I mechanical components, the only performance requirement is to maintain structural integrity under appropriate loading conditions.

A master list and summary of seismic qualification of safety-related Category I electrical and mechanical equipment are maintained as part of the equipment qualification file.

3.10.1.3 Performance Criteria

Seismic and dynamic loading qualification demonstrates that Category I instrumentation and electrical equipment and active valves and dampers are capable of performing their designated safety-related functions under applicable plant loading conditions, including the safe shutdown earthquake. The qualification also demonstrates the structural integrity of seismic Category I nonactive valves, mechanical supports, and structures. Some permanent deformation of supports and structures is acceptable at the safe shutdown earthquake level, provided that the capability to perform the designated safety-related functions is not impaired.

3.10.2 Methods and Procedures for Qualifying Electrical Equipment, Instrumentation, and Mechanical Components

Seismic qualification of seismic Category I instrumentation and electrical equipment is demonstrated by either type testing or a combination of test and analysis. The qualification method employed by the AP1000 for a particular item of equipment is based upon many factors including practicability, complexity of equipment, economics, and availability of previous seismic qualification. The qualification method employed for a particular item of instrumentation or electrical equipment is identified in the individual equipment qualification data package.

For active valves and dampers the AP1000 uses a combination of tests and analyses to demonstrate the structural integrity and operability of such components. Other seismic Category I mechanical equipment is qualified by analysis to demonstrate structural integrity.

The methods of load combination and methods of combining dynamic responses for mechanical equipment are discussed in Section 3.9. For instrumentation and electrical equipment, the only dynamic loads considered in testing are seismic loads and hydrodynamic and vibratory loads where applicable. Other dynamic loads to which instrumentation and electrical equipment may be subjected are enveloped by this testing or are addressed by analysis.

The seismic qualification of Class 1E safety-related equipment and active valves and dampers may be based on properly documented experience data. [*Seismic qualification based on experience is performed in accordance with Section 9.0 of IEEE 344-1987 on a case-by-case basis. In such cases where experience data are used, aspects of the methodology, qualification basis, and supporting data will be properly documented by the Combined License applicant.*]* Identification of the specific equipment qualified based on experience and the details of the methodology and the corresponding experience data for each piece of equipment are included in the equipment qualification file. The Combined License applicant will identify the specific equipment and include details of the methodology and the corresponding experience data for each piece of equipment.

3.10.2.1 Seismic Qualification of Instrumentation and Electrical Equipment

3.10.2.1.1 Type Testing

For seismic Category I instrumentation and electrical equipment, seismic qualification by test is performed according to IEEE 344-1987. Where testing is used, multifrequency, multiaxis inputs are developed by the general procedures outlined in Appendix 3D. The test results contained in the individual equipment qualification data packages demonstrate that the measured test response spectrum envelops the required response spectrum defined in the equipment qualification data package.

Alternative test methods, such as single-frequency, single-axis inputs for line-mounted equipment, are used in selected cases as permitted by IEEE 344-1987 and Regulatory Guide 1.100. These methods are further described in Appendix 3D.

3.10.2.1.2 Test and Analysis

The AP1000 also uses a combination of test and analysis to qualify seismic Category I instrumentation and electrical equipment. The test methods are similar to those described for type testing. Available test results are employed in combination with the analysis methods described in IEEE 344-1987 to demonstrate seismic qualification. The analytical methods include both static and dynamic techniques, which are described in detail in Appendix 3D.

3.10.2.2 Seismic and Operability Qualification of Active Mechanical Equipment

Active mechanical equipment is qualified for both structural integrity and operability for its intended service conditions by a combination of test and analysis. These methods address such loading conditions as thermal transients, flow loads where significant, and degraded flow conditions if applicable. The test and analysis methods utilized in qualification of these components provide adequate confidence of operability under required plant conditions.

*NRC Staff approval is required prior to implementing a change in this material; see DCD Introduction Section 3.5.

Qualification methods used for active valves and dampers are described in this subsection. The qualification methods used for control rod drive mechanisms and snubbers are described in Section 3.9. The qualification program for valves that are part of the reactor coolant pressure boundary shall include testing or analysis that demonstrate that these valves will not experience leakage beyond the limits defined in the design specification for each valve when subjected to design loading.

Safety-related active valves, listed in Table 3.11-1, function at the time of an accident. Confidence is provided that these valves operate during a seismic event. Tests and analyses are conducted to qualify active valves.

The safety-related valves are subjected to a series of tests before service and during the plant life. Before installation, the following tests are performed: body hydrostatic test to ASME Code, Section III, requirements, back-seat and main seat leakage tests, disc hydrostatic tests, and operational tests to verify that the valve opens and closes. For the qualification of motor operators for environmental conditions, see Section 3.11. After installation, the valves undergo system level hydrostatic tests, construction acceptance tests, and preoperational tests. Where applicable, periodic in-service inspections and operations are performed in situ to verify the functional capability of the valve. On active valves, an analysis of the extended structure is performed for static equivalent seismic safe shutdown earthquake loads applied at the center of gravity of the extended structure. The maximum stress limits used for active Class 1, 2, and 3 valves are compared to acceptable standards in the ASME Code. Valve discs are evaluated for maximum design line pressure and maximum differential pressure resulting from plant operating, transient, and accident conditions. Feedwater line valve discs are evaluated, using appropriate ASME Code, Section III limits, for the effect of dynamic loads by considering the effect of an equivalent differential pressure. The equivalent differential pressure is developed from a transient analysis based on wave mechanics that includes consideration of system arrangement and valve closing dynamics. Valve operating conditions are included as part of the valve design specification and are used to evaluate the valve disc. Additional information is provided on the controlled-closure, feedwater check valve in subsection 10.4.7.2.2.

In addition to these tests and analyses, representative valves of each design type having extended structures are subjected to static pull tests and nozzle load tests as appropriate. These tests verify operability of a rigid valve (natural frequency equaling or exceeding 33 hertz) during a simulated plant faulted-condition event by demonstrating operational capabilities within the specified limits. A representative valve of a specific design type is identified for this testing by the specification (for example, globe valve, motor-operated valve) for that particular type of valve. A further subdivision of design is based upon the valve size, pressure rating, type of operator, and previous operability testing to evaluate the need for additional testing of a particular design type. The testing procedures are described in Appendix 3D.

The accelerations used for the static valve qualification are equivalent, as justified by analysis, to 6.0g in two orthogonal horizontal directions and 6.0g vertical. These values are derived from the test response spectra in IEEE 382-1996. The piping design maintains the operator accelerations to these levels. If the natural frequency of the valve is less than 33 hertz, a dynamic analysis of the valve is performed to determine the equivalent acceleration to be applied during the static test.

Valves that are safety related but are classified as not having an extended structure, such as check valves and safety valves, are considered separately.

Check valves are characteristically simple in design. Their operation is not affected by seismic accelerations or the maximum applied nozzle loads. These valves are designed so that once the structural integrity of the valve is verified using standard methods, the capability of the valve to operate is demonstrated by its design features. The valve also undergoes in-shop hydrostatic and seat leakage tests, and periodic in situ valve exercising and inspection to verify the functional capability of the valve.

The pressurizer safety valves are qualified by the following procedures (these valves are also subjected to tests and analysis similar to check valves): stress and deformation analyses of critical items that affect operability for faulted condition loads, in-shop hydrostatic and seat leakage tests, and periodic in situ valve inspection. In addition to these tests, a static load equivalent to that applied by the faulted condition is applied at the top of the bonnet, and the pressure is increased until the valve mechanism actuates. Successful actuation within the design requirements of the valve demonstrates its overpressurization safety capabilities during a seismic event.

Safety-related active dampers mounted in HVAC ductwork used to isolate main control room areas during design events are listed in Table 3.11-1. These dampers are qualified to operate on demand using electro-hydraulic operators.

Using these methods, the safety-related valves and dampers are qualified for operability during a faulted event. These methods conservatively simulate the seismic event and demonstrate that the active valves and dampers perform their safety-related function when necessary.

3.10.2.3 Valve Operator Qualification

Active valve motor operators, position sensors, and solenoid valves are seismically qualified according to IEEE 382-1996, as discussed in the appropriate equipment qualification data packages.

3.10.2.4 Seismic Qualification of Other Seismic Category I Mechanical Equipment

For seismic Category I mechanical equipment not defined as active the AP1000 uses analysis to demonstrate structural integrity. The analysis methods are described in Sections 3.7 and 3.9 and in Appendix 3D.

3.10.3 Method and Procedures for Qualifying Supports of Electrical Equipment, Instrumentation, and Mechanical Components

The equipment qualification data packages identify the equipment mounting employed for qualification and establish interface requirements for the equipment to provide confidence that subsequent in-plant installation does not prejudice the established qualification. Interface requirements are defined based on the test configuration and other design requirements. Dynamic coupling effects resulting from mounting the component according to these interface criteria are considered in the qualification program.

Information concerning the structural integrity of pressure-retaining components, their supports, and core supports is presented in Section 3.9.

The following bases are used in the design and analysis of cable tray supports and instrument tubing supports:

- The methods used in the seismic analysis of cable tray supports are described in Appendix 3F.

- The seismic Category I instrument tubing systems are supported so that the allowable stresses permitted by ASME Code, Section III, are not exceeded when the tubing is subjected to the loads specified in Section 3.9.

3.10.4 Documentation

The results of tests and analyses verifying that the criteria established in subsection 3.10.1 are satisfied, employing the qualification methods described in subsections 3.10.2 and 3.10.3, are included in the individual equipment qualification data packages and test reports. The Combined License applicant is responsible for maintaining the equipment qualification file during the equipment selection and procurement phase (see subsection 3.11.5).

Seismic qualification of equipment is documented in equipment qualification data packages, test reports, analysis reports, and calculation notes. Appendix 3D provides guidance in this area.

3.10.5 Standard Review Plan Evaluation

A summary describing the Standard Review Plan differences in regard to seismic and dynamic qualification of mechanical and electrical equipment is provided subsection 1.9.2.

3.10.6 Combined License Information Item on Experienced-Based Qualification

[*The Combined License applicant will address, as part of the Combined License application, identification of the equipment qualified based on experience and include details of the methodology and the corresponding experience data. The corresponding experience data for each piece of equipment will be included in the equipment qualification file.*]*

3.10.7 References

1. IEEE 344-1987, " Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations."

*NRC Staff approval is required prior to implementing a change in this material; see DCD Introduction Section 3.5.

3.11 Environmental Qualification of Mechanical and Electrical Equipment

This section presents information to demonstrate that the mechanical and electrical portions of the engineered safety features, the reactor protection systems, and selected portions of the post-accident monitoring system are capable of performing their designated functions while exposed to applicable normal, abnormal, test, accident, and post-accident environmental conditions. The information presented includes identification of the equipment required to be environmentally qualified and, for each item of equipment, the designated functional requirements, definition of the applicable environmental parameters, and documentation of the qualification process employed to demonstrate the required environmental capability. The seismic qualification of mechanical and electrical equipment is presented in Section 3.10. The portions of post-accident monitoring equipment required to be environmentally qualified are identified in Table 7.5-1.

3.11.1 Equipment Identification and Environmental Conditions

3.11.1.1 Equipment Identification

A complete list of environmentally qualified electrical and mechanical equipment that is essential to emergency reactor shutdown, containment isolation, reactor core cooling, or containment and reactor heat removal, or that is otherwise essential in preventing significant release of radioactive material to the environment, is provided in Table 3.11-1. A list of environmentally qualified electrical and mechanical equipment and a summary of electrical and mechanical equipment qualification results are maintained as part of the equipment qualification file. The Combined License applicant is responsible for verification that the equipment qualification file is maintained during the equipment selection and procurement phase.

3.11.1.2 Definition of Environmental Conditions

Appendix 3D identifies applicable normal, abnormal, and design basis accident environmental conditions conforming to General Design Criterion 4. These environmental conditions are associated with various plant areas by an environmental zone, as noted in Table 3D.5-1 and Table 3.11-1.

For mild environments, the area conditions do not change as the result of an accident. There are no degrading environmental effects that lead to common mode failure of the equipment. The qualification of mechanical and electrical equipment located in a mild environment is demonstrated by conducting the plant surveillance activities carried out during the operational phase of the plant.

The environmental conditions identified in Appendix 3D are defined as follows.

Normal operating environmental conditions are defined as those conditions existing during routine plant operations for which the equipment is expected to be available on a continuous basis to perform required functions.

Abnormal environmental conditions are those plant conditions for which the equipment is designed to operate for a period of time without accelerating normal periodic tests, inspections,

and maintenance schedules for that equipment. The maximum and minimum conditions identified as the abnormal condition are based on the design limits for the affected areas.

Design basis accident (DBA) and post-design basis accident conditions are those plant conditions resulting from various postulated equipment and piping failures during which the equipment identified in Table 3.11 must operate without impairment of the function. The design basis accident and post-design basis accident conditions are discussed in Appendix 3D.

Compatibility of equipment with the specified environmental conditions is achieved by the following.

Systems and components required to mitigate the consequences of a design basis accident or to perform safe shutdown operation are qualified to remain functional after exposure to the environmental conditions in Table 3D.5-5.

Environmentally qualified equipment exposed to a harsh environment has a qualified life goal of 60 years. Demonstration of qualified life by test or test and analysis is provided by the Combined License applicant, to address applicable aging effects. For critical components susceptible to aging, a qualified life is established that includes the effects of the total integrated radiation dose experienced at their respective locations within the plant. When a 60-year qualified life is not achievable, a shorter qualified life is established, and a replacement program is implemented.

For equipment located in a mild environment, a design life goal is established by using known significant aging mechanisms and reliability data.

Equipment qualification takes into account the most severe environmental conditions resulting from the design basis high-energy line break. Included in these conditions are the short-term peak transient temperature following a main steamline break (MSLB) and a radiation exposure and temperature due to a loss of coolant accident (LOCA) within the reactor containment.

Postulated high-energy line failures as defined in subsection 3.6.2.1.2 are assumed in areas where high-energy lines greater than 1 inch are routed. Essential equipment is protected against the effects of jet impingement (subsection 3.6.2.4.1) and evaluated for spray effects if required (subsection 3.6.2.7).

Active mechanical equipment is qualified for operability as discussed in subsection 3.9.3 and Section 3.10. This operability program, combined with the qualification of the electrical appurtenances (valve operators, solenoids, limit switches), demonstrates qualification under required environmental conditions. Active mechanical equipment is defined as equipment that performs a mechanical motion as part of its safety-related function.

Nonactive mechanical equipment whose only safety function is structural integrity is designed according to ASME Code guidelines. The accident and post-accident environmental effects are considered in the design of such structural components as pump casings and valve bodies.

The environmental qualification program is restricted to evaluating the design of critical nonmetallic subcomponents of active devices in a harsh environment, where failure results in loss of the active component.

In the event of potential flooding/wetting, one of the following criteria is applied for protection of equipment for service in such an environment:

- Equipment will be qualified for submergence due to flooding/wetting.
- Equipment will be protected from wetting due to spray.
- Equipment will be evaluated to show that failure of the equipment due to flooding/wetting is acceptable since its safety-related function is not required or has otherwise been accomplished.

3.11.1.3 Equipment Operability Times

For the AP1000 Class 1E electrical and active mechanical equipment, post-accident operability times are shown in Table 3D.4-2 in Appendix 3D.

Specific information for each device qualified as part of the IEEE 323-1974 qualification program is contained in the appropriate equipment qualification data package.

The active mechanical component is qualified for operability as discussed in Section 3.10, using test, analysis, or a combination of tests and analyses. This operability program, combined with the qualification of the electrical appurtenances (for example, valve operators) discussed in the appropriate equipment qualification data packages, demonstrates qualification.

3.11.1.4 Standard Review Plan Evaluation

A discussion of the Standard Review Plan requirements in regard to environmental qualification of mechanical equipment is provided in subsection 1.9.2.

3.11.2 Qualification Tests and Analysis

3.11.2.1 Environmental Qualification of Electrical Equipment

The AP1000 approach for environmental qualification of Class 1E equipment is outlined in Appendix 3D. This methodology is developed based on the guidelines provided in IEEE 323-1974 (Reference 1), and 344-1987 (Reference 2).

Qualification for equipment in a harsh environment is based on type testing or testing and analysis. Analysis may be used to determine significant aging mechanisms in mild environment applications. Type testing includes thermal and mechanical aging, radiation, and exposure to extremes of environmental, seismic, and vibration effects. Type testing is done with representative samples of the production line equipment according to the sequence indicated in IEEE 323-1974 to the specified service conditions, including margin. The testing takes into account normal and abnormal plant operation and design basis accident and post-design basis accident operations, as required.

When reliable data and proven analytical methods are available, environmental qualification may be based on analysis supported by partial type test data. This method includes justification of the methods, theories, and assumptions used (that is, mathematical or logical proof based on actual

test data) that the equipment meets or exceeds its specified performance requirements when subjected to normal, abnormal, and design basis accident environmental conditions.

Regulatory guides providing guidance for meeting the requirements of 10CFR50, Appendix A, General Design Criteria 1, 4, 23, and 50; Appendix B, Criteria III, XI, and XVII to 10CFR50 and 10CFR50.49, include Regulatory Guide 1.89, Regulatory Guide 1.30, Regulatory Guide 1.63, Regulatory Guide 1.73, Regulatory Guide 1.100, and Regulatory Guide 1.131. The maintenance surveillance program follows the guidance of Regulatory Guide 1.33.

Additional information regarding conformance with each of these regulatory guides is given in Section 1.9.

3.11.2.2 Environmental Qualification of Mechanical Equipment

AP1000 mechanical components identified in Table 3.11-1 are qualified by design to perform their required functions under the appropriate environmental effects of normal, abnormal, accident, and post-accident conditions as required by General Design Criterion 4 and discussed in Appendix 3D. For mild environments, the area conditions do not change as a result of an accident. There are no degrading environmental effects that lead to common mode failure of equipment in mild environments. Mechanical equipment located in harsh environmental zones is designed to perform under the appropriate environmental conditions.

For mechanical equipment, there are two categories of components:

- Active equipment – equipment that performs a mechanical motion as part of its safety-related function.

The program for environmental qualification of active mechanical components is based on a combination of design, test, and analysis of critical sub-components, which is supported by maintenance and surveillance programs.

- Nonactive equipment – equipment whose only safety-related function is structural integrity. Nonactive components are designed for structural integrity according to ASME Code, Section III, as discussed in Section 3.9.

3.11.3 Loss of Ventilation

The abnormal environmental conditions shown on Tables 3D.5-3 and 3D.5-4 reflect anticipated maximum conditions based on loss of normal ventilation systems.

Normal containment heat removal is provided by the nonsafety-related containment air recirculation cooling system. If this system is out of service for an extended period of time, the passive containment cooling system may be initiated to maintain the temperature and pressure below the limits noted. Environmentally qualified equipment located in containment performs its functions under these conditions until the normal containment cooling system is restored.

Equipment areas outside containment and outside the main control room are maintained at normal environmental conditions by nonsafety-related HVAC systems. If these systems are disabled, the

heat generated by this equipment is absorbed by the surrounding concrete with an ambient temperature rise that does not exceed the abnormal condition. Normal HVAC is restored within 72 hours or ventilation is provided as discussed in Section 6.4.

If the normal nonsafety-related main control room HVAC is lost, the heat generated by equipment and people is absorbed by the surrounding concrete. Normal heating, ventilation, and air-conditioning is restored within 72 hours or ventilation is provided as discussed in Section 6.4.

3.11.4 Estimated Radiation and Chemical Environment

The plant-specific estimates of the radiation dose incurred by equipment during normal operation is shown in Table 3D.5-2 and the estimated doses following a loss-of-coolant accident are defined in Table 3D.5-5.

The identified equipment is qualified to perform functions in the radiation environments present during normal and design basis accident conditions. The normal operational exposure is based upon design source terms presented in Chapter 11 and subsection 12.2.1. The equipment and shielding configurations are presented in Section 12.3. Post-accident monitoring, reactor trip and engineered safety features system and component radiation exposures are dependent on the location of the equipment in the plant. Source terms and other accident parameters are presented in subsection 12.2.1 and Chapter 15.

The maximum combined integrated radiation dose inside containment is based on the effects of the normally expected radiation environment (gamma) over the equipment's installed life plus that associated with the most severe design basis event (gamma and beta) during or following which the equipment is required to remain functional.

The chemical environment following a loss of coolant accident is primarily based on the chemistry of the reactor coolant system fluid since there is no caustic containment spray. Sump pH adjustments are considered for certain qualification tests. This is discussed further in Appendix 3D.

3.11.5 Combined License Information Item for Equipment Qualification File

The Combined License applicant is responsible for the maintenance of the equipment qualification file during the equipment selection and procurement phase.

3.11.6 References

1. IEEE 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations."

2. IEEE 344-1987, "IEEE Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations."

Table 3.11-1 (Sheet 1 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
BATTERIES					
IDSA 125V 60 Cell Battery 1A	IDSA DB 1A	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSA 125V 60 Cell Battery 1B	IDSA DB 1B	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSB 125V 60 Cell Battery 1A	IDSB DB 1A	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSB 125V 60 Cell Battery 1B	IDSB DB 1B	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSB 125V 60 Cell Battery 2A	IDSB DB 2A	2	RT ESF PAMS	5 min 24 hr 72 hr	E
IDSB 125V 60 Cell Battery 2B	IDSB DB 2B	2	RT ESF PAMS	5 min 24 hr 72 hr	E
IDSC 125V 60 Cell Battery 1A	IDSC DB 1A	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSC 125V 60 Cell Battery 1B	IDSC DB 1B	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSC 125V 60 Cell Battery 2A	IDSC DB 2A	2	RT ESF PAMS	5 min 24 hr 72 hr	E
IDSC 125V 60 Cell Battery 2B	IDSC DB 2B	2	RT ESF PAMS	5 min 24 hr 72 hr	E
IDSD 125V 60 Cell Battery 1A	IDSD DB 1A	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSD 125V 60 Cell Battery 1B	IDSD DB 1B	2	RT ESF PAMS	5 min 24 hr 24 hr	E
Spare 125V 60 Cell Battery 1A	IDSS DB 1A	2	RT ESF PAMS	5 min 24 hr 72 hr	E
Spare 125V 60 Cell Battery 1B	IDSS DB 1B	2	RT ESF PAMS	5 min 24 hr 72 hr	E

Table 3.11-1 (Sheet 2 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
BATTERY CHARGERS					
IDSA Battery Charger	IDSA DC 1	2	ISOL	24 hr	E
IDSB Battery Charger	IDSB DC 1	2	ISOL	24 hr	E
IDSB Battery Charger 2	IDSB DC 2	2	ISOL	72 hr	E
IDSC Battery Charger 1	IDSC DC 1	2	ISOL	24 hr	E
IDSC Battery Charger 2	IDSC DC 2	2	ISOL	72 hr	E
IDSD Battery Charger	IDSD DC 1	2	ISOL	24 hr	E
Spare Battery Charger	IDSS DC 1	2	ISOL	72 hr	E
DISTRIBUTION PANELS					
IDSA 125 Vdc Dist Panel	IDSA DD 1	2	ESF	24 hr	E
IDSB 125 Vdc Dist Panel	IDSB DD 1	2	ESF	24 hr	E
IDSC 125 Vdc Dist Panel	IDSC DD 1	2	ESF	24 hr	E
IDSD 125 Vdc Dist Panel	IDSD DD 1	2	ESF	24 hr	E
IDSA 120 Vac Dist Panel 1	IDSA EA 1	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSA 120 Vac Dist Panel 2	IDSA EA 2	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSB 120 Vac Dist Panel 1	IDSB EA 1	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSB 120 Vac Dist Panel 2	IDSB EA 2	2	RT ESF PAMS	5 min 24 hr 2 wks	E
IDSB 120 Vac Dist Panel 3	IDSB EA 3	2	PAMS	2 wks	E

Table 3.11-1 (Sheet 3 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
IDSC 120 Vac Dist Panel 1	IDSC EA 1	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSC 120 Vac Dist Panel 2	IDSC EA 2	2	RT ESF PAMS	5 min 24 hr 2 wks	E
IDSC 120 Vac Dist Panel 3	IDSC EA 3	2	PAMS	2 wks	E
IDSD 120 Vac Dist Panel 1	IDSD EA 1	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSD 120 Vac Dist Panel 2	IDSD EA 2	2	RT ESF PAMS	5 min 24 hr 24 hr	E
FUSE PANELS					
IDSA Fuse Panel	IDSA EA 4	2	ISOL	24 hr	E
IDSB Fuse Panel	IDSB EA 4	2	ISOL	24 hr	E
IDSB Fuse Panel	IDSB EA 5	2	ISOL	2 wks	E
IDSB Fuse Panel	IDSB EA 6	2	ISOL	2 wks	E
IDSC Fuse Panel	IDSC EA 4	2	ISOL	24 hr	E
IDSC Fuse Panel	IDSC EA 5	2	ISOL	2 wks	E
IDSC Fuse Panel	IDSC EA 6	2	ISOL	2 wks	E
IDSD Fuse Panel	IDSD EA 4	2	ISOL	24 hr	E
TRANSFER SWITCHES					
IDSA Fused Transfer Switch Box 1	IDSA DF 1	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSB Fused Transfer Switch Box 1	IDSB DF 1	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSB Fused Transfer Switch Box 2	IDSB DF 2	2	RT ESF PAMS	5 min 24 hr 72 hr	E
IDSC Fused Transfer Switch Box 1	IDSC DF 1	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSC Fused Transfer Switch Box 2	IDSC DF 2	2	RT ESF PAMS	5 min 24 hr 72 hr	E
IDSD Fused Transfer Switch Box 1	IDSD DF 1	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSS Fused Transfer Switch Box 1 (Spare)	IDSS DF 1	2	RT ESF	5 min 24 hr	E

Table 3.11-1 (Sheet 4 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	**AP1000 Tag No.**	**Envir. Zone (Note 2)**	**Function (Note 1)**	**Operating Time Required (Note 5)**	**Qualification Program (Note 6)**
			PAMS	72 hr	
IDSS Spare Termination Box	IDSS DF 2	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSS Spare Termination Box	IDSS DF 3	2	RT ESF PAMS	5 min 24 hr 72 hr	E
IDSS Spare Termination Box	IDSS DF 4	2	RT ESF PAMS	5 min 24 hr 72 hr	E
IDSS Spare Termination Box	IDSS DF 5	2	RT ESF PAMS	5 min 24 hr 24 hr	E
MOTOR CONTROL CENTERS					
IDSA 125 Vdc MCC	IDSA DK 1	2	ESF	24 hr	E
IDSB 125 Vdc MCC	IDSB DK 1	2	ESF	24 hr	E
IDSC 125 Vdc MCC	IDSC DK 1	2	ESF	24 hr	E
IDSD 125 Vdc MCC	IDSD DK 1	2	ESF	24 hr	E
SWITCHBOARDS					
IDSA 125 Vdc Switchboard 1	IDSA DS 1	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSB 125 Vdc Switchboard 1	IDSB DS 1	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSB 125 Vdc Switchboard 2	IDSB DS 2	2	RT ESF PAMS	5 min 24 hr 72 hr	E
IDSC 125 Vdc Switchboard 1	IDSC DS 1	2	RT ESF PAMS	5 min 24 hr 24 hr	E
IDSC 125 Vdc Switchboard 2	IDSC DS 2	2	RT ESF PAMS	5 min 24 hr 72 hr	E
IDSD 125 Vdc Switchboard 1	IDSD DS 1	2	RT ESF PAMS	5 min 24 hr 24 hr	E

Table 3.11-1 (Sheet 5 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
TRANSFORMERS					
IDSA Regulating Transformer 1	IDSA DT 1	2	ISOL	24 hr	E
IDSB Regulating Transformer 1	IDSB DT 1	2	ISOL	72 hr	E
			PAMS	2 wks	
IDSC Regulating Transformer 1	IDSC DT 1	2	ISOL	72 hr	E
			PAMS	2 wks	
IDSD Regulating Transformer 1	IDSD DT 1	2	ISOL	24 hr	E
INVERTERS					
IDSA Inverter	IDSA DU 1	2	RT	5 min	E
			ESF	24 hr	
			PAMS	24 hr	
IDSB Inverter 1	IDSB DU 1	2	RT	5 min	E
			ESF	24 hr	
			PAMS	24 hr	
IDSB Inverter 2	IDSB DU 2	2	RT	5 min	E
			ESF	24 hr	
			PAMS	2 wks	
IDSC Inverter 1	IDSC DU 1	2	RT	5 min	E
			ESF	24 hr	
			PAMS	24 hr	
IDSC Inverter 2	IDSC DU 2	2	RT	5 min	E
			ESF	24 hr	
			PAMS	2 wks	
IDSD Inverter	IDSD DU 1	2	RT	5 min	E
			ESF	24 hr	
			PAMS	24 hr	
SWITCHGEAR					
RCP 1A 6900V Switchgear 31	ECS ES 31	2	ESF	5 min	E
			PAMS	2 wks	
RCP 1A 6900V Switchgear 32	ECS ES 32	2	ESF	5 min	E
			PAMS	2 wks	
RCP 2A 6900V Switchgear 51	ECS ES 51	2	ESF	5 min	E
			PAMS	2 wks	
RCP 2A 6900V Switchgear 52	ECS ES 52	2	ESF	5 min	E
			PAMS	2 wks	
RCP 1B 6900V Switchgear 41	ECS ES 41	2	ESF	5 min	E
			PAMS	2 wks	
RCP 1B 6900V Switchgear 42	ECS ES 42	2	ESF	5 min	E
			PAMS	2 wks	
RCP 2B 6900V Switchgear 61	ECS ES 61	2	ESF	5 min	E
			PAMS	2 wks	
RCP 2B 6900V Switchgear 62	ECS ES 62	2	ESF	5 min	E
			PAMS	2 wks	

Table 3.11-1 (Sheet 6 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Reactor Trip Switchgear	PMS JD RTSA01	4	RT PAMS	5 min 2 wks	E
Reactor Trip Switchgear	PMS JD RTSA02	4	RT PAMS	5 min 2 wks	E
Reactor Trip Switchgear	PMS JD RTSB01	4	RT PAMS	5 min 2 wks	E
Reactor Trip Switchgear	PMS JD RTSB02	4	RT PAMS	5 min 2 wks	E
Reactor Trip Switchgear	PMS JD RTSC01	4	RT PAMS	5 min 2 wks	E
Reactor Trip Switchgear	PMS JD RTSC02	4	RT PAMS	5 min 2 wks	E
Reactor Trip Switchgear	PMS JD RTSD01	4	RT PAMS	5 min 2 wks	E
Reactor Trip Switchgear	PMS JD RTSD02	4	RT PAMS	5 min 2 wks	E
LEVEL SWITCHES					
Core Makeup Tank A Narrow Range Upper Level	PXS JE LS 011A	1	ESF PAMS	24 hr 4 mos	E *
Core Makeup Tank A Narrow Range Upper Level	PXS JE LS 011B	1	ESF PAMS	24 hr 4 mos	E *
Core Makeup Tank A Narrow Range Upper Level	PXS JE LS 011C	1	ESF PAMS	24 hr 4 mos	E *
Core Makeup Tank A Narrow Range Upper Level	PXS JE LS 011D	1	ESF PAMS	24 hr 4 mos	E *
Core Makeup Tank B Narrow Range Upper Level	PXS JE LS 012A	1	ESF PAMS	24 hr 4 mos	E *
Core Makeup Tank B Narrow Range Upper Level	PXS JE LS 012B	1	ESF PAMS	24 hr 4 mos	E *
Core Makeup Tank B Narrow Range Upper Level	PXS JE LS 012C	1	ESF PAMS	24 hr 4 mos	E *
Core Makeup Tank B Narrow Range Upper Level	PXS JE LS 012D	1	ESF PAMS	24 hr 4 mos	E *

Table 3.11-1 (Sheet 7 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Core Makeup Tank A Narrow Range Lower Level	PXS JE LS 013A	1	ESF PAMS	24 hr 4 mos	E *
Core Makeup Tank A Narrow Range Lower Level	PXS JE LS 013B	1	ESF PAMS	24 hr 4 mos	E *
Core Makeup Tank A Narrow Range Lower Level	PXS JE LS 013C	1	ESF PAMS	24 hr 4 mos	E *
Core Makeup Tank A Narrow Range Lower Level	PXS JE LS 013D	1	ESF PAMS	24 hr 4 mos	E *
Core Makeup Tank B Narrow Range Lower Level	PXS JE LS 014A	1	ESF PAMS	24 hr 4 mos	E *
Core Makeup Tank B Narrow Range Lower Level	PXS JE LS 014B	1	ESF PAMS	24 hr 4 mos	E *
Core Makeup Tank B Narrow Range Lower Level	PXS JE LS 014C	1	ESF PAMS	24 hr 4 mos	E *
Core Makeup Tank B Narrow Range Lower Level	PXS JE LS 014D	1	ESF PAMS	24 hr 4 mos	E *
Accumulator Tank A Pressure	PXS JE LT 027	1	PAMS	4 mos	E * +
Accumulator Tank B Pressure	PXS JE LT 028	1	PAMS	4 mos	E * +
Accumulator Tank A Pressure	PXS JE LT 029	1	PAMS	4 mos	E * +
Accumulator Tank B Pressure	PXS JE LT 030	1	PAMS	4 mos	E * +

Table 3.11-1 (Sheet 8 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Containment Floodup Level	PXS JE LS 050	1	PAMS	4 mos	E *
Containment Floodup Level	PXS JE LS 051	1	PAMS	4 mos	E *
Containment Floodup Level	PXS JE LS 052	1	PAMS	4 mos	E *
NEUTRON DETECTORS					
Source Range Neutron Detector	RXS JE NE 001A	1	RT ESF	Note 3 Note 3	E *
Source Range Neutron Detector	RXS JE NE 001B	1	RT ESF	Note 3 Note 3	E *
Source Range Neutron Detector	RXS JE NE 001C	1	RT ESF	Note 3 Note 3	E *
Source Range Neutron Detector	RXS JE NE 001D	1	RT ESF	Note 3 Note 3	E *
Intermediate Range Neutron Detector	RXS JE NE 002A	1	RT PAMS	Note 3 4 mos	E *
Intermediate Range Neutron Detector	RXS JE NE 002B	1	RT PAMS	Note 3 4 mos	E *
Intermediate Range Neutron Detector	RXS JE NE 002C	1	RT PAMS	Note 3 4 mos	E *
Intermediate Range Neutron Detector	RXS JE NE 002D	1	RT PAMS	Note 3 4 mos	E *
Power Range Neutron Detector (Lower)	RXS JE NE 003A	1	RT	5 min	E *
Power Range Neutron Detector (Lower)	RXS JE NE 003B	1	RT	5 min	E *
Power Range Neutron Detector (Lower)	RXS JE NE 003C	1	RT	5 min	E *
Power Range Neutron Detector (Lower)	RXS JE NE 003D	1	RT	5 min	E *
Power Range Neutron Detector (Upper)	RXS JE NE 004A	1	RT	5 min	E *
Power Range Neutron Detector (Upper)	RXS JE NE 004B	1	RT	5 min	E *
Power Range Neutron Detector (Upper)	RXS JE NE 004C	1	RT	5 min	E *
Power Range Neutron Detector (Upper)	RXS JE NE 004D	1	RT	5 min	E *

Table 3.11-1 (Sheet 9 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
RADIATION MONITORS					
Blowdown Discharge Radiation	BDS JE RE 010	8	PAMS	2 wks	E +
Blowdown Brine Radiation	BDS JE RE 011	8	PAMS	2 wks	E +
Containment High Range Area Monitor	PXS JE RE 160	1	ESF PAMS	24 hr 4 mos	E *
Containment High Range Area Monitor	PXS JE RE 161	1	ESF PAMS	24 hr 4 mos	E *
Containment High Range Area Monitor	PXS JE RE 162	1	ESF PAMS	24 hr 4 mos	E *
Containment High Range Area Monitor	PXS JE RE 163	1	ESF PAMS	24 hr 4 mos	E *
Main Steamline Radiation	SGS JE RE 026	5	PAMS	2 wks	E +
Main Steamline Radiation	SGS JE RE 027	5	PAMS	2 wks	E +
Turbine Island Vent Radiation	TDS JE RE 001	8	PAMS	2 wks	E +
Control Room Supply Air Radiation Monitor	VBS JE RE 001A	3	ESF PAMS	24 hr 2 wks	E
Control Room Supply Air Radiation Monitor	VBS JE RE 001B	3	ESF PAMS	24 hr 2 wks	E
Plant Vent Radiation Mid Range	VFS JE RE 104A	7	PAMS	2 wks	E +
Plant Vent Radiation High Range	VFS JE RE 104B	7	PAMS	2 wks	E +
RESISTANCE TEMPERATURE DETECTORS					
PRHR HX Outlet Temperature	RCS JE TE 161	1	PAMS	4 mos	E *
RCS Cold Leg 1A Narrow Range Temperature	RCS JE TE 121A	1	RT ESF	5 min 5 min	E *
RCS Cold Leg 1A Narrow Range Temperature	RCS JE TE 121D	1	RT ESF	5 min 5 min	E *
RCS Cold Leg 1B Narrow Range Temperature	RCS JE TE 121B	1	RT ESF	5 min 5 min	E *
RCS Cold Leg 1B Narrow Range Temperature	RCS JE TE 121C	1	RT ESF	5 min 5 min	E *
RCS Cold Leg 2A Narrow Range Temperature	RCS JE TE 122B	1	RT ESF	5 min 5 min	E *
RCS Cold Leg 2A Narrow Range Temperature	RCS JE TE 122C	1	RT ESF	5 min 5 min	E *
RCS Cold Leg 2B Narrow Range Temperature	RCS JE TE 122A	1	RT ESF	5 min 5 min	E *
RCS Cold Leg 2B Narrow Range Temperature	RCS JE TE 122D	1	RT ESF	5 min 5 min	E *
RCS Hot Leg 1 Narrow Range Temperature	RCS JE TE 131A	1	RT ESF	5 min 5 min	E *
RCS Hot Leg 1 Narrow Range Temperature	RCS JE TE 131C	1	RT ESF	5 min 5 min	E *

Table 3.11-1 (Sheet 10 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
RCS Hot Leg 1 Narrow Range Temperature	RCS JE TE 132A	1	RT ESF	5 min 5 min	E *
RCS Hot Leg 1 Narrow Range Temperature	RCS JE TE 132C	1	RT ESF	5 min 5 min	E *
RCS Hot Leg 1 Narrow Range Temperature	RCS JE TE 133C	1	RT ESF	5 min 5 min	E *
RCS Hot Leg 1 Narrow Range Temperature	RCS JE TE 133A	1	RT ESF	5 min 5 min	E *
RCS Hot Leg 2 Narrow Range Temperature	RCS JE TE 131B	1	RT ESF	5 min 5 min	E *
RCS Hot Leg 2 Narrow Range Temperature	RCS JE TE 131D	1	RT ESF	5 min 5 min	E *
RCS Hot Leg 2 Narrow Range Temperature	RCS JE TE 132B	1	RT ESF	5 min 5 min	E *
RCS Hot Leg 2 Narrow Range Temperature	RCS JE TE 132D	1	RT ESF	5 min 5 min	E *
RCS Hot Leg 2 Narrow Range Temperature	RCS JE TE 133B	1	RT ESF	5 min 5 min	E *
RCS Hot Leg 2 Narrow Range Temperature	RCS JE TE 133D	1	RT ESF	5 min 5 min	E *
RCS Cold Leg 1A Wide Range Temperature	RCS JE TE 125A	1	PAMS	4 mos	E *
RCS Cold Leg 1B Wide Range Temperature	RCS JE TE 125C	1	PAMS	4 mos	E *
RCS Cold Leg 2A Wide Range Temperature	RCS JE TE 125B	1	PAMS	4 mos	E *
RCS Cold Leg 2B Wide Range Temperature	RCS JE TE 125D	1	PAMS	4 mos	E *
RCS Hot Leg 1 Wide Range Temperature	RCS JE TE 135A	1	PAMS	4 mos	E *
RCS Hot Leg 2 Wide Range Temperature	RCS JE TE 135B	1	PAMS	4 mos	E *
PZR Reference Leg Level Temperature	RCS JE TE 193A	1	RT ESF PAMS	5 min 5 min 4 mos	E *
PZR Reference Leg Level Temperature	RCS JE TE 193B	1	RT ESF PAMS	5 min 5 min 4 mos	E *
PZR Reference Leg Level Temperature	RCS JE TE 193C	1	RT ESF PAMS	5 min 5 min 4 mos	E *
PZR Reference Leg Level Temperature	RCS JE TE 193D	1	RT ESF PAMS	5 min 5 min 4 mos	E *

Table 3.11-1 (Sheet 11 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Containment Temperature	VCS JE TE 053A	1	PAMS	4 mos	E * +
Containment Temperature	VCS JE TE 053B	1	PAMS	4 mos	E * +
SPEED SENSORS					
RCP 1A Pump Speed	RCS JE ST 281	1	RT	Note 3	E
RCP 1B Pump Speed	RCS JE ST 282	1	RT	Note 3	E
RCP 2A Pump Speed	RCS JE ST 283	1	RT	Note 3	E
RCP 2B Pump Speed	RCS JE ST 284	1	RT	Note 3	E
THERMOCOUPLES					
Incore Thermocouples	IIS JE TE 001 through IIS JE TE 042	1	PAMS	1 yr	E *
RCP 1A Bearing Water Temperature	RCS JE TE 211A	1	RT	Note 3	E
RCP 1A Bearing Water Temperature	RCS JE TE 211B	1	RT	Note 3	E
RCP 1A Bearing Water Temperature	RCS JE TE 211C	1	RT	Note 3	E
RCP 1A Bearing Water Temperature	RCS JE TE 211D	1	RT	Note 3	E
RCP 1B Bearing Water Temperature	RCS JE TE 212A	1	RT	Note 3	E
RCP 1B Bearing Water Temperature	RCS JE TE 212B	1	RT	Note 3	E
RCP 1B Bearing Water Temperature	RCS JE TE 212C	1	RT	Note 3	E
RCP 1B Bearing Water Temperature	RCS JE TE 212D	1	RT	Note 3	E
RCP 2A Bearing Water Temperature	RCS JE TE 213A	1	RT	Note 3	E
RCP 2A Bearing Water Temperature	RCS JE TE 213B	1	RT	Note 3	E
RCP 2A Bearing Water Temperature	RCS JE TE 213C	1	RT	Note 3	E
RCP 2A Bearing Water Temperature	RCS JE TE 213D	1	RT	Note 3	E
RCP 2B Bearing Water Temperature	RCS JE TE 214A	1	RT	Note 3	E
RCP 2B Bearing Water Temperature	RCS JE TE 214B	1	RT	Note 3	E
RCP 2B Bearing Water Temperature	RCS JE TE 214C	1	RT	Note 3	E
RCP 2B Bearing Water Temperature	RCS JE TE 214D	1	RT	Note 3	E

Table 3.11-1 (Sheet 12 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
TRANSMITTERS					
PCS Water Delivery Flow	PCS JE FT 001	9	PAMS	2 wks	E
PCS Water Delivery Flow	PCS JE FT 002	9	PAMS	2 wks	E
PCS Water Delivery Flow	PCS JE FT 003	9	PAMS	2 wks	E
PCS Water Delivery Flow	PCS JE FT 004	9	PAMS	2 wks	E
PCS Storage Tank Water Level	PCS JE LT 010	9	PAMS	2 wks	E
PCS Storage Tank Water Level	PCS JE LT 011	9	PAMS	2 wks	E
PRHR HX Flow	PXS JE FT 049A	1	PAMS	4 mos	E *
PRHR HX Flow	PXS JE FT 049B	1	PAMS	4 mos	E *
RCS Hot Leg 1 Flow	RCS JE FT 101A	1	RT	Note 3	E
RCS Hot Leg 1 Flow	RCS JE FT 101B	1	RT	Note 3	E
RCS Hot Leg 1 Flow	RCS JE FT 101C	1	RT	Note 3	E
RCS Hot Leg 1 Flow	RCS JE FT 101D	1	RT	Note 3	E
RCS Hot Leg 2 Flow	RCS JE FT 102A	1	RT	Note 3	E
RCS Hot Leg 2 Flow	RCS JE FT 102B	1	RT	Note 3	E
RCS Hot Leg 2 Flow	RCS JE FT 102C	1	RT	Note 3	E
RCS Hot Leg 2 Flow	RCS JE FT 102D	1	RT	Note 3	E
SG1 Startup Feedwater Flow	SGS JE FT 055A	2	ESF PAMS	5 min 2 wks	E
SG1 Startup Feedwater Flow	SGS JE FT 055B	2	ESF PAMS	5 min 2 wks	E
SG2 Startup Feedwater Flow	SGS JE FT 056A	2	ESF PAMS	5 min 2 wks	E
SG2 Startup Feedwater Flow	SGS JE FT 056B	2	ESF PAMS	5 min 2 wks	E
Plant Vent Flow	VFS JE FT 101	7	PAMS	2 wks	E +

Table 3.11-1 (Sheet 13 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
IRWST Level	PXS JE LT 045	1	PAMS ESF	4 mos 24 hr	E *
IRWST Level	PXS JE LT 046	1	PAMS ESF	4 mos 24 hr	E *
IRWST Level	PXS JE LT 047	1	PAMS ESF	4 mos 24 hr	E *
IRWST Level	PXS JE LT 048	1	PAMS ESF	4 mos 24 hr	E *
RCS Hot Leg Water Level	RCS JE LT 160A	1	PAMS	4 mos	E *
RCS Hot Leg Water Level	RCS JE LT 160B	1	PAMS	4 mos	E *
PZR Level	RCS JE LT 195A	1	RT ESF PAMS	5 min 5 min 4 mos	E *
PZR Level	RCS JE LT 195B	1	RT ESF PAMS	5 min 5 min 4 mos	E *
PZR Level	RCS JE LT 195C	1	RT ESF PAMS	5 min 5 min 4 mos	E *
PZR Level	RCS JE LT 195D	1	RT ESF PAMS	5 min 5 min 4 mos	E *
SG1 Narrow Range Level	SGS JE LT 001	1	RT ESF PAMS	5 min 5 min 4 mos	E *
SG1 Narrow Range Level	SGS JE LT 002	1	RT ESF PAMS	5 min 5 min 4 mos	E *
SG1 Narrow Range Level	SGS JE LT 003	1	RT ESF PAMS	5 min 5 min 4 mos	E *
SG1 Narrow Range Level	SGS JE LT 004	1	RT ESF PAMS	5 min 5 min 4 mos	E *
SG2 Narrow Range Level	SGS JE LT 005	1	RT ESF PAMS	5 min 5 min 4 mos	E *
SG2 Narrow Range Level	SGS JE LT 006	1	RT ESF PAMS	5 min 5 min 4 mos	E *

Table 3.11-1 (Sheet 14 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
SG2 Narrow Range Level	SGS JE LT 007	1	RT ESF PAMS	5 min 5 min 4 mos	E *
SG2 Narrow Range Level	SGS JE LT 008	1	RT ESF PAMS	5 min 5 min 4 mos	E *
SG1 Wide Range Level	SGS JE LT 011	1	ESF PAMS	5 min 4 mos	E *
SG1 Wide Range Level	SGS JE LT 012	1	ESF PAMS	5 min 4 mos	E *
SG1 Wide Range Level	SGS JE LT 015	1	ESF PAMS	5 min 4 mos	E * E *
SG1 Wide Range Level	SGS JE LT 016	1	ESF PAMS	5 min 4 mos	E * E *
SG2 Wide Range Level	SGS JE LT 013	1	ESF PAMS	5 min 4 mos	E *
SG2 Wide Range Level	SGS JE LT 014	1	ESF PAMS	5 min 4 mos	E *
SG2 Wide Range Level	SGS JE LT 017	1	ESF PAMS	5 min 4 mos	E *
SG2 Wide Range Level	SGS JE LT 018	1	ESF PAMS	5 min 4 mos	E *
Spent Fuel Pool Level	SFS JE LT 019A	6	PAMS	2 wks	E
Spent Fuel Pool Level	SFS JE LT 019B	7	PAMS	2 wks	E
Spent Fuel Pool Level	SFS JE LT 019C	6	PAMS	2 wks	E
Air Storage Tank Pressure - A	VES JE PT 001A	7	PAMS	2 wks	E+
Air Storage Tank Pressure - B	VES JE PT 001B	7	PAMS	2 wks	E+
Containment Pressure Normal Range	PCS JE PT 005	1	ESF PAMS	5 min 4 mos	E *
Containment Pressure Normal Range	PCS JE PT 006	1	ESF PAMS	5 min 4 mos	E *
Containment Pressure Normal Range	PCS JE PT 007	1	ESF PAMS	5 min 4 mos	E *
Containment Pressure Normal Range	PCS JE PT 008	1	ESF PAMS	5 min 4 mos	E *
Containment Pressure Extended Range	PCS JE PT 012	1	PAMS	4 mos	E *
Containment Pressure Extended Range	PCS JE PT 013	1	PAMS	4 mos	E *
Containment Pressure Extended Range	PCS JE PT 014	1	PAMS	4 mos	E *

Table 3.11-1 (Sheet 15 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
RCS Wide Range Pressure	RCS JE PT 140A	1	PAMS ESF	4 mos 5 min	E *
RCS Wide Range Pressure	RCS JE PT 140B	1	PAMS ESF	4 mos 5 min	E *
RCS Wide Range Pressure	RCS JE PT 140C	1	PAMS ESF	4 mos 5 min	E *
RCS Wide Range Pressure	RCS JE PT 140D	1	PAMS ESF	4 mos 5 min	E *
PZR Pressure	RCS JE PT 191A	1	RT ESF PAMS	5 min 5 min 4 mos	E *
PZR Pressure	RCS JE PT 191B	1	RT ESF PAMS	5 min 5 min 4 mos	E *
PZR Pressure	RCS JE PT 191C	1	RT ESF PAMS	5 min 5 min 4 mos	E *
PZR Pressure	RCS JE PT 191D	1	RT ESF PAMS	5 min 5 min 4 mos	E *
Main Steamline SG1 Pressure	SGS JE PT 030	1	ESF PAMS	5 min 2 wks	E *
Main Steamline SG1 Pressure	SGS JE PT 031	2	ESF PAMS	5 min 2 wks	E
Main Steamline SG1 Pressure	SGS JE PT 032	1	ESF PAMS	5 min 2 wks	E *
Main Steamline SG1 Pressure	SGS JE PT 033	2	ESF PAMS	5 min 2 wks	E
Main Steamline SG2 Pressure	SGS JE PT 034	1	ESF PAMS	5 min 2 wks	E *
Main Steamline SG2 Pressure	SGS JE PT 035	2	ESF PAMS	5 min 2 wks	E
Main Steamline SG2 Pressure	SGS JE PT 036	1	ESF PAMS	5 min 2 wks	E *
Main Steamline SG2 Pressure	SGS JE PT 037	2	ESF PAMS	5 min 2 wks	E
Main Control Room Differential Pressure	VES JE PT 004A	3	ESF	2 wks	E
Main Control Room Differential Pressure	VES JE PT 004B	3	ESF	2 wks	E

Table 3.11-1 (Sheet 16 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
PROTECTION AND SAFETY MONITORING SYSTEMS					
Protection and Safety Monitoring System Cabinets	Multiple (Note 7)	2	RT ESF PAMS	5 min 24 hr 2 wks	E
MAIN CONTROL ROOM					
Operator Workstation A	N/A	3	RT ESF PAMS	5 min 24 hr 2 wks	E
Operator Workstation B	N/A	3	RT ESF PAMS	5 min 24 hr 2 wks	E
Supervisor Workstation	N/A	3	RT ESF PAMS	5 min 24 hr 2 wks	E
Switch Station (Including Switches)	N/A	3	RT ESF	5 min 24 hr	E
QDPS Thermocouple Reference Panel 1	PMS-JW-003B	1	PAMS	1 yr	E *
QDPS Thermocouple Reference Panel 2	PMS-JW-003C	1	PAMS	1 yr	E *
MCR/RSW Transfer Switch Panel A	PMS-JW-004A	2	RT ESF	5 min 24 hr	E
MCR/RSW Transfer Switch Panel B	PMS-JW-004B	2	RT ESF	5 min 24 hr	E
MCR/RSW Transfer Switch Panel C	PMS-JW-004C	2	RT ESF	5 min 24 hr	E
MCR/RSW Transfer Switch Panel D	PMS-JW-004D	2	RT ESF	5 min 24 hr	E
Source Range Neutron Flux Preamplifier Panel A	PMS-JW-005A	2	RT, ESF	Note 3	E
Source Range Neutron Flux Preamplifier Panel B	PMS-JW-005B	2	RT, ESF	Note 3	E
Source Range Neutron Flux Preamplifier Panel C	PMS-JW-005C	2	RT, ESF	Note 3	E
Source Range Neutron Flux Preamplifier Panel D	PMS-JW-005D	2	RT, ESF	Note 3	E

Table 3.11-1 (Sheet 17 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Intermediate Range Neutron Flux Preamplifier Panel A	PMS-JW-006A	2	RT PAMS	Note 3 4 mos	E
Intermediate Range Neutron Flux Preamplifier Panel B	PMS-JW-006B	2	RT PAMS	Note 3 4 mos	E
Intermediate Range Neutron Flux Preamplifier Panel C	PMS-JW-006C	2	RT PAMS	Note 3 4 mos	E
Intermediate Range Neutron Flux Preamplifier Panel D	PMS-JW-006D	2	RT PAMS	Note 3 4 mos	E
Power Range Neutron Flux High Voltage Distribution Box A	PMS-JW-007A	2	RT	5 min	E
Power Range Neutron Flux High Voltage Distribution Box B	PMS-JW-007B	2	RT	5 min	E
Power Range Neutron Flux High Voltage Distribution Box C	PMS-JW-007C	2	RT	5 min	E
Power Range Neutron Flux High Voltage Distribution Box D	PMS-JW-007D	2	RT	5 min	E
QDPS MCR Display Unit	PMS JY 001B	3	PAMS	2 wks	E
QDPS MCR Display Unit	PMS JY 001C	3	PAMS	2 wks	E
PENETRATIONS					
Penetrations (Mechanical)	See Table 6.2.3-1				M *
Penetrations (Electrical)	See Figure 3.8.2-4				E *

Table 3.11-1 (Sheet 18 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
ACTIVE VALVES					
Containment Isolation - Air Out	CAS PL V014	2	ESF	5 min	M S
Solenoid Valve	CAS PL V014-S	2	ESF	5 min	E
Limit Switch	CAS PL V014-L	2	PAMS	2 wks	E
Containment Isolation - Air In	CAS PL V015	1	ESF	5 min	M *
Containment Isolation - Inlet	CCS PL V200	2	ESF	5 min	M S
Limit Switch	CCS PL V200-L	2	PAMS	2 wks	E
Motor Operator	CCS PL V200-M	2	ESF	5 min	E
Containment Isolation - Inlet	CCS PL V201	1	ESF	5 min	M *
Containment Isolation - Outlet	CCS PL V207	1	ESF	5 min	M *
Limit Switch	CCS PL V207-L	1	PAMS	1 yr	E *
Motor Operator	CCS PL V207-M	1	ESF	5 min	E *
Containment Isolation - Outlet	CCS PL V208	2	ESF	5 min	M S
Limit Switch	CCS PL V208-L	2	PAMS	2 wks	E
Motor Operator	CCS PL V208-M	2	ESF	5 min	E
RCS Purification Stop Valve	CVS PL V001	1	ESF	5 min	M *
Limit Switch	CVS PL V001-L	1	PAMS	1 yr	E *
Motor Operator	CVS PL V001-M	1	ESF	5 min	E *
RCS Purification Stop Valve	CVS PL V002	1	ESF	5 min	M *
Limit Switch	CVS PL V002-L	1	PAMS	1 yr	E *
Motor Operator	CVS PL V002-M	1	ESF	5 min	E *
RCS Letdown Stop Valve	CVS PL V003	1	ESF	5 min	M *
Limit Switch	CVS PL V003-L	1	PAMS	1 yr	E *
Motor Operator	CVS PL V003-M	1	ESF	5 min	E *
Demineralizer Flush Line Relief	CVS PL V042	1	ESF	24 hr	M
WLS Letdown IRC Isolation	CVS PL V045	1	ESF	5 min	M *
Limit Switch	CVS PL V045-L	1	PAMS	1 yr	E *
Solenoid Valve	CVS PL V045-S	1	ESF	5 min	E *
Letdown Flow ORC Isolation	CVS PL V047	7	ESF	5 min	M S
Limit Switch	CVS PL V047-L	7	PAMS	2 wks	E
Solenoid Valve	CVS PL V047-S	7	ESF	5 min	E

Table 3.11-1 (Sheet 19 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
RCS Purification Check Valve	CVS PL V080	1	ESF	5 min	M *
RCS Purification Stop Valve	CVS PL V081	1	ESF	5 min	
Limit Switch	CVS PL V081-L	1	PAMS	1 yr	E * +
Solenoid Valve	CVS PL V081-S	1	ESF	5 min	E *
RCS Purification Check Valve	CVS PL V082	1	ESF	5 min	M *
Auxiliary PZR Spray Isolation	CVS PL V084	1	ESF	5 min	M *
Limit Switch	CVS PL V084-L	1	PAMS	1 yr	E * +
Solenoid Valve	CVS PL V084-S	1	ESF	5 min	E *
Auxiliary PZR Spray Isolation	CVS PL V085	1	ESF	5 min	M *
Makeup Line Containment Isolation	CVS PL V090	7	ESF	5 min	M S
Limit Switch	CVS PL V090-L	7	PAMS	2 wks	E
Motor Operator	CVS PL V090-M	7	ESF	5 min	E
Makeup Line Containment Isolation	CVS PL V091	1	ESF	5 min	M *
Limit Switch	CVS PL V091-L	1	PAMS	1 yr	E *
Motor Operator	CVS PL V091-M	1	ESF	5 min	E *
Hydrogen Addition Containment Isolation	CVS PL V092	10	ESF	5 min	M *
Limit Switch	CVS PL V092-L	10	PAMS	2 wks	E *
Solenoid Valve	CVS PL V092-S	10	ESF	5 min	E *
Hydrogen Addition Containment Isolation	CVS PL V094	1	ESF	5 min	M *
Makeup Containment Isolation	CVS PL V100	1	ESF	24 hrs	M *
Demineralizer Water System Isolation	CVS PL V136A	6	ESF	5 min	M
Limit Switch	CVS PL V136A-L	6	PAMS	2 wks	E +
Solenoid Valve	CVS PL V136A-S	6	ESF	5 min	E
Demineralized Water System Isolation	CVS PL V136B	6	ESF	5 min	M
Limit Switch	CVS PL V136B-L	6	PAMS	2 wks	E +
Solenoid Valve	CVS PL V136B-S	6	ESF	5 min	E
Main to Startup Feed Header (Limit Switch)	FWS PL V097	8	PAMS	2 wks	E +

Table 3.11-1 (Sheet 20 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Turbine Bypass Control Valve (Limit Switch)	MSS PL V001L	8	PAMS	2 wks	E +
Turbine Bypass Control Valve (Limit Switch)	MSS PL V002L	8	PAMS	2 wks	E +
Turbine Bypass Control Valve (Limit Switch)	MSS PL V003L	8	PAMS	2 wks	E +
Turbine Bypass Control Valve (Limit Switch)	MSS PL V004L	8	PAMS	2 wks	E +
Turbine Bypass Control Valve (Limit Switch)	MSS PL V005L	8	PAMS	2 wks	E +
Turbine Bypass Control Valve (Limit Switch)	MSS PL V006L	8	PAMS	2 wks	E +
PCCWST Isolation Valve	PCS PL V001A	9	ESF	5 min	M S
Limit Switch	PCS PL V001A-L	9	PAMS	2 wks	E +
Solenoid Valve	PCS PL V001A-S	9	ESF	5 min	E
PCCWST Isolation Valve	PCS PL V001B	9	ESF	5 min	M S
Limit Switch	PCS PL V001B-L	9	PAMS	2 wks	E +
Solenoid Valve	PCS PL V001B-S	9	ESF	5 min	E
PCCWST Isolation Valve	PCS PL V001C	9	ESF	5 min	M S
Limit Switch	PCS PL V001C-L	9	PAMS	2 wks	E
Motor Operator	PCS PL V001C-M	9	ESF	5 min	E
PCCWST Isolation Valve	PCS PL V002A	9	ESF	5 min	M S
Limit Switch	PCS PL V002A-L	9	PAMS	2 wks	E
Motor Operator	PCS PL V002A-M	9	ESF	5 min	E
PCCWST Isolation Valve	PCS PL V002B	9	ESF	5 min	M S
Limit Switch	PCS PL V002B-L	9	PAMS	2 wks	E
Motor Operator	PCS PL V002B-M	9	ESF	5 min	E
PCCWST Isolation Valve	PCS PL V002C	9	ESF	5 min	M S
Limit Switch	PCS PL V002C-L	9	PAMS	2 wks	E
Motor Operator	PCS PL V002C-M	9	ESF	5 min	E
PCCWST Fire Protection Isolation	PCS PL V005	10	ESF	72 hrs	M *
PCCWST Emergency Spent Fuel Pool Makeup Isolation	PCS-PL-V009	9	ESF	2 wks	M *
Water Bucket Makeup Line Drain Valve	PCS-PL-V015	10	ESF	2 wks	M *
Water Bucket Makeup Line Isolation Valve	PCS-PL-V020	10	ESF	2 wks	M *
PCS Recirculation Isolation	PCS PL V023	10	ESF	72 hrs	M *

Table 3.11-1 (Sheet 21 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
PCCWST Long-Term Makeup Check Valve	PCS-PL-V039	10	ESF	2 wks	M *
PCCWST Long Term Makeup Isolation Drain Valve	PCS-PL-V042	10	ESF	2 wks	M *
PCCWST Long Term Makeup Isolation Valve	PCS-PL-V044	10	ESF	2 wks	M *
Emergency Makeup to the Spent Fuel Pool Isolation Valve	PCS-PL-V045	6	ESF	2 wks	M *
PCCWST Recirculation Return Isolation Valve	PCS-PL-V046	10	ESF	2 wks	M *
Emergency Makeup to the Spent Fuel Pool Drain Isolation Valve	PCS-PL-V049	6	ESF	2 wks	M *
Spent Fuel Pool Long Term Makeup Isolation Valve	PCS-PL-V050	10	ESF	2 wks	M *
Spent Fuel Pool Emergency Makeup Lower Isolation Valve	PCS-PL-V051	6	ESF	2 wks	M *
Containment Isolation - Air Sample Line	PSS PL V008	1	ESF	4 mos	M *
Limit Switch	PSS PL V008-L	1	PAMS	1 yr	E *
Solenoid Operator	PSS PL V008-S	1	ESF	5 min	E *
Containment Isolation - Liquid Sample Line	PSS PL V010A	1	ESF	4 mos	M *
Limit Switch	PSS PL V010A-L	1	PAMS	1 yr	E *
Solenoid Operator	PSS PL V010A-S	1	ESF	5 min	E *
Containment Isolation - Liquid Sample Line	PSS PL V010B	1	ESF	4 mos	M *
Limit Switch	PSS PL V010B-L	1	PAMS	1 yr	E *
Solenoid Operator	PSS PL V010B-S	1	ESF	5 min	E *
Containment Isolation - Liquid Sample Line	PSS PL V011	6	ESF	2 wks	M S
Limit Switch	PSS PL V011-L	6	PAMS	2 wks	E
Solenoid Valve	PSS PL V011-S	6	ESF	5 min	E
Containment Isolation - Sample Return Line	PSS PL V023	6	ESF	2 wks	M S
Limit Switch	PSS PL V023-L	6	PAMS	2 wks	E
Solenoid Valve	PSS PL V023-S	6	ESF	5 min	E
Containment Isolation Sample Return	PSS PL V024	1	ESF	4 mos	M *

Table 3.11-1 (Sheet 22 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Containment Isolation - Air Sample Line	PSS PL V046	6	ESF	2 wks	M S
Limit Switch	PSS PL V046-L	6	PAMS	2 wks	E
Solenoid Valve	PSS PL V046-S	6	ESF	2 wks	E
Core Makeup Tank A Cold Leg Inlet Isolation	PXS PL V002A	1	ESF	5 min	M *
Limit Switch	PXS PL V002A-L	1	PAMS	1 yr	E *
Motor Operator	PXS PL V002A-M	1	ESF	5 min	E *
Core Makeup Tank B Cold Leg Inlet Isolation	PXS PL V002B	1	ESF	5 min	M *
Limit Switch	PXS PL V002B-L	1	PAMS	1 yr	E *
Motor Operator	PXS PL V002B-M	1	ESF	5 min	E *
Core Makeup Tank A Discharge Isolation	PXS PL V014A	1	ESF	5 min	M *
Limit Switch	PXS PL V014A-L	1	PAMS	1 yr	E * +
Solenoid Valve	PXS PL V014A-S	1	ESF	5 min	E *
Core Makeup Tank B Discharge Isolation	PXS PL V014B	1	ESF	5 min	M *
Limit Switch	PXS PL V014B-L	1	PAMS	1 yr	E * +
Solenoid Valve	PXS PL V014B-S	1	ESF	5 min	E *
Core Makeup Tank A Discharge Isolation	PXS PL V015A	1	ESF	5 min	M *
Limit Switch	PXS PL V015A-L	1	PAMS	1 yr	E * +
Solenoid Valve	PXS PL V015A-S	1	ESF	5 min	E *
Core Makeup Tank B Discharge Isolation	PXS PL V015B	1	ESF	5 min	M *
Limit Switch	PXS PL V015B-L	1	PAMS	1 yr	E * +
Solenoid Valve	PXS PL V015B-S	1	ESF	5 min	E *
Core Makeup Tank A Discharge	PXS PL V016A	1	ESF	5 min	M *
Core Makeup Tank B Discharge	PXS PL V016B	1	ESF	5 min	M *
Core Makeup Tank A Discharge	PXS PL V017A	1	ESF	5 min	M *
Core Makeup Tank B Discharge	PXS PL V017B	1	ESF	5 min	M *
Accumulator A Discharge	PXS PL V028A	1	ESF	5 min	M *
Accumulator B Discharge	PXS PL V028B	1	ESF	5 min	M *
Accumulator A Discharge	PXS PL V029A	1	ESF	5 min	M *
Accumulator B Discharge	PXS PL V029B	1	ESF	5 min	M *
Nitrogen Supply Outside Containment Isolation	PXS PL V042	2	ESF	5 min	M S
Limit Switch	PXS PL V042-L	2	PAMS	2 wks	E
Solenoid Valve	PXS PL V042-S	2	ESF	5 min	E
IRC Nitrogen Supply Inside Containment Isolation	PXS PL V043	1	ESF	5 min	M *
PRHR HX Inlet Isolation	PXS PL V101	1	ESF	5 min	M *
Limit Switch	PXS PL V101-L	1	PAMS	1 yr	E *
Motor Operator	PXS PL V101-M	1	ESF	5 min	E *
PRHR HX Discharge Isolation	PXS PL V108A	1	ESF	5 min	M *
Limit Switch	PXS PL V108A-L	1	PAMS	1 yr	E * +
Solenoid Valve	PXS PL V108A-S	1	ESF	5 min	E *

Table 3.11-1 (Sheet 23 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
PRHR HX Discharge Isolation	PXS PL V108B	1	ESF	5 min	M *
Limit Switch	PXS PL V108B-L	1	PAMS	1 yr	E * +
Solenoid Valve	PXS PL V108B-S	1	ESF	5 min	E *
Recirc Sump A Isolation	PXS PL V117A	1	ESF	24 hr	M *
Limit Switch	PXS PL V117A-L	1	PAMS	1 yr	E *
Motor Operator	PXS PL V117A-M	1	ESF	24 hr	E *
Recirc Sump B Isolation	PXS PL V117B	1	ESF	24 hr	M *
Limit Switch	PXS PL V117B-L	1	PAMS	1 yr	E *
Motor Operator	PXS PL V117B-M	1	ESF	24 hr	E *
Recirc Sump A Isolation	PXS PL V118A	1	ESF	24 hr	M *
Limit Switch	PXS PL V118A-L	1	PAMS	1 yr	E * +
Squib Operator	PXS PL V118A-T	1	ESF	24 hr	E *
Recirc Sump B Isolation	PXS PL V118B	1	ESF	24 hr	M *
Limit Switch	PXS PL V118B-L	1	PAMS	1 yr	E * +
Squib Operator	PXS PL V118B-T	1	ESF	24 hr	E *
Recirc Sump A	PXS PL V119A	1	ESF	24 hr	M *
Recirc Sump B	PXS PL V119B	1	ESF	24 hr	M *
Recirc Sump A	PXS PL V120A	1	ESF	24 hr	M *
Limit Switch	PXS PL V120A-L	1	PAMS	1 yr	E * +
Squib Operator	PXS PL V120A-T	1	ESF	24 hr	E *
Recirc Sump B	PXS PL V120B	1	ESF	24 hr	M *
Limit Switch	PXS PL V120B-L	1	PAMS	1 yr	E * +
Squib Operator	PXS PL V120B-T	1	ESF	24 hr	E *
IRWST Injection A	PXS PL V122A	1	ESF	24 hr	M *
IRWST Injection B	PXS PL V122B	1	ESF	24 hr	M *
IRWST Injection A	PXS PL V123A	1	ESF	24 hr	M *
Limit Switch	PXS PL V123A-L	1	PAMS	1 yr	E * +
Squib Operator	PXS PL V123A-T	1	ESF	24 hr	E *
IRWST Injection B	PXS PL V123B	1	ESF	24 hr	M *
Limit Switch	PXS PL V123B-L	1	PAMS	1 yr	E * +
Squib Operator	PXS PL V123B-T	1	ESF	24 hr	E *
IRWST Injection A	PXS PL V124A	1	ESF	24 hr	M *
IRWST Injection B	PXS PL V124B	1	ESF	24 hr	M *
IRWST Injection A	PXS PL V125A	1	ESF	24 hr	M *
Limit Switch	PXS PL V125A-L	1	PAMS	1 yr	E * +
Squib Operator	PXS PL V125A-T	1	ESF	24 hr	E *
IRWST Injection B	PXS PL V125B	1	ESF	24 hr	M *
Limit Switch	PXS PL V125B-L	1	PAMS	1 yr	E * +
Squib Operator	PXS PL V125B-T	1	ESF	24 hr	E *
First Stage ADS	RCS PL V001A	1	ESF	24 hr	M *
Limit Switch	RCS PL V001A-L	1	PAMS	1 yr	E *
Motor Operator	RCS PL V001A-M	1	ESF	24 hr	E *
First Stage ADS	RCS PL V001B	1	ESF	24 hr	M *
Limit Switch	RCS PL V001B-L	1	PAMS	1 yr	E *
Motor Operator	RCS PL V001B-M	1	ESF	24 hr	E *

Table 3.11-1 (Sheet 24 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Second Stage ADS	RCS PL V002A	1	ESF	24 hr	M *
Limit Switch	RCS PL V002A-L	1	PAMS	1 yr	E *
Motor Operator	RCS PL V002A-M	1	ESF	24 hr	E *
Second Stage ADS	RCS PL V002B	1	ESF	24 hr	M *
Limit Switch	RCS PL V002B-L	1	PAMS	1 yr	E *
Motor Operator	RCS PL V002B-M	1	ESF	24 hr	E *
Third Stage ADS	RCS PL V003A	1	ESF	24 hr	M *
Limit Switch	RCS PL V003A-L	1	PAMS	1 yr	E *
Motor Operator	RCS PL V003A-M	1	ESF	24 hr	E *
Third Stage ADS	RCS PL V003B	1	ESF	24 hr	M *
Limit Switch	RCS PL V003B-L	1	PAMS	1 yr	E *
Motor Operator	RCS PL V003B-M	1	ESF	24 hr	E *
Fourth Stage ADS	RCS PL V004A	1	ESF	24 hr	M *
Limit Switch	RCS PL V004A-L	1	PAMS	1 yr	E * +
Squib Operator	RCS PL V004A-T	1	ESF	24 hr	E *
Fourth Stage ADS	RCS PL V004B	1	ESF	24 hr	M *
Limit Switch	RCS PL V004B-L	1	PAMS	1 yr	E * +
Squib Operator	RCS PL V004B-T	1	ESF	24 hr	E *
Fourth Stage ADS	RCS PL V004C	1	ESF	24 hr	M *
Limit Switch	RCS PL V004C-L	1	PAMS	1 yr	E * +
Squib Operator	RCS PL V004C-T	1	ESF	24 hr	E *
Fourth Stage ADS	RCS PL V004D	1	ESF	24 hr	M *
Limit Switch	RCS PL V004D-L	1	PAMS	1 yr	E * +
Squib Operator	RCS PL V004D-T	1	ESF	24 hr	E *
PZR Safety Valve	RCS PL V005A	1	ESF	5 min	M *
Limit Switch	RCS PL V005A-L	1	PAMS	1 yr	E * +
PZR Safety Valve	RCS PL V005B	1	ESF	5 min	M *
Limit Switch	RCS PL V005B-L	1	PAMS	1 yr	E * +
ADS Discharge Header A Relief	RCS PL V010A	1	ESF	24 hr	M
ADS Discharge Header B Relief	RCS PL V010B	1	ESF	24 hr	M
First Stage ADS Isolation	RCS PL V011A	1	ESF	24 hr	M *
Limit Switch	RCS PL V011A-L	1	PAMS	1 yr	E *
Motor Operator	RCS PL V011A-M	1	ESF	24 hr	E *
First Stage ADS Isolation	RCS PL V011B	1	ESF	24 hr	M *
Limit Switch	RCS PL V011B-L	1	PAMS	1 yr	E *
Motor Operator	RCS PL V011B-M	1	ESF	24 hr	E *

Table 3.11-1 (Sheet 25 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Second Stage ADS Isolation	RCS PL V012A	1	ESF	24 hr	M *
Limit Switch	RCS PL V012A-L	1	PAMS	1 yr	E *
Motor Operator	RCS PL V012A-M	1	ESF	24 hr	E *
Second Stage ADS Isolation	RCS PL V012B	1	ESF	24 hr	M *
Limit Switch	RCS PL V012B-L	1	PAMS	1 yr	E *
Motor Operator	RCS PL V012B-M	1	ESF	24 hr	E *
Third Stage ADS Isolation	RCS PL V013A	1	ESF	24 hr	M *
Limit Switch	RCS PL V013A-L	1	PAMS	1 yr	E *
Motor Operator	RCS PL V013A-M	1	ESF	24 hr	E *
Third Stage ADS Isolation	RCS PL V013B	1	ESF	24 hr	M *
Limit Switch	RCS PL V013B-L	1	PAMS	1 yr	E *
Motor Operator	RCS PL V013B-M	1	ESF	24 hr	E *
Fourth Stage ADS Isolation	RCS V014A	1	ESF	24 hr	M *
Limit Switch	RCS V014A-L	1	PAMS	1 yr	E *
Motor Operator	RCS V014A-M	1	ESF	24 hr	E *
Fourth Stage ADS Isolation	RCS V014B	1	ESF	24 hr	M *
Limit Switch	RCS V014B-L	1	PAMS	1 yr	E *
Motor Operator	RCS V014B-M	1	ESF	24 hr	E *
Fourth Stage ADS Isolation	RCS V014C	1	ESF	24 hr	M *
Limit Switch	RCS V014C-L	1	PAMS	1 yr	E *
Motor Operator	RCS V014C-M	1	ESF	24 hr	E *
Fourth Stage ADS Isolation	RCS V014D	1	ESF	24 hr	M *
Limit Switch	RCS V014D-L	1	PAMS	1 yr	E *
Motor Operator	RCS V014D-M	1	ESF	24 hr	E *
Reactor Vessel Head Vent	RCS-PL V150A	1	ESF	5 min	E *
Limit Switch	RCS-PL V150A-L	1	PAMS	1 yr	E * +
Reactor Vessel Head Vent	RCS PL V150B	1	ESF	5 min	E *
Limit Switch	RCS PL V150B-L	1	PAMS	1 yr	E * +
Reactor Vessel Head Vent	RCS PL V150C	1	ESF	5 min	E *
Limit Switch	RCS PL V150C-L	1	PAMS	1 yr	E * +
Reactor Vessel Head Vent	RCS PL V150D	1	ESF	5 min	E *
Limit Switch	RCS PL V150D-L	1	PAMS	1 yr	E * +
RCS Inner Suction Isolation	RNS PL V001A	1	ESF	5 min	M *
Limit Switch	RNS PL V001A-L	1	PAMS	1 yr	E *
Motor Operator	RNS PL V001A-M	1	ESF	5 min	E *
RCS Inner Suction Isolation	RNS PL V001B	1	ESF	5 min	M *
Limit Switch	RNS PL V001B-L	1	PAMS	1 yr	E *
Motor Operator	RNS PL V001B-M	1	ESF	5 min	E *

Table 3.11-1 (Sheet 26 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
RCS Outer Suction Isolation	RNS PL V002A	1	ESF	5 min	M *
Limit Switch	RNS PL V002A-L	1	PAMS	1 yr	E *
Motor Operator	RNS PL V002A-M	1	ESF	5 min	E *
RCS Outer Suction Isolation	RNS PL V002B	1	ESF	5 min	M *
Limit Switch	RNS PL V002B-L	1	PAMS	1 yr	E *
Motor Operator	RNS PL V002B-M	1	ESF	5 min	E *
RCS Thermal Relief	RNS PL V003A	1	ESF	24 hr	M *
RCS Thermal Relief	RNS PL V003B	1	ESF	24 hr	M *
RHR Control/Isolation Valve	RNS PL V011	6	ESF	5 min	M S
Limit Switch	RNS PL V011-L	6	PAMS	2 wks	E
Motor Operator	RNS PL V011-M	6	ESF	5 min	E
RNS Discharge Containment Isolation	RNS PL V013	1	ESF	5 min	M *
RNS Discharge RCP B Isolation	RNS PL V015A	1	ESF	5 min	M *
RNS Discharge RCP B Isolation	RNS PL V015B	1	ESF	5 min	M *
RNS Discharge RCP B Isolation	RNS PL V017A	1	ESF	5 min	M *
RNS Discharge RCP B Isolation	RNS PL V017B	1	ESF	5 min	M *
RNS Hot Leg Suction Relief	RNS PL V021	1	ESF	24 hr	M *
RHR Pump Suction Header Isolation	RNS PL V022	6	ESF	5 min	M S
Limit Switch	RNS PL V022-L	6	PAMS	2 wks	E
Motor Operator	RNS PL V022-M	6	ESF	5 min	E
IRWST Suction Line Isolation	RNS PL V023	1	ESF	5 min	M *
Limit Switch	RNS PL V023-L	1	PAMS	1 yr	E *
Motor Operator	RNS PL V023-M	1	ESF	5 min	E *
RNS HX A Channel Head Drain	RNS PL V046	6	ESF	1 yr	M
RNS - CVS Containment Isolation	RNS PL V061	1	ESF	5 min	M *
Limit Switch	RNS PL V061-L	1	PAMS	1 yr	E *
Motor Operator	RNS PL V061-M	1	ESF	5 min	E *
Containment Isolation	SFS PL V034	1	ESF	5 min	M *
Limit Switch	SFS PL V034-L	1	PAMS	1 yr	E *
Motor Operator	SFS PL V034-M	1	ESF	5 min	E *
Containment Isolation	SFS PL V035	6	ESF	5 min	M S
Limit Switch	SFS PL V035-L	6	PAMS	2 wks	E
Motor Operator	SFS PL V035-M	6	ESF	5 min	E

Table 3.11-1 (Sheet 27 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
SFS Discharge Containment Isolation	SFS PL V037	1	ESF	5 min	M *
Containment Isolation	SFS PL V038	6	ESF	5 min	M S
Limit Switch	SFS PL V038-L	6	PAMS	2 wks	E
Motor Operator	SFS PL V038-M	6	ESF	5 min	E
Spent Fuel Pool to Cask Washdown Pit Isolation	SFS PL V066	6	ESF	2 wks	M
Cask Washdown Pit Drain Isolation	SFS PL V068	6	ESF	2 wks	M
Refueling Cavity to SG Compartment	SFS PL V071	1	ESF	2 wks	M *
Refueling Cavity to SG Compartment	SFS PL V072	1	ESF	2 wks	M *
PORV Block Valve	SGS PL V027A	5	ESF	5 min	M *
Limit Switch	SGS PL V027A-L	5	PAMS	2 wks	E *
Motor Operator	SGS PL V027A-M	5	ESF	5 min	E *
PORV Block Valve	SGS PL V027B	5	ESF	5 min	M *
Limit Switch	SGS PL V027B-L	5	PAMS	2 wks	E *
Motor Operator	SGS PL V027B-M	5	ESF	5 min	E *
Steam Safety Valve SG01	SGS PL V030A	5	ESF	5 min	M *
Limit Switch	SGS PL V030A-L	5	PAMS	2 wks	E * +
Steam Safety Valve SG02	SGS PL V030B	5	ESF	5 min	M *
Limit Switch	SGS PL V030B-L	5	PAMS	2 wks	E * +
Steam Safety Valve SG01	SGS PL V031A	5	ESF	5 min	M *
Limit Switch	SGS PL V031A-L	5	PAMS	2 wks	E * +
Steam Safety Valve SG02	SGS PL V031B	5	ESF	5 min	M *
Limit Switch	SGS PL V031B-L	5	PAMS	2 wks	E * +
Steam Safety Valve SG01	SGS PL V032A	5	ESF	5 min	M *
Limit Switch	SGS PL V032A-L	5	PAMS	2 wks	E * +
Steam Safety Valve SG02	SGS PL V032B	5	ESF	5 min	M *
Limit Switch	SGS PL V032B-L	5	PAMS	2 wks	E * +
Steam Safety Valve SG01	SGS PL V033A	5	ESF	5 min	M *
Limit Switch	SGS PL V033A-L	5	PAMS	2 wks	E * +
Steam Safety Valve SG02	SGS PL V033B	5	ESF	5 min	M *
Limit Switch	SGS PL V033B-L	5	PAMS	2 wks	E * +
Steam Safety Valve SG01	SGS PL V034A	5	ESF	5 min	M *
Limit Switch	SGS PL V034A-L	5	PAMS	2 wks	E * +
Steam Safety Valve SG02	SGS PL V034B	5	ESF	5 min	M *
Limit Switch	SGS PL V034B-L	5	PAMS	2 wks	E * +
Steam Safety Valve SG01	SGS PL V035A	5	ESF	5 min	M *
Limit Switch	SGS PL V035A-L	5	PAMS	2 wks	E * +
Steam Safety Valve SG02	SGS PL V035B	5	ESF	5 min	M *
Limit Switch	SGS PL V035B-L	5	PAMS	2 wks	E * +

Table 3.11-1 (Sheet 28 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Steamline Condensate					
Drain Isolation	SGS PL V036A	5	ESF	5 min	M *
Limit Switch	SGS PL V036A-L	5	PAMS	2 wks	E *
Solenoid Valve	SGS PL V036A-S	5	ESF	5 min	E *
Steamline Condensate Isolation	SGS PL V036B	5	ESF	5 min	M *
Limit Switch	SGS PL V036B-L	5	PAMS	2 wks	E *
Solenoid Valve	SGS PL V036B-S	5	ESF	5 min	E *
Main Steamline Isolation	SGS PL V040A	5	ESF	5 min	M *
Limit Switch	SGS PL V040A-L	5	PAMS	2 wks	E *
Solenoid Valve	SGS PL 040A-S	5	ESF	5 min	E *
Main Steamline Isolation	SGS PL V040B	5	ESF	5 min	M *
Limit Switch	SGS PL V040B-L	5	PAMS	2 wks	E *
Solenoid Valve	SGS PL 040B-S	5	ESF	5 min	E *
Main Feedwater Isolation	SGS PL V057A	5	ESF	5 min	M *
Limit Switch	SGS PL V057A-L	5	PAMS	2 wks	E *
Solenoid Valve	SGS PL V057A-S	5	ESF	5 min	E *
Main Feedwater Isolation	SGS PL V057B	5	ESF	5 min	M *
Limit Switch	SGS PL V057B-L	5	PAMS	2 wks	E *
Solenoid Valve	SGS PL V057B-S	5	ESF	5 min	E *
Startup Feedwater Isolation	SGS PL V067A	5	ESF	5 min	M *
Limit Switch	SGS PL V067A-L	5	PAMS	2 wks	E *
Motor Operator	SGS PL V067A-M	5	ESF	5 min	E *
Startup Feedwater Isolation	SGS PL V067B	5	ESF	5 min	M *
Limit Switch	SGS PL V067B-L	5	PAMS	2 wks	E *
Motor Operator	SGS PL V067B-M	5	ESF	5 min	E *
SG Blowdown Isolation	SGS PL V074A	10	ESF	5 min	M *
Limit Switch	SGS PL V074A-L	10	PAMS	2 wks	E *
Solenoid Valve	SGS PL V074A-S	10	ESF	5 min	E *
SG Blowdown Isolation	SGS PL V074B	10	ESF	5 min	M *
Limit Switch	SGS PL V074B-L	10	PAMS	2 wks	E *
Solenoid Valve	SGS PL V074B-S	10	ESF	5 min	E *
SG Series Blowdown Isolation	SGS PL V075A	10	ESF	5 min	M *
Solenoid Valve	SGS PL V075A-S	10	ESF	5 min	E *
SG Series Blowdown Isolation	SGS PL V075B	10	ESF	5 min	M *
Solenoid Valve	SGS PL V075B-S	10	ESF	5 min	E *
Steamline Condensate Drain	SGS PL V086A	5	ESF	5 min	M *
Isolation Solenoid Valve	SGS PL V086A-S	5	ESF	5 min	E *
Steamline Condensate Drain	SGS PL V086B	5	ESF	5 min	M *
Isolation Solenoid Valve	SGS PL V086B-S	5	ESF	5 min	E *
Power Operated Relief Valve	SGS PL V233A	5	ESF	5 min	M *
Limit Switch	SGS PL V233A-L	5	PAMS	2 wks	E * +
Solenoid Valve	SGS PL V233A-S	5	ESF	5 min	E *

Table 3.11-1 (Sheet 29 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Power Operated Relief Valve	SGS PL V233B	5	ESF	5 min	M *
Limit Switch	SGS PL V233B-L	5	PAMS	2 wks	E * +
Solenoid Valve	SGS PL V233B-S	5	ESF	5 min	E *
MSIV Bypass Isolation Valve	SGS PL V240A	5	ESF	5 min	M *
Limit Switch	SGS PL V240A-L	5	PAMS	2 wks	E *
Solenoid Valve	SGS PL V240A-S	5	ESF	5 min	E *
MSIV Bypass Isolation Valve	SGS PL V240B	5	ESF	5 min	M *
Limit Switch	SGS PL V240B-L	5	PAMS	2 wks	E *
Solenoid Valve	SGS PL V240B-S	5	ESF	5 min	E *
Main Feedwater Control Valve	SGS PL V250A	5	ESF	5 min	M *
Limit Switch (Closed)	SGS PL V250A-L	5	PAMS	2 wks	E * +
Solenoid Valve	SGS PL V250A-S	5	ESF	5 min	E *
Main Feedwater Control Valve	SGS PL V250B	5	ESF	5 min	M *
Limit Switch	SGS PL V250B-L	5	PAMS	2 wks	E * +
Solenoid Valve	SGS PL V250B-S	5	ESF	5 min	E *
Startup Feedwater Control Valve	SGS PL V255A	5	ESF	5 min	M *
Limit Switch	SGS PL V255A-L	5	PAMS	2 wks	E * +
Solenoid Valve	SGS PL V255A-S	5	ESF	5 min	E *
Startup Feedwater Control Valve	SGS PL V255B	5	ESF	5 min	M *
Limit Switch	SGS PL V255B-L	5	PAMS	2 wks	E * +
Solenoid Valve	SGS PL V255B-S	5	ESF	5 min	E *
MCR Isolation Valve	VBS PL V186	3	ESF	24 hr	M
Limit Switch	VBS PL V186-S	3	PAMS	2 wks	E+
Solenoid Valve	VBS PL V186-L	3	ESF	24 hr	E
MCR Isolation Valve	VBS PL V187	3	ESF	24 hr	M
Limit Switch	VBS PL V187-S	3	PAMS	2 wks	E+
Solenoid Valve	VBS PL V187-L	3	ESF	24 hr	E
MCR Isolation Valve	VBS PL V188	3	ESF	24 hr	M
Limit Switch	VBS PL V188-S	3	PAMS	2 wks	E+
Solenoid Valve	VBS PL V188-L	3	ESF	24 hr	E
MCR Isolation Valve	VBS PL V189	3	ESF	24 hr	M
Limit Switch	VBS PL V189-S	3	PAMS	2 wks	E+
Solenoid Valve	VBS PL V189-L	3	ESF	24 hr	E
MCR Isolation Valve	VBS PL V190	3	ESF	24 hr	M
Limit Switch	VBS PL V190-S	3	PAMS	2 wks	E+
Solenoid Valve	VBS PL V190-L	3	ESF	24 hr	E
MCR Isolation Valve	VBS PL V191	3	ESF	24 hr	M
Limit Switch	VBS PL V191-S	3	PAMS	2 wks	E+
Solenoid Valve	VBS PL V191-L	3	ESF	24 hr	E

Table 3.11-1 (Sheet 30 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Air Delivery Isolation Valve	VES PL V001	3	ESF	2 wks	M
Pressure Regulator Valve A	VES PL V002A	7	ESF	2 wks	M
Pressure Regulator Valve B	VES PL V002B	7	ESF	2 wks	M
Actuation Valve A	VES PL V005A	7	ESF	2 wks	E
Limit Switch	VES PL V005 A-L	7	PAMS	2 wks	E +
Actuation Valve B	VES PL V005B	7	ESF	2 wks	E
Limit Switch	VES PL V005 B-L	7	PAMS	2 wks	E +
Relief Isolation Valve A	VES PL V022A	3	ESF	2 wks	M
Solenoid Valve	VES PL V022A-S	3	ESF	2 wks	E
Relief Isolation Valve B	VES PL V022B	3	ESF	2 wks	M
Solenoid Valve	VES PL V022B-S	3	ESF	2 wks	E
Air Tank Relief A	VES PL V040A	7	ESF	2 wks	M
Air Tank Relief B	VES PL V040B	7	ESF	2 wks	M
Air Tank Relief A	VES PL V041A	7	ESF	2 wks	M
Air Tank Relief B	VES PL V041B	7	ESF	2 wks	M
Main Air Flowpath Isolation Valve	VES PL V044	3	ESF	2 wks	M
Containment Purge Inlet Isolation	VFS PL V003	7	ESF	5 min	M S
Limit Switch	VFS PL V003-L	7	PAMS	2 wks	E
Solenoid Valve	VFS PL V003-S	7	ESF	5 min	E
Containment Purge Inlet Isolation	VFS PL V004	1	ESF	5 min	M *
Limit Switch	VFS PL V004-L	1	PAMS	1 yr	E *
Solenoid Valve	VFS PL V004-S	1	ESF	5 min	E *
Containment Purge Discharge Isolation	VFS PL V009	1	ESF	5 min	M *
Limit Switch	VFS PL V009-L	1	PAMS	1 yr	E *
Solenoid Valve	VFS PL V009-S	1	ESF	5 min	E *
Containment Purge Discharge Isolation	VFS PL V010	6	ESF	5 min	M S
Limit Switch	VFS PL V010-L	6	PAMS	2 wks	E
Solenoid Valve	VFS PL V010-S	6	ESF	5 min	E
Fan Cooler Supply Isolation	VWS PL V058	2	ESF	5 min	M S
Limit Switch	VWS PL V058-L	2	PAMS	2 wks	E
Solenoid Valve	VWS PL V058-S	2	ESF	5 min	E
Fan Cooler Supply Isolation	VWS PL V062	1	ESF	5 min	M *

Table 3.11-1 (Sheet 31 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Fan Cooler Return Isolation	VWS PL V082	1	ESF	5 min	M *
Limit Switch	VWS PL V082-L	1	PAMS	1 yr	E *
Solenoid Valve	VWS PL V082-S	1	ESF	5 min	E *
Fan Cooler Return Isolation	VWS PL V086	2	ESF	5 min	M S
Limit Switch	VWS PL V086-L	2	PAMS	2 wks	E
Solenoid Valve	VWS PL V086-S	2	ESF	5 min	E
Sump Containment Isolation IRC	WLS PL V055	1	ESF	5 min	M *
Limit Switch	WLS PL V055-L	1	PAMS	1 yr	E *
Solenoid Valve	WLS PL V055-S	1	ESF	5 min	E *
Sump Containment Isolation ORC	WLS PL V057	7	ESF	5 min	M S
Limit Switch	WLS PL V057-L	7	PAMS	2 wks	E
Solenoid Valve	WLS PL V057-S	7	ESF	5 min	E
RCDT Gas Containment Isolation	WLS PL V067	1	ESF	5 min	M *
Limit Switch	WLS PL V067-L	1	PAMS	1 yr	E *
Solenoid Valve	WLS PL V067-S	1	ESF	5 min	E *
RCDT Gas Containment Isolation	WLS PL V068	7	ESF	5 min	M S
Limit Switch	WLS PL V068-L	7	PAMS	2 wks	E
Solenoid Valve	WLS PL V068-S	7	ESF	5 min	E
CVS To Sump	WLS PL V071 A	1	ESF	2 wks	M *
PXS A To Sump	WLS PL V071 B	1	ESF	2 wks	M *
PXS B To Sump	WLS PL V071 C	1	ESF	2 wks	M *
CVS To Sump	WLS PL V072 A	1	ESF	2 wks	M *
PXS A To Sump	WLS PL V072 B	1	ESF	2 wks	M *
PXS B To Sump	WLS PL V072 C	1	ESF	2 wks	M *

Table 3.11-1 (Sheet 32 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
MISCELLANEOUS					
Non-Active Valves					
Containment Penetration Test Connection Isolation	CAS-PL-V027	2	PB	1 yr	M
Service Air Supply Outside Containment Isolation	CAS-PL-V204	2	PB	1 yr	M
Service Air Supply Inside Containment Isolation	CAS-PL-V205	1	PB	1 yr	M *
Containment Penetration Test Connection Isolation	CAS-PL-V219	1	PB	1 yr	M *
Containment Isolation Valve Test Connection - Outlet Line	CCS-PL-V209	1	PB	1 yr	M *
Containment Isolation Valve Test Connection - Inlet Line	CCS-PL-V257	2	PB	1 yr	M
Resin Flush IRC Isolation	CVS-PL-V040	1	PB	1 yr	M *
Resin Flush ORC Isolation	CVS-PL-V041	10	PB	1 yr	M *
Letdown PZR Instrument Root	CVS-PL-V046	10	PB	1 yr	M *
Hydrogen Addition Containment Isolation Test Connection	CVS-PL-V096	1	PB	1 yr	M *
Demin Water Supply Containment Isolation - Outside	DWS-PL-V244	2	PB	1 yr	M
Demin Water Supply Containment Isolation - Inside	DWS-PL-V245	1	PB	1 yr	M *
Containment Penetration Test Connection Isolation	DWS-PL-V248	2	PB	1 yr	M
Fire Water Containment Test Connection Isolation	FPS-PL-V049	10	PB	1 yr	M *
Fire Water Containment Supply Isolation	FPS-PL-V050	10	PB	1 yr	M *
Fire Water Containment Test Connection Isolation	FPS-PL-V051	10	PB	1 yr	M *
Fire Water Containment Supply Isolation - Inside	FPS-PL-V052	1	PB	1 yr	M *
Flow Transmitter FT001 Root Valve	PCS-PL-V010A	9	PB	1 yr	M
Flow Transmitter FT001 Root Valve	PCS-PL-V010B	9	PB	1 yr	M
Flow Transmitter FT002 Root Valve	PCS-PL-V011A	9	PB	1 yr	M
Flow Transmitter FT001 Root Valve	PCS-PL-V011B	9	PB	1 yr	M
Flow Transmitter FT003 Root Valve	PCS-PL-V012A	9	PB	1 yr	M
Flow Transmitter FT003 Root Valve	PCS-PL-V012B	9	PB	1 yr	M
Flow Transmitter FT004 Root Valve	PCS-PL-V013A	9	PB	1 yr	M

Table 3.11-1 (Sheet 33 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Flow Transmitter FT004 Root Valve	PCS-PL-V013B	9	PB	1 yr	M
PCCWST Drain Isolation Valve	PCS-PL-V016	9	PB	1 yr	M
PCCWST Isolation Valve Leakage Detection Drain	PCS-PL-V029	9	PB	1 yr	M
PCCWST Isolation Valve Leakage Detection Crossconn	PCS-PL-V030	9	PB	1 yr	M
PCCWST Level Instrument Root Valve	PCS-PL-V031A	9	PB	1 yr	M
PCCWST Level Instrument Root Valve	PCS-PL-V031B	9	PB	1 yr	M
Recirculation Pump Suction from Long Term Makeup Isolation Valve	PCS-PL-V033	10	ESF	2 wks	M *
PCCWST Discharge Line Cross-Connect Isolation Valve	PCS-PL-V047	9	ESF	2 wks	M *
PZR Liquid Isolation	PSS-PL-V003A	1	PB	1 yr	M *
PZR Vapor Space Sample Isolation	PSS-PL-V003B	1	PB	1 yr	M *
PXS Accumulator Sample Isolation	PSS-PL-V004A	1	PB	1 yr	M *
PXS Accumulator Sample Isolation	PSS-PL-V004B	1	PB	1 yr	M *
PXS CMT A Sample Isolation	PSS-PL-V005A	1	PB	1 yr	M *
PXS CMT B Sample Isolation	PSS-PL-V005B	1	PB	1 yr	M *
PXC CMT A Sample Isolation	PSS-PL-V005C	1	PB	1 yr	M *
PXS CMT B Sample Isolation	PSS-PL-V005D	1	PB	1 yr	M *
CVS Demineralizer Sample Isolation	PSS-PL-V006	1	PB	1 yr	M *
Liquid Sample Check Valve	PSS-PL-V012A	1	PB	1 yr	M *
Liquid Sample Check Valve	PSS-PL-V012B	1	PB	1 yr	M *
PXS Accumulator A Sample Check Valve	PSS-PL-V020A	1	PB	1 yr	M *
PXS Accumulator B Sample Check Valve	PSS-PL-V020B	1	PB	1 yr	M *
CVS Demineralizer Sample Check Valve	PSS-PL-V035	1	PB	1 yr	M *
WLS Sump Sample Check Valve	PSS-PL-V039	1	PB	1 yr	M *
Containment Testing Boundary Isolation Valve	PSS-PL-V076A	1	PB	1 yr	M *
Containment Testing Boundary Isolation Valve	PSS-PL-V076B	1	PB	1 yr	M *
Containment Isolation Test Connection Isolation Valve	PSS-PL-V082	1	PB	1 yr	M *
Containment Isolation Test Connection Isolation Valve	PSS-PL-V083	1	PB	1 yr	M *

Table 3.11-1 (Sheet 34 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	**AP1000 Tag No.**	**Envir. Zone (Note 2)**	**Function (Note 1)**	**Operating Time Required (Note 5)**	**Qualification Program (Note 6)**
Containment Isolation Test Connection Isolation Valve	PSS-PL-V085	1	PB	1 yr	M *
Containment Isolation Test Connection Isolation Valve	PSS-PL-V086	1	PB	1 yr	M *
Core Makeup Tank A CL Inlet Isolation	PXS-PL-V002A	1	PB	1 yr	M *
Core Makeup Tank B CL Inlet Isolation	PXS-PL-V002B	1	PB	1 yr	M *
Core Makeup Tank A Upper Sample	PXS-PL-V010A	1	PB	1 yr	M *
Core Makeup Tank B Upper Sample	PXS-PL-V010B	1	PB	1 yr	M *
Core Makeup Tank A Lower Sample	PXS-PL-V011A	1	PB	1 yr	M *
Core Makeup Tank B Lower Sample	PXS-PL-V011B	1	PB	1 yr	M *
Core Makeup Tank A Drain	PXS-PL-V012A	1	PB	1 yr	M *
Core Makeup Tank B Drain	PXS-PL-V012B	1	PB	1 yr	M *
Core Makeup Tank Discharge Manual Isolation	PXS-PL-V013A	1	PB	1 yr	M *
Core Makeup Tank B Discharge Manual Isolation	PXS-PL-V013B	1	PB	1 yr	M *
Accumulator A N_2 Vent	PXS-PL-V021A	1	PB	1 yr	M *
Accumulator B N_2 Vent	PXS-PL-V021B	1	PB	1 yr	M *
Accumulator A PZR Transmitter Isolation	PXS-PL-V023A	1	PB	1 yr	M *
Accumulator B PZR Transmitter Isolation	PXS-PL-V023B	1	PB	1 yr	M *
Accumulator A PZR Transmitter Isolation	PXS-PL-V024A	1	PB	1 yr	M *
Accumulator B PZR Transmitter Isolation	PXS-PL-V024B	1	PB	1 yr	M *
Accumulator A Sample	PXS-PL-V025A	1	PB	1 yr	M *
Accumulator B Sample	PXS-PL-V025B	1	PB	1 yr	M *
Accumulator A Drain	PXS-PL-V026A	1	PB	1 yr	M *
Accumulator B Drain	PXS-PL-V026B	1	PB	1 yr	M *
Accumulator A Discharge Isolation	PXS-PL-V027A	1	PB	1 yr	M *
Accumulator B Discharge Isolation	PXS-PL-V027B	1	PB	1 yr	M *
Core Makeup Tank A Highpoint Vent	PXS-PL-V030A	1	PB	1 yr	M *
Core Makeup Tank B Highpoint Vent	PXS-PL-V030B	1	PB	1 yr	M *
Core Makeup Tank A Highpoint Vent	PXS-PL-V031A	1	PB	1 yr	M *
Core Makeup Tank B Highpoint Vent	PXS-PL-V031B	1	PB	1 yr	M *
Accumulator A Check Valve Drain	PXS-PL-V033A	1	PB	1 yr	M *
Accumulator B Check Valve Drain	PXS-PL-V033B	1	PB	1 yr	M *
Accumulator N_2 Containment Penetration Test Connection	PXS-PL-V052	1	PB	1 yr	M *

Table 3.11-1 (Sheet 35 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
PRHR HX Inlet Isolation	PXS-PL-V101	1	PB	1 yr	M *
PRHR HX Inlet Head Vent	PXS-PL-V102A	1	PB	1 yr	M *
PRHR HX Inlet Head Drain	PXS-PL-V102B	1	PB	1 yr	M *
PRHR HX Outlet Head Vent	PXS-PL-V103A	1	PB	1 yr	M *
PRHR HX Outlet Head Drain	PXS-PL-V103B	1	PB	1 yr	M *
PRHR HX Flow Transmitter A Isolation	PXS-PL-V104A	1	PB	1 yr	M *
PRHR HX Flow Transmitter B Isolation	PXS-PL-V104B	1	PB	1 yr	M *
PRHR HX Flow Transmitter A Isolation	PXS-PL-V105A	1	PB	1 yr	M *
PRHR HX Flow Transmitter B Isolation	PXS-PL-V105B	1	PB	1 yr	M *
PRHR HX/RCS Return Isolation	PXS-PL-V109	1	PB	1 yr	M *
PRHR HX Highpoint Vent	PXS-PL-V111A	1	PB	1 yr	M *
PRHR HX Highpoint Vent	PXS-PL-V111B	1	PB	1 yr	M *
PRHR HX PZR Transmitter Isolation	PXS-PL-V113	1	PB	1 yr	M *
IRWST Line A Isolation	PXS-PL-V121A	1	PB	1 yr	M *
IRWST Line B Isolation	PXS-PL-V121B	1	PB	1 yr	M *
IRWST Injection Check Test	PXS-PL-V126A	1	PB	1 yr	M *
IRWST Injection Check Test	PXS-PL-V126B	1	PB	1 yr	M *
IRWST to Containment Sump	PXS-PL-V127	1	PB	1 yr	M *
IRWST Injection Check Test	PXS-PL-V128A	1	PB	1 yr	M *
IRWST Injection Check Test	PXS-PL-V128B	1	PB	1 yr	M *
IRWST Injection Check Test	PXS-PL-V129A	1	PB	1 yr	M *
IRWST Injection Check Test	PXS-PL-V129B	1	PB	1 yr	M *
IRWST Level Transmitter A Isolation	PXS-PL-V150A	1	PB	1 yr	M *
IRWST Level Transmitter B Isolation	PXS-PL-V150B	1	PB	1 yr	M *
IRWST Level Transmitter C Isolation	PXS-PL-V150C	1	PB	1 yr	M *
IRWST Level Transmitter D Isolation	PXS-PL-V150D	1	PB	1 yr	M *
IRWST Level Transmitter A Isolation	PXS-PL-V151A	1	PB	1 yr	M *
IRWST Level Transmitter B Isolation	PXS-PL-V151B	1	PB	1 yr	M *
IRWST Level Transmitter C Isolation	PXS-PL-V151C	1	PB	1 yr	M *
IRWST Level Transmitter D Isolation	PXS-PL-V151D	1	PB	1 yr	M *

Table 3.11-1 (Sheet 36 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	**AP1000 Tag No.**	**Envir. Zone (Note 2)**	**Function (Note 1)**	**Operating Time Required (Note 5)**	**Qualification Program (Note 6)**
Accumulator A Leak Test	PXS-PL-V201A	1	PB	1 yr	M *
Accumulator B Leak Test	PXS-PL-V201B	1	PB	1 yr	M *
Accumulator A Leak Test	PXS-PL-V202A	1	PB	1 yr	M *
Accumulator B Leak Test	PXS-PL-V202B	1	PB	1 yr	M *
RNS Discharge Leak Test	PXS-PL-V205A	1	PB	1 yr	M *
RNS Discharge Leak Test	PXS-PL-V205B	1	PB	1 yr	M *
RNS Discharge Leak Test	PXS-PL-V206	1	PB	1 yr	M *
RNS Suction Leak Test	PXS-PL-V207A	1	PB	1 yr	M *
RNS Suction Leak Test	PXS-PL-V207B	1	PB	1 yr	M *
RNS Suction Leak Test	PXS-PL-V208A	1	PB	1 yr	M *
Core Makeup Tank A Fill Isolation	PXS-PL-V230A	1	PB	1 yr	M *
Core Makeup Tank B Fill Isolation	PXS-PL-V230B	1	PB	1 yr	M *
Core Makeup Tank A Fill Check	PXS-PL-V231A	1	PB	1 yr	M *
Core Makeup Tank B Fill Check	PXS-PL-V231B	1	PB	1 yr	M *
Accumulator A Fill/Drain Isolation	PXS-PL-V232A	1	PB	1 yr	M *
Accumulator B Fill/Drain Isolation	PXS-PL-V232B	1	PB	1 yr	M *
ADS Test Valve	RCS-PL-V007A	1	PB	1 yr	M *
ADS Test Valve	RCS-PL-V007B	1	PB	1 yr	M *
Fourth Stage ADS Isolation	RCS-PL-V014A	1	PB	1 yr	M *
Fourth Stage ADS Isolation	RCS-PL-V014B	1	PB	1 yr	M *
Fourth Stage ADS Isolation	RCS-PL-V014C	1	PB	1 yr	M *
Fourth Stage ADS Isolation	RCS-PL-V014D	1	PB	1 yr	M *
Hot Leg 2 Level Instrument Root	RCS-PL-V095	1	PB	1 yr	M *
Hot Leg 2 Level Instrument Root	RCS-PL-V096	1	PB	1 yr	M *
Hot Leg 1 Level Instrument Root	RCS-PL-V097	1	PB	1 yr	M *
Hot Leg 1 Level Instrument Root	RCS-PL-V098	1	PB	1 yr	M *
Cold Leg 1A Flow Meter Instrument Root	RCS-PL-V101A	1	PB	1 yr	M *
Cold Leg 1A Flow Meter Instrument Root	RCS-PL-V101B	1	PB	1 yr	M *
Cold Leg 1A Flow Meter Instrument Root	RCS-PL-V101C	1	PB	1 yr	M *
Cold Leg 1A Flow Meter Instrument Root	RCS-PL-V101D	1	PB	1 yr	M *
Cold Leg 1B Flow Meter Instrument Root	RCS-PL-V101E	1	PB	1 yr	M *
Cold Leg 1B Flow Meter Instrument Root	RCS-PL-V102A	1	PB	1 yr	M *
Cold Leg 1B Flow Meter Instrument Root	RCS-PL-V102B	1	PB	1 yr	M *
Cold Leg 1B Flow Meter Instrument Root	RCS-PL-V102C	1	PB	1 yr	M *
Cold Leg 1B Flow Meter Instrument Root	RCS-PL-V102D	1	PB	1 yr	M *
Cold Leg 2A Flow Meter Instrument Root	RCS-PL-V102E	1	PB	1 yr	M *

Table 3.11-1 (Sheet 37 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Cold Leg 2A Flow Meter Instrument Root	RCS-PL-V103A	1	PB	1 yr	M *
Cold Leg 2A Flow Meter Instrument Root	RCS-PL-V103B	1	PB	1 yr	M *
Cold Leg 2A Flow Meter Instrument Root	RCS-PL-V103C	1	PB	1 yr	M *
Cold Leg 2A Flow Meter Instrument Root	RCS-PL-V103D	1	PB	1 yr	M *
Cold Leg 2A Flow Meter Instrument Root	RCS-PL-V103E	1	PB	1 yr	M *
Cold Leg 2B Flow Meter Instrument Root	RCS-PL-V104A	1	PB	1 yr	M *
Cold Leg 2B Flow Meter Instrument Root	RCS-PL-V104B	1	PB	1 yr	M *
Cold Leg 2B Flow Meter Instrument Root	RCS-PL-V104C	1	PB	1 yr	M *
Cold Leg 2B Flow Meter Instrument Root	RCS-PL-V104D	1	PB	1 yr	M *
Cold Leg 2B Flow Meter Instrument Root	RCS-PL-V104E	1	PB	1 yr	M *
Hot Leg 1 Sample Isolation	RCS-PL-V108A	1	PB	1 yr	M *
Hot Leg 2 Sample Isolation	RCS-PL-V108B	1	PB	1 yr	M *
PZR Spray Valve	RCS-PL-V110A	1	PB	1 yr	M *
PZR Spray Valve	RCS-PL-V110B	1	PB	1 yr	M *
PZR Spray Block Valve	RCS-PL-V111A	1	PB	1 yr	M *
PZR Spray Block Valve	RCS-PL-V111B	1	PB	1 yr	M *
PZR Steam Space Sample Isolation	RCS-PL-V203	1	PB	1 yr	M *
PZR Manual Vent	RCS-PL-V204	1	PB	1 yr	M *
PZR Manual Vent	RCS-PL-V205	1	PB	1 yr	M *
PZR Spray Bypass	RCS-PL-V210A	1	PB	1 yr	M *
PZR Spray Bypass	RCS-PL-V210B	1	PB	1 yr	M *
PZR Level Steam Space Instrument Root	RCS-PL-V225A	1	PB	1 yr	M *
PZR Level Steam Space Instrument Root	RCS-PL-V225B	1	PB	1 yr	M *
PZR Level Steam Space Instrument Root	RCS-PL-V225C	1	PB	1 yr	M *
PZR Level Steam Space Instrument Root	RCS-PL-V225D	1	PB	1 yr	M *
PZR Level Liquid Space Instrument Root	RCS-PL-V226A	1	PB	1 yr	M *
PZR Level Liquid Space Instrument Root	RCS-PL-V226B	1	PB	1 yr	M *

Table 3.11-1 (Sheet 38 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
PZR Level Liquid Space Instrument Root	RCS-PL-V226C	1	PB	1 yr	M *
PZR Level Liquid Space Instrument Root	RCS-PL-V226D	1	PB	1 yr	M *
Wide Range PZR Level Steam Space Instrument Root	RCS-PL-V228	1	PB	1 yr	M *
Wide Range PZR Level Liquid Space Instrument Root	RCS-PL-V229	1	PB	1 yr	M *
Manual Head Vent	RCS-PL-V232	1	PB	1 yr	M *
Head Vent Isolation	RCS-PL-V233	1	PB	1 yr	M *
ADS Valve Discharge Header Drain Isolation	RCS-PL-V241	1	PB	1 yr	M *
RCP 1A Flush	RCS-PL-V260A	1	PB	1 yr	M *
RCP 1B Flush	RCS-PL-V260B	1	PB	1 yr	M *
RCP 2A Flush	RCS-PL-V260C	1	PB	1 yr	M *
RCP 2B Flush	RCS-PL-V260D	1	PB	1 yr	M *
RCP 1A Drain	RCS-PL-V261A	1	PB	1 yr	M *
RCP 1B Drain	RCS-PL-V261B	1	PB	1 yr	M *
RCP 2A Drain	RCS-PL-V261C	1	PB	1 yr	M *
RCP 2B Drain	RCS-PL-V261D	1	PB	1 yr	M *
RCS Pressure Boundary Valve Thermal Relief Isolation	RNS-PL-V004A	1	PB	1 yr	M *
RCS Pressure Boundary Valve Thermal Relief Isolation	RNS-PL-V004B	1	PB	1 yr	M *
RNS Pump A Suction Isolation	RNS-PL-V005A	6	PB	1 yr	M
RNS Pump B Suction Isolation	RNS-PL-V005B	6	PB	1 yr	M
RNS Pump A Discharge Isolation	RNS-PL-V007A	6	PB	1 yr	M
RNS Pump B Discharge Isolation	RNS-PL-V007B	6	PB	1 yr	M
RNS Discharge Containment Isolation Valve Test	RNS-PL-V010	6	PB	1 yr	M
RNS Discharge Containment Isolation Valve Test Connection, ORC	RNS-PL-V012	1	PB	1 yr	M *
RNS Discharge Containment Isolation Valve Test Connection	RNS-PL-V014	1	PB	1 yr	M *
RNS Discharge Containment Penetration Isolation Valves Test	RNS-PL-V016	1	PB	1 yr	M *
RNS Containment Isolation Test - Pump Suction, ORC	RNS-PL-V018	6	PB	1 yr	M
RNS Discharge to IRWST Isolation	RNS-PL-V024	1	PB	1 yr	M *
RNS Discharge to CVS	RNS-PL-V029	1	PB	1 yr	M *
RNS Train A Discharge Flow Instrument Isolation	RNS-PL-V031A	6	PB	1 yr	M
RNS Train B Discharge Flow Instrument Isolation	RNS-PL-V031B	6	PB	1 yr	M

Table 3.11-1 (Sheet 39 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
RNS Train A Discharge Flow Instrument Isolation	RNS-PL-V032A	6	PB	1 yr	M
RNS Train B Discharge Flow Instrument Isolation	RNS-PL-V032B	6	PB	1 yr	M
RNS Pump A Suction Pressure Instrument Isolation	RNS-PL-V033A	6	PB	1 yr	M
RNS Pump B Suction Pressure Instrument Isolation	RNS-PL-V033B	6	PB	1 yr	M
RNS Pump A Discharge Pressure Instrument Isolation	RNS-PL-V034A	6	PB	1 yr	M
RNS Pump B Discharge Pressure Instrument Isolation	RNS-PL-V034B	6	PB	1 yr	M
RNS Pump A Suction Piping Drain Isolation	RNS-PL-V036A	6	PB	1 yr	M
RNS Pump B Suction Piping Drain Isolation	RNS-PL-V036B	6	PB	1 yr	M
RNS Pump Discharge Relief	RNS-PL-V045	6	PB	1 yr	M
RNS HX B Channel Head Drain Isolation	RNS-PL-V048	6	PB	1 yr	M
RNS Pump A Casing Drain Isolation	RNS-PL-V050	6	PB	1 yr	M
RNS Pump B Casing Drain Isolation	RNS-PL-V051	6	PB	1 yr	M
RNS Pump Suction to Cask Loading Pit Isolation	RNS-PL-V056	6	PB	1 yr	M
RNS Pump Suction Containment Isolation Test Connection	RNS-PL-V059	6	PB	1 yr	M
SFS Refueling Cavity Drain To SGS Compartment Isolation	SFS-PL-V031	1	PB	1 yr	M *
SFS Refueling Cavity Suction Isolation	SFS-PL-V032	1	PB	1 yr	M *
SFS Refueling Cavity Drain to Containment Sump Isolation	SFS-PL-V033	1	PB	1 yr	M *
SFS Suction Line from IRWST Isolation	SFS-PL-V039	1	PB	1 yr	M *
SFS Fuel Transfer Canal Suction Isolation	SFS-PL-V040	6	PB	1 yr	M
SFS Cask Loading Pit Suction Isolation	SFS-PL-V041	6	PB	1 yr	M
SFS CVS Makeup Reverse Flow Prevention	SFS-PL-V043	6	PB	1 yr	M
SFS Demin Water Makeup to SFP Rev Flow Prevent	SFS-PL-V047	6	PB	1 yr	M
SFS Containment Penetration Test Connection	SFS-PL-V048	6	PB	1 yr	M

Table 3.11-1 (Sheet 40 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
SFS Cask Loading Pit Drain to WLS Isolation	SFS-PL-V049	6	PB	1 yr	M
SFS Containment Penetration Test Connection Isolation	SFS-PL-V056	1	PB	1 yr	M *
SFS Containment Isolation Valve V034 Test	SFS-PL-V058	1	PB	1 yr	M *
LT001 Root Isolation Valve	SGS-PL-V001A	1	PB	1 yr	M *
LT005 Root Isolation Valve	SGS-PL-V001B	1	PB	1 yr	M *
LT001 Root Isolation Valve	SGS-PL-V002A	1	PB	1 yr	M *
LT005 Root Isolation Valve	SGS-PL-V002B	1	PB	1 yr	M *
LT002 Root Isolation Valve	SGS-PL-V003A	1	PB	1 yr	M *
LT006 Root Isolation Valve	SGS-PL-V003B	1	PB	1 yr	M *
LT002 Root Isolation Valve	SGS-PL-V004A	1	PB	1 yr	M *
LT006 Root Isolation Valve	SGS-PL-V004B	1	PB	1 yr	M *
LT003 Root Isolation Valve	SGS-PL-V005A	1	PB	1 yr	M *
LT007 Root Isolation Valve	SGS-PL-V005B	1	PB	1 yr	M *
LT003 Root Isolation Valve	SGS-PL-V006A	1	PB	1 yr	M *
LT007 Root Isolation Valve	SGS-PL-V006B	1	PB	1 yr	M *
LT004 Root Isolation Valve	SGS-PL-V007A	1	PB	1 yr	M *
LT008 Root Isolation Valve	SGS-PL-V007B	1	PB	1 yr	M *
LT004 Root Isolation Valve	SGS-PL-V008A	1	PB	1 yr	M *
LT008 Root Isolation Valve	SGS-PL-V008B	1	PB	1 yr	M *
LT011 Root Isolation Valve	SGS-PL-V010A	1	PB	1 yr	M*
LT013 Root Isolation Valve	SGS-PL-V010B	1	PB	1 yr	M *
LT011 Root Isolation Valve	SGS-PL-V011A	1	PB	1 yr	M *
LT013 Root Isolation Valve	SGS-PL-V011B	1	PB	1 yr	M *
LT012 Root Isolation Valve	SGS-PL-V012A	1	PB	1 yr	M *
LT014 Root Isolation Valve	SGS-PL-V012B	1	PB	1 yr	M *
LT012 Root Isolation Valve	SGS-PL-V013A	1	PB	1 yr	M *
LT014 Root Isolation Valve	SGS-PL-V013B	1	PB	1 yr	M *
FT021 Root Isolation Valve	SGS-PL-V015A	1	PB	1 yr	M *
FT023 Root Isolation Valve	SGS-PL-V015B	1	PB	1 yr	M *
FT020 Root Isolation Valve	SGS-PL-V016A	1	PB	1 yr	M *
FT022 Root Isolation Valve	SGS-PL-V016B	1	PB	1 yr	M *
FT021 Root Isolation Valve	SGS-PL-V017A	1	PB	1 yr	M *
FT023 Root Isolation Valve	SGS-PL-V017B	1	PB	1 yr	M *
FT020 Root Isolation Valve	SGS-PL-V018A	1	PB	1 yr	M *
FT022 Root Isolation Valve	SGS-PL-V018B	1	PB	1 yr	M *
Main Steamline Vent Isolation	SGS-PL-V019A	1	PB	1 yr	M *
Main Steamline Vent Isolation	SGS-PL-V019B	1	PB	1 yr	M *
PT030 Root Isolation Valve	SGS-PL-V022A	5	PB	1 yr	M *
PT034 Root Isolation Valve	SGS-PL-V022B	5	PB	1 yr	M *
PT031 Root Isolation Valve	SGS-PL-V023A	5	PB	1 yr	M *
PT035 Root Isolation Valve	SGS-PL-V023B	5	PB	1 yr	M *
PT032 Root Isolation Valve	SGS-PL-V024A	5	PB	1 yr	M *

Table 3.11-1 (Sheet 41 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
PT036 Root Isolation Valve	SGS-PL-V024B	5	PB	1 yr	M *
PT033 Root Isolation Valve	SGS-PL-V025A	5	PB	1 yr	M *
PT037 Root Isolation Valve	SGS-PL-V025B	5	PB	1 yr	M *
Steamline 1 Nitrogen Supply Isolation	SGS-PL-V038A	5	PB	1 yr	M *
Steamline 2 Nitrogen Supply Isolation	SGS-PL-V038B	5	PB	1 yr	M *
MSIV Bypass Control Isolation	SGS-PL-V042A	5	PB	1 yr	M *
MSIV Bypass Control Isolation	SGS-PL-V042B	5	PB	1 yr	M *
MSIV Bypass Control Isolation	SGS-PL-V043A	5	PB	1 yr	M *
MSIV Bypass Control Isolation	SGS-PL-V043B	5	PB	1 yr	M *
SG1 Condensate Pipe Drain Valve	SGS-PL-V045A	5	PB	1 yr	M *
SG2 Condensate Pipe Drain Valve	SGS-PL-V045B	5	PB	1 yr	M *
LT015 Root Isolation Valve	SGS-PL-V046A	1	PB	1 yr	M *
LT017 Root Isolation Valve	SGS-PL-V046B	1	PB	1 yr	M *
LT015 Root Isolation Valve	SGS-PL-V047A	1	PB	1 yr	M *
LT017 Root Isolation Valve	SGS-PL-V047B	1	PB	1 yr	M *
LT016 Root Isolation Valve	SGS-PL-V048A	1	PB	1 yr	M *
LT018 Root Isolation Valve	SGS-PL-V048B	1	PB	1 yr	M *
LT016 Root Isolation Valve	SGS-PL-V049A	1	PB	1 yr	M *
LT018 Root Isolation Valve	SGS-PL-V049B	1	PB	1 yr	M *
LT044 Root Isolation Valve	SGS-PL-V050A	1	PB	1 yr	M *
LT046 Root Isolation Valve	SGS-PL-V050B	1	PB	1 yr	M *
LT044 Root Isolation Valve	SGS-PL-V051A	1	PB	1 yr	M *
LT046 Root Isolation Valve	SGS-PL-V051B	1	PB	1 yr	M *
LT045 Root Isolation Valve	SGS-PL-V052A	1	PB	1 yr	M *
LT047 Root Isolation Valve	SGS-PL-V052B	1	PB	1 yr	M *
LT045 Root Isolation Valve	SGS-PL-V053A	1	PB	1 yr	M *
LT047 Root Isolation Valve	SGS-PL-V053B	1	PB	1 yr	M *
PT062 Root Isolation Valve	SGS-PL-V056A	5	PB	1 yr	M *
PT063 Root Isolation Valve	SGS-PL-V056B	5	PB	1 yr	M *
Main Feedwater Check	SGS-PL-V058A	5	PB	1 yr	M *
Main Feedwater Check	SGS-PL-V058B	5	PB	1 yr	M *
FT055A Root Isolation Valve	SGS-PL-V062A	5	PB	1 yr	M *
FT056A Root Isolation Valve	SGS-PL-V062B	5	PB	1 yr	M *
FT055A Root Isolation Valve	SGS-PL-V063A	5	PB	1 yr	M *
FT056A Root Isolation Valve	SGS-PL-V063B	5	PB	1 yr	M *
FT055A Root Isolation Valve	SGS-PL-V064A	5	PB	1 yr	M *
FT056A Root Isolation Valve	SGS-PL-V064B	5	PB	1 yr	M *
FT055A Root Isolation Valve	SGS-PL-V065A	5	PB	1 yr	M *
FT056A Root Isolation Valve	SGS-PL-V065B	5	PB	1 yr	M *
SG1 Nitrogen Sparging Isolation	SGS-PL-V084A	1	PB	1 yr	M *
SG2 Nitrogen Sparging Isolation	SGS-PL-V084B	1	PB	1 yr	M *

Table 3.11-1 (Sheet 42 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Startup Feedwater Check Valve	SGS-PL-V256A	5	PB	1 yr	M *
Startup Feedwater Check Valve	SGS-PL-V256B	5	PB	1 yr	M *
MCR Penetration Test Valve	VBS-PL-V160	3	PB	1 yr	M
MCR Penetration Test Valve	VBS-PL-V161	3	PB	1 yr	M
MCR Penetration Test Valve	VBS-PL-V162	3	PB	1 yr	M
Air Delivery Line Pressure Instrument Isolation Valve A	VES-PL-V006A	7	PB	1 yr	M
Air Delivery Line Pressure Instrument Isolation Valve B	VES-PL-V006B	7	PB	1 yr	M
Temporary Instrument Isolation Valve A	VES-PL-V016	7	PB	1 yr	M
Temporary Instrument Isolation Valve A	VES-PL-V018	7	PB	1 yr	M
Temporary Instrument Isolation Valve B	VES-PL-V019	7	PB	1 yr	M
Temporary Instrument Isolation Valve B	VES-PL-V020	7	PB	1 yr	M
Air Tank Isolation Valve A	VES-PL-V024A	7	PB	1 yr	M
Air Tank Isolation Valve B	VES-PL-V024B	7	PB	1 yr	M
Air Tank Isolation Valve A	VES-PL-V025A	7	PB	1 yr	M
Air Tank Isolation Valve B	VES-PL-V025B	7	PB	1 yr	M
Refill Line Isolation Valve	VES-PL-038	7	PB	1 yr	M
DP Instrument Line Isolation Valve A	VES-PL-V043A	3	PB	1 yr	M
DP Instrument Line Isolation Valve B	VES-PL-V043B	3	PB	1 yr	M
Containment Isolation Test Connection	VFS-PL-V001	7	PB	1 yr	M
Containment Isolation Test Connection	VFS-PL-V002	1	PB	1 yr	M *
Containment Isolation Test Connection	VFS-PL-V006	1	PB	1 yr	M *
Containment Isolation Test Connection	VFS-PL-V007	6	PB	1 yr	M
Containment Isolation Test Connection	VFS-PL-V008	6	PB	1 yr	M
Main Equipment Hatch Test Connection	VUS-PL-V015	7	PB	1 yr	M
Maintenance Equipment Hatch Test Connection	VUS-PL-V016	7	PB	1 yr	M
Personnel Hatch Test Connection	VUS-PL-V017	7	PB	1 yr	M
Personnel Hatch Test Connection	VUS-PL-V018	7	PB	1 yr	M
Personnel Hatch Test Connection	VUS-PL-V019	7	PB	1 yr	M
Personnel Hatch Test Connection	VUS-PL-V020	7	PB	1 yr	M
Personnel Hatch Test Connection	VUS-PL-V021	7	PB	1 yr	M
Personnel Hatch Test Connection	VUS-PL-V022	7	PB	1 yr	M
Fuel Transfer Tube Test Connection	VUS-PL-V023	11	PB	1 yr	M *

Table 3.11-1 (Sheet 43 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Electrical Penetration Test Isolation Valve	VUS-PL-V101	4	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V102	4	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V103	4	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V104	4	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V105	4	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V106	2	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V107	2	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V108	2	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V109	2	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V110	2	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V111	2	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V112	4	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V113	4	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V114	4	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V115	4	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V116	4	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V117	4	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V118	4	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V119	2	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V120	2	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V121	2	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V122	2	PB	1 yr	M

Table 3.11-1 (Sheet 44 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Electrical Penetration Test Isolation Valve	VUS-PL-V123	2	PB	1 yr	M
Electrical Penetration Test Isolation Valve	VUS-PL-V124	2	PB	1 yr	M
Spare Penetration Test Connection	VUS-PL-V140	7	PB	1 yr	M
Spare Penetration Test Connection	VUS-PL-V141	7	PB	1 yr	M
Spare Penetration Test Connection	VUS-PL-V142	7	PB	1 yr	M
VWS Supply Containment Penetration IRC Test Connection/Vent	VWS-PL-V424	1	PB	1 yr	M *
VWS Return Containment Penetration ORC Test Connection/Vent	VWS-PL-V425	2	PB	1 yr	M
Heat Exchangers					
Normal Residual Heat Removal Heat Exchanger A	RNS-ME-01A	6	PB	1 yr	M
Normal Residual Heat Removal Heat Exchanger B	RNS-ME-01B	6	PB	1 yr	M
Tanks					
Spent Fuel Pool	FHS-MT-01	11	ESF	1 yr	M *
Fuel Transfer Canal	FHS-MT-02	11	ESF	1 yr	M *
Spent Fuel Cask Loading Pit	FHS-MT-05	6	ESF	1 yr	M
Passive Containment Cooling Water Storage Tank	PCS-MT-01	9	ESF	1 yr	M
Water Distribution Bucket	PCS-MT-03	9	ESF	1 yr	M
Water Collection Troughs	PCS-MT-04	9	ESF	1 yr	M
Passive RHR Heat Exchanger	PXS-ME-01	1	ESF	1 yr	M *
Accumulator Tank A	PXS-MT-01A	1	ESF	1 yr	M *
Accumulator Tank B	PXS-MT-01B	1	ESF	1 yr	M *
Core Makeup Tank A	PXS-MT-02A	1	ESF	1 yr	M *
Core Makeup Tank B	PXS-MT-02B	1	ESF	1 yr	M *
In-Containment Refueling Water Storage Tank	PXS-MT-03	1	ESF	1 yr	M *
Emergency Air Storage Tank 01	VES-MT-01	7	ESF	1 yr	M
Emergency Air Storage Tank 02	VES-MT-02	7	ESF	1 yr	M
Emergency Air Storage Tank 03	VES-MT-03	7	ESF	1 yr	M
Emergency Air Storage Tank 04	VES-MT-04	7	ESF	1 yr	M
Emergency Air Storage Tank 05	VES-MT-05	7	ESF	1 yr	M
Emergency Air Storage Tank 06	VES-MT-06	7	ESF	1 yr	M
Emergency Air Storage Tank 07	VES-MT-07	7	ESF	1 yr	M
Emergency Air Storage Tank 08	VES-MT-08	7	ESF	1 yr	M
Emergency Air Storage Tank 09	VES-MT-09	7	ESF	1 yr	M

Table 3.11-1 (Sheet 45 of 45)

ENVIRONMENTALLY QUALIFIED ELECTRICAL AND MECHANICAL EQUIPMENT

Description	AP1000 Tag No.	Envir. Zone (Note 2)	Function (Note 1)	Operating Time Required (Note 5)	Qualification Program (Note 6)
Emergency Air Storage Tank 10	VES-MT-10	7	ESF	1 yr	M
Emergency Air Storage Tank 11	VES-MT-11	7	ESF	1 yr	M
Emergency Air Storage Tank 12	VES-MT-12	7	ESF	1 yr	M
Emergency Air Storage Tank 13	VES-MT-13	7	ESF	1 yr	M
Emergency Air Storage Tank 14	VES-MT-14	7	ESF	1 yr	M
Emergency Air Storage Tank 15	VES-MT-15	7	ESF	1 yr	M
Emergency Air Storage Tank 16	VES-MT-16	7	ESF	1 yr	M
Emergency Air Storage Tank 17	VES-MT-17	7	ESF	1 yr	M
Emergency Air Storage Tank 18	VES-MT-18	7	ESF	1 yr	M
Emergency Air Storage Tank 19	VES-MT-19	7	ESF	1 yr	M
Emergency Air Storage Tank 20	VES-MT-20	7	ESF	1 yr	M
Emergency Air Storage Tank 21	VES-MT-21	7	ESF	1 yr	M
Emergency Air Storage Tank 22	VES-MT-22	7	ESF	1 yr	M
Emergency Air Storage Tank 23	VES-MT-23	7	ESF	1 yr	M
Emergency Air Storage Tank 24	VES-MT-24	7	ESF	1 yr	M
Emergency Air Storage Tank 25	VES-MT-25	7	ESF	1 yr	M
Emergency Air Storage Tank 26	VES-MT-26	7	ESF	1 yr	M
Emergency Air Storage Tank 27	VES-MT-27	7	ESF	1 yr	M
Emergency Air Storage Tank 28	VES-MT-28	7	ESF	1 yr	M
Emergency Air Storage Tank 29	VES-MT-29	7	ESF	1 yr	M
Emergency Air Storage Tank 30	VES-MT-30	7	ESF	1 yr	M
Emergency Air Storage Tank 31	VES-MT-31	7	ESF	1 yr	M
Emergency Air Storage Tank 32	VES-MT-32	7	ESF	1 yr	M
Main Feed Pump A Status	ECS ES 3 XXX	8	PAMS	2 wks	E +
Main Feed Pump B Status	ECS ES 4 XXX	8	PAMS	2 wks	E +
Main Feed Pump C Status	ECS ES 5 XXX	8	PAMS	2 wks	E+

Notes:

1. RT (Reactor Trip), ESF (Engineered Safeguards Feature), PAMS (Post-Accident Monitoring), ISOL (Isolation), PB (Pressure Boundary)
2. Zones identified in Table 3D.5-1
3. Not required post-accident
4. Note deleted
5. Reference Table 3D.4-2
6. E = Electrical Equipment Program
   M = Mechanical Equipment Program
   * = Harsh Environment
   + = Seismic Qualification not required
   S = Qualified for operation with spray from a moderate-energy pipe crack or spray from a cold high energy pipe crack.
7. The Protection and Safety Monitoring Cabinets will be qualified to meet the function operating times identified in this table.

APPENDIX 3A

HVAC DUCTS AND DUCT SUPPORTS

This appendix provides the design criteria for seismic Category I and II HVAC ducts and their supports. These design criteria maintain structural integrity for seismic Category I and II ducts and functional capability for seismic Category I duct.

The structural components of a typical HVAC duct system include the sheet metal ducts, stiffeners for the ducts, duct supports, and other inline components such as duct heaters, dampers, etc.

3A.1 Codes and Standards

The design of the HVAC ducts and their supports conform to the following codes and standards:

- ASME N509-1989(R1996), Nuclear Power Plants Air Ventilating Systems and Components
- ASME/ANSI AG-1-1997, Code on Nuclear Air and Gas Treatment
- American Institute of Steel Construction (AISC), Specification for the Design, Fabrication and Erection of Steel Safety Related Structures for Nuclear Facilities, AISC-N690-1994
- American Iron and Steel Institute (AISI), Specification for the Design of Cold Formed Steel Structural Members, 1996 Edition and Supplement No. 1, July 30, 1999
- SMACNA, HVAC Duct Construction Standards, Metal and Flexible, Second Edition 1995.

3A.2 Loads and Load Combinations

3A.2.1 Loads

3A.2.1.1 Dead Load (D)

Dead load includes the weight of the duct sheet, stiffeners and inline components such as duct heaters and dampers. It also includes permanently attached items such as insulation and fireproofing, where applicable, and the weight of the duct supports. Temporary items used during construction or maintenance are removed prior to operation.

3A.2.1.2 Construction Live Load (L)

Live load consists of a load of 250 pounds to be applied only during construction or maintenance on an area of 10 square inches on the duct at a critical location to maximize flexural and shear stresses. This load is not combined with seismic loads.

3A.2.1.3 Pressure (P)

The duct metal thickness and stiffener requirements are based on maximum system design pressures. SMACNA or ASME guidelines, as applicable, are used in the design of duct metal thickness and stiffener requirements.

The pressure loads occur during normal plant operation, including plant start up testing, damper closure and normal airflow. Occasionally, overpressure transient loads such as rapid damper closure may also produce short duration pressure differential.

3A.2.1.4 Safe Shutdown Earthquake (E_s)

Seismic response of the HVAC ductwork and its support system are produced due to seismic excitation of the supports.

3A.2.1.5 Wind Loads (W)

Ductwork within partially or fully vented buildings are subject to wind effects. Design wind loads are discussed in Section 3.3.

3A.2.1.6 Tornado Loads (W_t)

Ductwork within partially or fully vented buildings are subject to tornado differential pressure effects. Tornado loads are discussed in Section 3.3. Seismic Category I HVAC ductwork is protected from impact by tornado missiles.

3A.2.1.7 External Pressure Differential Loads (P_A)

Seismic Category I HVAC ductwork and its supports are designed to withstand dynamic external pressure differential loads resulting from postulated accident conditions. Usually HVAC ducts are routed outside the areas of potential pipe break.

3A.2.1.8 Thermal (T_O/T_A)

Stresses on the supports resulting from the ductwork expansion due to temperature changes are avoided by designing the system to take care of the expansion or by utilizing expansion joints. For ducts of gasketed companion angle construction, thermal loads are negligible. For ducts exposed to higher temperatures during a postulated accident condition, an evaluation is performed on a case by case basis for its effect.

3A.2.2 Load Combinations

The load combinations for various service levels are as follows:

Service Level		Load Combination
A	(Construction / maintenance)	$D + L + P + T_O$
A	(Normal Operating Condition)	$D + P + T_O$

B	(Severe Condition)	$D + W + P + T_O$
C	(Extreme Condition)	$D + E_s + P + T_O$
C	(Extreme Condition)	$D + W_t + P + T_O$
D	(Abnormal Condition)	$D + P + P_A + E_s + T_A$

3A.3 Analysis and Design

The HVAC duct support system is designed to maintain structural integrity of the duct. Function is not required for the seismic Category II ductwork. The stresses are maintained within the allowable limits specified in subsection 3A.3.4. Section properties and masses are calculated in accordance with SMACNA standard.

The damping values for seismic analysis are as follows:

- Welded HVAC Ductwork 4 percent
- Bolted HVAC Ductwork 7 percent

The duct design due to pressure loads is based on ASME/ANSI AG-1 for seismic Category I ducts and SMACNA for seismic Category II ducts.

The global behavior of the duct is determined from the overall bending of the duct between the supports. It is similar to the beam type bending. The dead load is combined with the seismic inertial load to determine the maximum bending moment. For determining the section modulus, the corners of the duct are considered effective. The corner length in each direction equals 32 times the thickness of the duct (t) for this purpose.

3A.3.1 Response Due to Seismic Loads

The methodology for seismic analysis is provided in subsection 3.7.3. Seismic loads are determined by either using the equivalent static load method of analysis or by performing dynamic analysis.

Stresses are determined for the seismic excitation in two horizontal and one vertical direction. The stresses in the three directions are combined using the square root of sum of the squares (SRSS) method as described in subsection 3.7.2.6.

3A.3.2 Deflection Criteria

Deflections for panels and stiffeners conform to the limits stated in the Code for "Nuclear Air and Gas Treatment."

3A.3.3 Relative Movement

Clearances are provided for allowing relative movement between equipment, other commodities, and HVAC system.

3A.3.4 Allowable Stresses

The basic stress allowables for the HVAC ducts are in accordance with paragraph SA-4220 of ASME/ANSI AG-1.

The basic stress allowables for duct supports utilizing rolled structural shapes are in accordance with ANSI/AISC N-690 and the supplemental requirements described in subsection 3.8.4.5.2. The basic stress allowables for supports utilizing light gage cold rolled channel type sections are based on the manufacturer's published catalog values.

Service Level A and B Basic Allowable

Service Level C and D 1.6 times basic allowable for tension and 1.4 times basic allowable for compression

3A.3.5 Connections

Connections are designed in accordance with the applicable codes and standards listed in subsection 3A.1. For connections used with light gage cold rolled channel type sections, design is based on the manufacturer's published catalog values. Supports are attached to the building structure by bolted or welded connections. Fastening of the supports to concrete structures meets the supplemental requirements given in subsection 3.8.4.5.1.

APPENDIX 3B

LEAK-BEFORE-BREAK EVALUATION OF THE AP1000 PIPING

General Design Criterion 4 requires that structures, systems, and components important to safety be designed to accommodate the effects of conditions associated with normal operation, anticipated transients, and postulated accident conditions. However, the dynamic effects and flooding associated with pipe rupture may be excluded when analysis demonstrates that the probability of fluid system pipe rupture is extremely low. Dynamic effects are not considered for those segments of piping that are shown mechanistically, with a large margin, not to be susceptible to a pipe rupture.

The dynamic effects associated with pipe rupture include effects such as pipe break reaction loads, jets and jet impingement, subcompartment pressurization loads, and transient pipe rupture depressurization loads on other components.

The use of mechanistic pipe break to eliminate evaluation of dynamic effects of pipe rupture includes material selection, inspection, leak detection, and analysis. Subsection 3.6.3 outlines considerations relative to material selection, inspections, and leak detection. Subsection 5.2.5 describes the leak detection system inside containment. This appendix describes the analysis methods used to support the application of mechanistic pipe break to high-energy piping in the AP1000.

The analysis and criteria to eliminate dynamic effects of pipe breaks are encompassed in a methodology called leak-before-break (LBB). This methodology has been validated by theoretical investigations and test demonstrations sponsored by the industry and the NRC.

The primary regulatory documents for leak-before-break analyses are General Design Criterion No. 4 (GDC-4), Draft Standard Review Plan 3.6.3 (SRP 3.6.3) (Reference 1), and NUREG-1061, Volume 3 (Reference 2). Although SRP 3.6.3 has been issued only as a draft, its provisions are followed as guidelines to leak-before-break analyses.

Leak-before-break methodology has been applied to the reactor coolant loop and high-energy auxiliary line piping in operating nuclear power plants. The leak-before-break analysis used to support the piping design of the AP1000 is an application of the same methodology used in leak-before-beak evaluations previously accepted by the NRC.

In the AP1000, leak-before-break evaluations are performed for the reactor coolant loop, the surge line, selected other branch lines containing reactor coolant down to and including 6-inch diameter nominal pipe size, and portions of the main steam line. Those lines not qualified to the leak-before-break criteria are evaluated using the pipe rupture protection criteria outlined in subsections 3.6.1 and 3.6.2.

This appendix provides a leak-before-break analysis for the applicable piping systems. Table 3B-1 provides a list of AP1000 leak-before-break piping systems.

3B.1 Leak-Before-Break Criteria for AP1000 Piping

The methodology used for leak-before-break analysis is consistent with that set forth in GDC-4, SRP 3.6.3 (Reference 1) and NUREG-1061, Volume 3 (Reference 2). The steps are:

- Evaluate potential failure mechanisms
- Perform bounding analysis

3B.2 Potential Failure Mechanisms for AP1000 Piping

In high-energy piping, there are material degradation mechanisms that could adversely affect the integrity of the system as well as its suitability for leak-before-break analysis. The following lists potential degradation (or "failure") mechanisms:

- Erosion-corrosion induced wall thinning
- Stress corrosion cracking (SCC)
- Water hammer
- Fatigue
- Thermal aging
- Thermal stratification
- Other mechanisms

The stainless steel piping is fabricated of SA312TP316LN or SA312TP304L material. The type 304L material is used in the accumulator discharge lines. The main steam piping is fabricated of SA333 Grade 6. The welds are made by the gas tungsten arc welding (GTAW) method.

The various degradation mechanisms are discussed in the following subsections.

3B.2.1 Erosion-Corrosion Induced Wall Thinning

Primary Loop Piping

Wall thinning by erosion and erosion-corrosion effects does not occur in the primary loop piping because SA312TP316LN austenitic stainless steel material is highly resistant to these effects. The coolant velocity in the AP1000 primary loop is about 76 feet per second. This flow velocity is not expected to create erosion-corrosion effects since stainless steels are considered to be virtually immune (Reference 3). A review of erosion-corrosion in nuclear power systems (Reference 4) reported that "stainless steels are increasingly being used due to their excellent resistance to erosion-corrosion, even at high water velocities, 40 m/s (131 ft/sec)." The bend radii in the AP1000 hot and cold legs are greater than the bend radii used in the crossover legs of operating plants. There is no record of erosion-corrosion induced wall thinning in the primary loops of operating plants.

Auxiliary Stainless Steel Piping

Wall thinning by erosion-corrosion effects does not occur in the auxiliary stainless steel piping because SA312TP316LN and SA304TP304L austenitic stainless materials are highly resistant to these effects. The coolant velocity in these systems is lower than in comparable systems in operating Westinghouse-designed pressurized water reactors. There is no record of erosion-corrosion induced wall thinning in the stainless steel piping of operating plants.

Main Steam Line

Main steam lines in the AP1000 are fabricated from SA333 Grade 6 Carbon steel. Erosion-corrosion induced wall thinning is not expected in the main steam line. Extensive work has been done investigating erosion-corrosion in carbon steel pipes. The main steam line has low susceptibility to erosion due to the relatively high operating temperature. Susceptibility is also low due to the high quality steam in the main steam line.

Based on the above discussion, erosion-corrosion induced wall thinning does not have an adverse effect on the integrity of the AP1000 leak-before-break piping systems.

3B.2.2 Stress Corrosion Cracking

Stress corrosion cracking is not expected to occur in the AP1000 piping systems because the three conditions necessary for stress corrosion cracking to take place are not present. If any of these three conditions is not present, stress corrosion cracking will not take place. The three conditions are:

- There must be a corrosive environment.
- The material itself must be susceptible.
- Tensile stresses must be present in the material.

Primary Loop Piping

During plant operation, the reactor coolant water chemistry is monitored and maintained within specific limits (see subsection 5.2.3 for a discussion of reactor coolant chemistry). Contaminant concentrations are kept below the thresholds known to be conducive to stress corrosion cracking. The major water chemistry control standards are included in the plant operating procedures as a condition for plant operation.

The key to avoidance of a corrosive environment is control of oxygen. During normal power operation, oxygen concentration in the reactor coolant system is controlled to extremely low levels by controlling charging flow chemistry and maintaining a hydrogen overpressure in the reactor coolant at specified concentrations. Halogen concentration is controlled by maintaining concentrations of chlorides and fluorides within the specified limits. During plant operations, the likelihood of stress corrosion cracking in the primary loop piping systems is very low.

The elements of a water environment known to increase the susceptibility of austenitic stainless steel to stress corrosion are oxygen, fluorides, chlorides, hydroxides, hydrogen peroxide, and reduced forms of sulfur (for example, sulfides, sulfites, and thionates). Pipe cleaning standards

prior to operation and careful water chemistry control during plant operation are applied to prevent the occurrence of a corrosive environment. Before being placed in service the piping is cleaned. During flushes and preoperational testing, water chemistry is controlled according to written specifications. Standards on chlorides, fluorides, conductivity, and pH are included in the guidelines for water for cleaning the piping.

The SA312TP316LN austenitic stainless steel chosen for the AP1000 is resistant to stress corrosion cracking in a low- or no-oxygen environment. The "L" grades of austenitic stainless steel contain low carbon (less than 0.035 weight percent) which mitigates sensitization.

Design tensile stresses in the reactor coolant loop are within the ASME Code, Section III allowables. Residual tensile stresses are expected in the welds and such stresses are not considered when designing by the ASME Code, Section III because these stresses are self-equilibrating and do not affect the failure loads. The residual stresses should not be more severe than for the operating Westinghouse pressurized water reactor plants (which have not experienced stress corrosion cracking in the primary loop).

The material used for buttering nozzles at the stainless-to-carbon steel safe ends is a high nickel alloy. The nickel-chromium-iron alloy selected and qualified for this application is not susceptible to primary water stress corrosion cracking.

Auxiliary Stainless Steel Piping

The discussion above regarding the necessary conditions for primary loop piping stress corrosion cracking is also applicable to the other stainless steel piping of the primary system.

The SA376TP316LN/SA312TP316LN/SA312TP304L austenitic stainless steel chosen for the auxiliary stainless steel piping of the AP1000 is resistant to stress corrosion cracking in a low- or no-oxygen environment. The "L" grades of austenitic stainless steel contain low carbon (less than 0.035 weight percent) which mitigates sensitization.

Design tensile stresses in the other stainless steel piping are within the ASME Code, Section III allowables. Residual tensile stresses are expected in the welds; however, the residual stresses should not be more severe than for the operating Westinghouse pressurized water reactor plants (which have not experienced stress corrosion cracking in the auxiliary stainless steel piping).

Main Steam Line

The main steam piping is constructed from ferritic steel. Stress corrosion cracking in ferritic steels commonly result from a caustic environment. A source of a caustic environment in the main steam piping would be moisture carryover from the steam generator. However, the secondary side water treatment utilizes all volatile treatment. All volatile treatment effectively precludes causticity in the steam generator bulk liquid environment. For some operating plants prior to implementing all volatile treatment, the phosphate water treatment caused a caustic chemical imbalance resulting in stress corrosion cracking of steam generator tubing. Under all volatile treatment water treatment conditions, there is no instance of caustic stress corrosion cracking on the ferritic steam lines indicating no significant caustic carryover. The operating secondary side chemistry precludes stress corrosion cracking on the ferritic main steam line.

Based on the above discussion, stress corrosion cracking does not have an adverse effect on the integrity of AP1000 leak-before-break piping systems.

3B.2.3 Water Hammer

Primary Loop Piping

The reactor coolant loop is designed to operate at a pressure greater than the saturation pressure of the coolant, thus precluding the voiding conditions necessary for water hammer to occur. The reactor coolant primary system is designed for Level A, B, C, and D (normal, upset, emergency, and faulted) service condition transients. The design requirements are conservative relative to both the number of transients and their severity. Relief valve actuation and the associated hydraulic transients following valve opening have been considered in the system design. Other valve and pump actuations cause relatively slow transients with no significant effect on the system dynamic loads.

To provide dynamic system stability, reactor coolant parameters are controlled. Temperature during normal operation is maintained within a narrow range by control rod positioning. Pressure is controlled within a narrow range for steady-state conditions by pressurizer heaters and pressurizer spray. The flow characteristics of the system remain constant during a fuel cycle. The operating transients of the reactor coolant system primary loop piping are such that significant water hammer loads are not expected to occur.

Auxiliary Stainless Steel Piping

The passive core cooling system and automatic depressurization system are designed to minimize the potential for water hammer induced dynamic loads. Design features include:

- Continuously sloping core makeup tank and passive residual heat exchanger inlet lines to eliminate local high points
- Inlet diffusers in the core makeup tanks to preclude adverse steam and water interactions
- Vacuum breakers in the discharge lines of the automatic depressurization valves connected to the pressurizer

The AP1000 pressurizer spray control valve is similar to what is used in the operating plants. There is no history of water hammer caused by the spray control valve.

The normal residual heat removal system isolation valves are slow closing valves, identical to operating plants, and therefore would not be a source of water hammer.

These features minimize the potential of water hammer in the auxiliary stainless steel piping system.

Main Steam Line

The steam lines are not subject to water hammer by the nature of the fluid transported. The following system design provisions address concerns regarding steam hammer within the main steam line and identify the significant dynamic loads included in the main steam piping design.

- Design features that prevent water slug formations are included in the system design and layout. In the main steam system, these include the use of drain pots and the proper sloping of lines.

- The operating and maintenance procedures that protect against a potential occurrence of steam hammer include system operating procedures that provide for slowly heating up (to avoid condensate formation from hotter steam on colder surfaces), operating procedures that caution against fast closing of the main steam isolation valves except when necessary, and operating and maintenance procedures that emphasize proper draining.

- The stress analyses for the safety-related portion of the main steam system piping and components include the dynamic loads from rapid valve actuations, including actuation of the main steam isolation valves and the safety valves.

Based on the above discussion, water hammer does not have an adverse effect on the integrity of AP1000 leak-before-break piping systems.

3B.2.4 Fatigue

Low-Cycle Fatigue

Low-cycle fatigue due to normal operation and anticipated transients is accounted for in the design of the piping system. The Class 1 piping systems comply with the fatigue usage requirements of the ASME Code, Section III. The Class 2 and 3 piping systems comply with the stress range reduction factors of the ASME Code, Section III.

Due to the nature of operating parameters, main steam line piping (Class 2) and the Class 3 portion of the accumulator piping, are not subjected to any significant transients to cause low-cycle fatigue.

Based on the above discussion, low-cycle fatigue is not a concern of AP1000 leak-before-break piping systems.

High-Cycle Fatigue

High-cycle fatigue loads in the system result primarily from pump vibrations. The steam generator is designed so that flow-induced vibrations in the tubes are avoided (see subsection 5.4.2). The loads from reactor coolant pump vibrations are minimized by criteria for pump shaft vibrations during hot functional testing and operation. During operation, an alarm signals when the reactor coolant pump vibration is greater than the limits.

With these precautions taken, the likelihood of leakage due to fatigue in piping systems evaluated for leak-before-break is very small.

3B.2.5 Thermal Aging

Stainless Steel Piping

Piping used in the reactor coolant loop and other auxiliary lines are wrought stainless steel materials, rather than cast materials, so that thermal aging concerns are not expected for the AP1000 piping and fittings. The welds used in the assembly of the AP1000 are gas tungsten arc welds (GTAW). These welds are essentially as resistant to the effects of thermal aging as the base metal materials. This is due to the typically low ferrite contact in welds which results in minimal impact from thermal aging. Based on this information, thermal aging of weld materials and piping used in the AP1000 is not an issue.

Main Steam Lines

The main steam piping system does not have cast materials. The welding process used on these lines is also gas tungsten arc weld (GTAW).

There are no thermal aging concerns for the carbon steel piping of the main steam line and the alloy steel of the main feedwater piping.

The material used for the main steam piping system is not susceptible to dynamic strain aging effects.

3B.2.6 Thermal Stratification

Leak-before-break analyses include consideration of the loads and stresses due to thermal stratification.

Thermal stratification occurs only in a pipe that has a susceptible geometry and low flow velocities. A temperature difference between the flowing fluid and stagnant fluid is also a prerequisite.

The design of piping and component nozzles in the AP1000 includes provisions to minimize the potential for and the effects of thermal stratification, cycling, and striping, pursuant to actions requested in several NRC bulletins, as discussed below.

Primary Loop Piping

Thermal stratification in the reactor coolant loops resulting from actuation of passive safety features is evaluated as a design transient. Stratification effects due to both Level B and Level D service conditions are considered. The criteria used in the evaluation of the stress in the loop piping due to stratification is the same as that applicable for other Level B and Level D service conditions.

Auxiliary Stainless Steel Piping

Pursuant to the actions requested in NRC Bulletin 88-11, the pressurizer surge line is analyzed to demonstrate that the applicable requirements of the ASME Code, Section III are met. This analysis includes consideration of plant operation, thermal stratification, and thermal striping using temperature distributions and transients developed from experience on existing plant monitoring programs.

Pursuant to the actions requested in NRC Bulletin 88-08 (cracking in piping connected to reactor coolant systems due to isolation valve leakage), a systems review of the AP1000 piping was performed in accordance with the criteria provided in subsection 3.9.3.1.2.

The unisolable sections of the following lines which are evaluated for leak-before-break have been reviewed and are not susceptible to adverse stresses as described in NRC Bulletin 88-08:

Passive residual heat removal (PRHR) line from the hot leg, through the passive residual heat removal heat exchanger, and to the steam generator channel head
The potential for leakage through the isolation valves is not a concern for the piping extending from the reactor coolant system hot leg connection to the passive residual heat removal heat exchanger inlet, since hot leakage from the reactor coolant system would be entering a hot section of piping. Leakage exiting the passive residual heat removal heat exchanger would not be a concern since the cooled leakage would be entering a cold section of piping. This leakage would then heat up in the piping directly below the steam generator. Any amount of leakage is expected to be small, since the pressure differential across the isolation valves is about 50 psi (the difference between the hot leg and reactor coolant pump suction pressures). Activation of the passive residual heat removal system following a plant scram is not a concern, since stratification will not occur due to the high flow velocity in the passive residual heat removal return flow line.

Automatic depressurization stage 4 lines from the hot legs to the stage 4 depressurization valves
Leakage is not a concern since the squib valves are leaktight and other potential leakage flow paths have double isolation.

Pressurizer safety line from the pressurizer to the safety valve
This line is steam filled and will not experience stratified loadings.

Automatic depressurization stage 2 and 3 lines from the pressurizer to the depressurization valves
Leakage is not a concern since double isolation exists in all potential leakage flow paths.

Normal residual heat removal suction lines from the hot legs to the isolation valves
The piping from the hot legs to the isolation valves is expected to be essentially at the hot leg temperature during 100 percent power due to turbulent penetration and convective currents which heat the line. Isolation valve leakage is not a concern since hot leakage from the reactor coolant system would be entering a hot section of piping.

Main Steam Line

The steam lines are not subjected to thermal stratification by the nature of fluid transported.

Based on the above discussion, thermal stratification does not have an adverse effect on the integrity of AP1000 leak-before-break piping systems.

3B.2.7 Other Mechanisms

The pipe evaluated for leak-before-break does not operate at temperature for which creep fatigue must be considered. Creep fatigue is a concern for ferritic steel piping operation at temperatures above 700°F and for austenitic stainless steel operation above 800°F.

Pipe degradation or failure by indirect causes such as fires, missiles, and component support failures is precluded by criteria for design, fabrication, inspection, and separation of potential hazards in the vicinity of the safety-related piping. The structures, larger pipe, and components in the vicinity of pipe evaluated for leak-before-break are safety-related and seismically designed or are seismically supported if nonsafety-related.

Cleavage type failures are not a concern for systems operating temperature and material used in the stainless steel piping systems. The material used in the main steam line is highly ductile and resistant to cleavage type failure at operating temperatures. The resistance to failure have been demonstrated by material fracture toughness tests.

3B.3 Leak-Before-Break Bounding Analysis

The methodology used for performing the bounding analysis is consistent with that set forth in GDC-4, SRP 3.6.3 (Reference 1) and NUREG-1061, Volume 3 (Reference 2).

Bounding leak-before-break analysis for the applicable AP1000 piping systems is performed. The analysis criteria and development techniques of the bounding analysis curves (BAC) are described below. The bounding analysis curve allows for the evaluation of the piping system in advance of the final piping analysis, incorporating leak-before-break considerations early in the piping design process. The leak-before-break bounding analysis curve is used to evaluate critical points in the piping system. A minimum of two points are required to develop the bounding analysis curve. One point for the low normal stress case and the other point for the high normal stress case. If variations in pipe size, material, pressure or temperature occur for a specific piping system, an additional bounding analysis curve is generated. These points meet the following margins for leak-before-break analysis: (References 1 and 2).

- Margin of 10 on leak detection capability
- Margin of 2 on flaw size
- Establish margin of 1 on load by using absolute combination method of maximum loads

The calculations to establish the bounding analysis curves use minimum values for wall thickness at the weld counterbore and ASME Code material properties. For the main steam line lower bound material property values determined from tests of the material are used. The use of the minimum values bounds the results of larger values. Since the piping is designed and analyzed

using ASME Code minimum material properties, these are used conservatively in a consistent manner for evaluation of leak-before-break evaluations. The as-built material properties are expected to be higher than the ASME Code minimum properties. Using minimum thickness instead of a nominal thickness is conservative for the stability analysis and was also used for leak-before-break in operating plants. The use of one thickness (either nominal or minimum) for both leak rate and stability calculation gives comparable overall margins for typical plant loads. The bounding analysis curves are established using the axial load from internal pressure and neglecting other axial loads. This is an appropriate approximation because experience with leak-before-break calculations has shown that the axial load due to pressure is the dominant axial load.

3B.3.1 Procedure for Stainless Steel Piping

3B.3.1.1 Pipe Geometry, Material and Operating Conditions

The following information is identified for each of the lines:

- Piping materials - 316LN/304L, Type 304L is used for the accumulator discharge line
- Normal operating temperature
- Normal operating pressure
- Pipe outside diameter
- Pipe thickness

The number of bounding analysis curves needed for each analyzable piping system is determined by a review of the combinations of the following parameters:

– Pipe size
– Pipe schedule
– Operating pressures (100 percent power and maximum stress condition)
– Operating temperatures (100 percent power and maximum stress condition)

3B.3.1.2 Pipe Physical Properties

The physical and metallurgical properties for each of the lines are determined in the following manner

- Minimum wall thickness is calculated at the weld counterbore

- The area (A) and section modulus (Z) are calculated using minimum wall thickness

- The yield strength is the ASME Code, Section II (Reference 5) minimum value, at temperature of interest

- The ultimate strength is the ASME Code, Section II (Reference 5) minimum value, at temperature of interest

- The modulus of elasticity is the ASME Code, Section II (Reference 5) at temperature of interest

3B.3.1.3 Low Normal Stress Case (Case 1)

To determine the first point of the bounding analysis curve the following steps are used.

- Calculate axial force Fp (for normal operating pressure)
- Assume a lower magnitude of bending stress. The magnitude selected is a very small number that is lower than the expected minimum bending stress.
- Calculate bending moment = (bending stress) x (section modulus)
- Calculate the leakage flaw size at 100 percent power condition for 10 times the leak detection capability (for 0.5 gpm leak detection capability, this is 10 x 0.5 = 5 gpm)
- Perform the stability analysis using the limit load methodology to obtain the critical flaw size. For AP1000 piping systems, there is no cast material and the weld process is gas tungsten arc welds (Z factor is 1.0 since weld process is gas tungsten arc welds, Reference 1.)
  - Determine the maximum loads for a critical flaw size of twice the leakage flaw size. The margin of 2 on flaw size is satisfied.
- Calculate the low normal stress and corresponding maximum stress by using:

$$\text{Stress} = \frac{\text{Axial Force}}{\text{Area}} + \frac{\text{Bending Moment}}{\text{Section Modulus}} \qquad \text{(3B-1)}$$

3B.3.1.4 High Normal Stress Case (Case 2)

To determine the other endpoint of the bounding analysis curve the following steps are used.

- Axial force Fp is calculated as above for normal operating pressure
- Assume a higher magnitude of bending stress to get higher bending moment. The magnitude of bending is selected such that the corresponding maximum stress generated is close to the flow stress.
- Calculate bending moment = (bending stress) x (section modulus)
- Repeat leakage flaw size and stability calculations as outlined for the low normal stress case above

Note: For an intermediate point, calculation steps are the same as low normal or the high normal case.

3B.3.1.5 Develop the Bounding Analysis Curve

- For Case 1, normal and maximum stresses are established.

- For Case 2, normal and maximum stresses are established.

- Plot these two points with normal versus maximum stress. The curve is generated by joining these two points in a straight line. More than two points may be used if desired, to obtain a smooth curve fit between the calculated points. A typical curve is shown in Figure 3B-1.

3B.3.2 Procedure for Non-Stainless Steel Piping

The procedure to develop the bounding analysis curve for the carbon steel for main steam lines is similar to that for the stainless steel and is described below.

3B.3.2.1 Pipe Geometry, Material and Operating Conditions

The following information is identified for each of the lines:

- Piping materials
- Normal operating temperature
- Normal operating pressure
- Pipe outside diameter
- Piping thickness

The number of bounding analysis curves needed for each analyzable piping system is determined by a review of the combinations of the following parameters:

- Pipe size
- Pipe schedule
- Operating pressures (100 percent power and maximum stress condition)
- Operating temperatures (100 percent power and maximum stress condition)

3B.3.2.2 Calculations Steps

- The minimum wall thickness is calculated at the weld counterbore

- The area (A) and section modulus (Z) are calculated using minimum wall thickness

- The material yield strength, ultimate strength, modulus of elasticity, stress-strain curves, and J-R curves are determined from the material tests

3B.3.2.3 Low Normal Stress Case (Case 1)

To determine the first point of the bounding analysis curve the following steps are used.

- Calculate axial force Fp (for normal operating pressure)
- Assume a lower magnitude of bending stress
- Calculate bending moment = (bending stress) x (section modulus)
- Calculate the leakage flaw size at 100 percent power condition for 10 times the leak detection capability (for 0.5 gpm leak detection capability, this is 10 x 0.5 = 5 gpm)
- Stability analysis
  - Perform J-integral analysis
  - Determine the maximum loads for a critical flaw size of twice the leakage flaw size by satisfying the stability criteria. The margin of 2 on flaw size is satisfied.
- Stability criteria
  - $J_{applied} \leq J_{IC}$
  - If $J_{applied} > J_{IC}$, then $J_{applied} < J_{max}$ and $T_{applied} < T_{mat}$
- Calculate the low normal stress and corresponding maximum stress by using:

$$\text{Stress} = \frac{\text{Axial Force}}{\text{Area}} + \frac{\text{Bending Moment}}{\text{Section Modulus}}$$

3B.3.2.4 High Normal Stress Case (Case 2)

To determine the other endpoint of the bounding analysis curve the following steps are used.

- Axial force Fp is calculated above (for normal operating pressure)
- Assume a higher magnitude of bending stress to get higher bending moment
- Calculate bending moment = (bending stress) x (section modulus)
- Repeat leakage flaw size and stability calculations as outlined for the low normal stress case above

Note: For an intermediate point, calculation steps are the same as low normal or the high normal case.

3B.3.2.5 Develop the Bounding Analysis Curve

Follow steps as outlined for the stainless steel case in subsection 3B.3.1.5.

3B.3.3 Evaluation of Piping System Using Bounding Analysis Curves

To evaluate the applicability of leak-before-break, the results of the pipe stress analysis are compared to the bounding analysis curve. The critical location is the location of highest maximum stress as determined by the pipe stress results. A comparison is made with the applicable bounding analysis curves for the analyzable piping systems. As outlined in 3B.3.1.1 and 3B.3.2.1, bounding analysis curves are calculated for different combinations of pipe size, pipe schedule, operating pressures, operating temperatures.

The bounding analysis curves are used during the layout and design of the piping systems to provide a design that satisfies leak-before-break criteria. In addition, the Combined License holder compares the results of the as-built piping analysis reconciliation to the bounding analysis curves to verify that the fabricated piping systems satisfy leak-before-break criteria. See subsection 3.6.4 for the Combined License information item associated with this verification.

At the critical location, the load combination for the maximum stress calculation uses the absolute sum method. The load combination is as follows:

(1) $|\text{Pressure}| + |\text{Deadweight}| + |\text{Thermal (100\% Power)*}| + |\text{Safe Shutdown Earthquake}|$

The normal stress is calculated using the algebraic sum method at critical location and the following load combination.

(1) Pressure + Deadweight + Thermal (100% Power*)

* Includes applicable stratification loads.

3B.3.3.1 Calculation of Stresses

The stresses due to axial loads and moments are calculated by the following equation:

where:

$$\sigma = \frac{F}{A} + \frac{M}{Z} \qquad \text{(3B-2)}$$

σ	=	stress
F	=	axial load
M	=	moment
A	=	cross-sectional area
Z	=	section modulus

The moments for the desired loading combinations are calculated by the following equation:

$$M = \sqrt{M_X^2 + M_Y^2 + M_Z^2} \tag{3B-3}$$

where,

M = moment for required loading
M_X = torsional moment
M_Y = Y component of bending moment
M_Z = Z component of bending moment
The Y and Z-axes are lateral axes to the X-axis which is the axial axis

The axial load and moments for the normal case and maximum case are computed by the methods shown below.

3B.3.3.2 Normal Loads

The normal operating loads are calculated by the following equations:

$$F = F_{DW} + F_{Th} + F_P \tag{3B-4}$$

$$M_X = (M_X)_{DW} + (M_X)_{Th} \tag{3B-5}$$

$$M_Y = (M_Y)_{DW} + (M_Y)_{Th} \tag{3B-6}$$

$$M_Z = (M_Z)_{DW} + (M_Z)_{Th} \tag{3B-7}$$

The subscripts of the above equations represent the following load cases:

DW = deadweight

Th = normal thermal expansion (100 percent power, including applicable stratification loads)

P = load due to internal pressure

The method of combining loads is often referred to as the algebraic sum method.

Calculate the normal stress at the critical location.

3B.3.3.3 Maximum Loads

For the maximum case, the absolute summation method of load combination is applied which results in higher magnitude of the combined loads. Since stability is demonstrated using these loads, the leak-before-break margin on loads is satisfied. An example of the absolute summation expressions are shown below:

$$F = |F_{DW}| + |F_{Th}| + |F_P| + |F_{SSEINERTIA}| + |F_{SSEAM}| \tag{3B-8}$$

$$M_X = |(M_X)_{DW}| + |(M_X)_{Th}| + |(M_X)_{SSEINERTIA}| + |(M_X)_{SSEAM}| \quad (3B\text{-}9)$$

$$M_Y = |(M_Y)_{DW}| + |(M_Y)_{Th}| + |(M_Y)_{SSEINERTIA}| + |(M_Y)_{SSEAM}| \quad (3B\text{-}10)$$

$$M_Z = |(M_Z)_{DW}| + |(M_Z)_{Th}| + |(M_Z)_{SSEINERTIA}| + |(M_Z)_{SSEAM}| \quad (3B\text{-}11)$$

where subscripts SSE, Inertia and AM mean safe shutdown earthquake, inertia and anchor motion respectively.

3B.3.3.4 Bounding Analysis Curve Comparison – LBB Criteria

To compare the stress results with the bounding analysis curve the following process is followed. The normal and maximum stress at the critical location are calculated by using the loads defined in subsection 3B.3.3. Plot the normal stress versus maximum stress on the bounding analysis curve for the specified system. If the point is on or below the bounding analysis curve, the leak-before-break analysis and margins are satisfied. If the point falls above the bounding analysis curve, the leak-before-break analysis criteria are not satisfied and the pipe layout or support configuration needs to be revised to meet the leak-before-break bounding analysis. Figure 3B-1 shows a typical bounding analysis curve.

3B.3.4 Bounding Analysis Results

Table 3B-1 shows a summary of piping systems and corresponding bounding analysis figures. Figures 3B-1 to 3B-21 show the bounding analysis curves. The curves satisfy the margins as indicated in subsection 3B.3.

3B.4 Differences in Leak-Before-Break Analysis for Stainless Steel and Ferritic Steel Pipe

The significant difference between leak-before-break analysis performed for the stainless steel (Class 1 and Class 3) systems and the ferritic steel in the Class 2 systems is in the stability analysis. In the case of stainless steel systems, stability analyses are performed by limit load approach. In the ferritic steel systems, stability analyses are performed by J-integral approach.

3B.5 Differences in Inspection Criteria for Class 1, 2, and 3 Systems

Class 1, 2 and 3 systems are subjected to in-service inspection requirements from ASME Code, Section XI. For Class 1 piping, terminal ends and dissimilar metal welds are volumetrically inspected, along with other locations, to total 25 percent of the welds. For Class 2 piping, the requirement is to volumetrically inspect the terminal ends and other locations to total 7.5 percent of the welds. For Class 3 systems (the only Class 3 piping is in the accumulator line which is always at room temperature), the system receives periodic visual examinations in conjunction with pressure testing. These requirements were developed by ASME Code, Section XI consistent with the different safety classes of these systems.

The leak-before-break evaluations are based on the ability to detect a potential leaking crack; not the ability to find cracks by inservice inspections. The criteria or methods of the leak-before-break evaluations are the same for ASME Code Class 1, 2, and 3.

3B.6 Differences in Fabrication Requirements of ASME Class 1, Class 2, and Class 3 Piping

The significant difference among Class 1, 2 and 3 seamless pipe occurs in the nondestructive examination requirements. The Class 1 seamless pipe examination requirements include an ultrasonic testing examination, whereas Class 2 and 3 do not. In addition, the Class 1 examination requirements for a circumferential butt welded joint include radioagraphic testing and magnetic particle or liquid penetrant examination where Class 2 does not. The examination requirements for Class 2 pipe require radiographic examination of the welds and normally Class 3 pipe does not. As noted in subsection 3.2.2.5, for Class 3 lines required for emergency core cooling functions, radiography will be conducted on a random sample of welds. The Class 3 leak-before-break lines are included in the lines that are radiographed. In addition see subsection 3.6.3.2 for augmented inspection of Class 3 leak-before-break lines.

For the fabrication of welds in the Class 1, Class 2 and Class 3 pipes there is no significant differences.

The differences in fabrication and nondestructive examination requirements do not affect the leak-before-break analyses assumptions, criteria, or methods.

3B.7 Sensitivity Study for the Constraint Effect on LBB

Westinghouse performed a sensitivity study on a 6-inch diameter pipe to demonstrate that the leak-before-break evaluation margins are not significantly affected when constraint effects of pressure induced bending are included. The analysis used a finite element model of a 6-inch diameter pipe welded to a nozzle with a fixed end condition. This conservatively represents the bounding conditions for AP1000 piping. The normal and maximum stresses were used from a representative AP600 6-inch line bounding analysis curve. The material properties for the base metal and TIG weld were considered in the analysis. The stability analysis was performed using the J-integral method. This analysis was developed in consultation with the NRC.

The conclusion of this sensitivity study is that the leak-before-break margins for 6-inch and larger piping on AP1000 are not significantly affected by the constraint effect and application of leak-before-break to such piping is acceptable.

3B.8 References

1. Standard Review Plan 3.6.3, "Leak Before Break Evaluation Procedures," Federal Register, Volume 52, Number 167, Friday, August 28, 1987; Notice (Public Comment Solicited), pp. 32626-32633.

2. NUREG-1061, "Evaluation of Potential for Pipe Breaks, Report of the U.S. Nuclear Regulatory Commission Piping Review Committee," Volume 3, (prepared by the Pipe Break Task Group), November 1984.

3. "Erosion-Corrosion in Nuclear Plant Steam Piping: Causes and Inspection Program Guidelines," EPRI NP-3944, April 1985.

4. G. Cragnolino, "Erosion-Corrosion in Nuclear Power Systems-An Overview," Corrosion '87, Paper No. 86, March 1987.

5. ASME Boiler and Pressure Vessel Code, Section II, "Materials," 2001 Edition, July 1, 2001.

Table 3B-1 (Sheet 1 of 2)

AP1000 LEAK-BEFORE-BREAK BOUNDING ANALYSIS SYSTEMS AND PARAMETERS

System	Subsystem	Line No(s).	Nominal Diameter (Inches)	Material	Temp (°F)	Pressure (psig)	Figure No.
RCS	Primary Loop Hot Leg	L001A, B	31	SA-376 TP316LN	610.0	2248	3B-2
RCS	Primary Loop Cold Leg	L002A, B, C, D	22	SA-376 TP316LN	537.2	2310	3B-3
SGS	Main Steam Line	L006A, B	38	SA-333 GR6	523.0	821	3B-4
RCS	Normal Residual Heat Removal	L139	20	SA-312 TP316LN	610.0	2248	3B-5
RCS	Surge Line	L003	18	SA-312 TP316LN	653.0	2248	3B-6 (Sheet 1)
RCS	Surge Line	L003	18	SA-312 TP316LN	455.0	430	3B-6 (Sheet 2)
RCS	Passive Residual Heat Removal Supply/ADS 4	L135A,B; L136A,B	18	SA-312 TP316LN	610.0	2248	3B-7
RCS	Passive Removal Heat Removal Supply/ADS 4	L133A, B; L137A, B; L134	14	SA-312 TP316LN	610.0	2248	3B-8
PXS	Passive Residual Heat Removal Supply to Cold Trap	L102	14	SA-312 TP316LN	610.0	2248	3B-8
PXS	Passive Residual Heat Removal Supply after Cold Trap to PRHR HX	L102	14	SA-312 TP316LN	120.0	2248	3B-9
PXS	Return – PRHR HX to Isolation Valve	L103; L104A, B	14	SA-312 TP316LN	120.0	2248	3B-9
RCS	Automatic Depressurization System Stage 2, 3	L004A,B; L006A,B; L020A,B; L030A, B; L131	14	SA-312 TP316LN	653.0	2235	3B-10

Table 3B-1 (Sheet 2 of 2)

AP1000 LEAK-BEFORE-BREAK BOUNDING ANALYSIS SYSTEMS AND PARAMETERS

System	Subsystem	Line No(s).	Nominal Diameter (Inches)	Material	Temp (°F)	Pressure (psig)	Figure No.
PXS	Passive Residual Heat Removal Return – after Isolation Valve	L104A, B; L105	14	SA-312 TP316LN	537.0	2190	3B-11
RCS	Passive Residual Heat Removal Return	L113	14	SA-312 TP316LN	537.0	2190	3B-11
PXS	Passive Residual Heat Removal Vent Line	L107	12	SA-312 TP316LN	610.0	2248	3B-12
PXS	Accumulator to Isolation Valve	L029A, B	8	SA-312 TP304L	120.0	700	3B-13
RCS	Balance Line from Cold Leg to CMT Isolation Valve	L118A, B	8	SA-312 TP316LN	537.0	2310	3B-14
PXS	Balance Line from CMT Isolation Valve to CMT	L007A, B; L070A, B	8	SA-312 TP316LN	537.0	2310	3B-14
PXS	Direct Vessel Injection Line to RV	L021A, B	8	SA-312 TP316LN	537.0	2310	3B-14
PXS	Core Makeup Tank (Injection Line, RV Side of Isolation Valve, Core Makeup Tank Side of Isolation Valve), Direct Vessel Injection (Accumulator Connection to Cold Trap), IWRST Injection	L015, L016, L017, L018, L020, L021, L025, L125, L127 (All A, B)	8	SA-312 TP316LN	120.0	2310	3B-15
RCS	Automatic Depressurization System Stage 2, 3	L021A,B; L031A,B	8	SA-312 TP316LN	653.0	2235	3B-16
PXS	Accumulator after Isolation Valve	L027A, B	8	SA-312 TP304L	120.0	700	3B-17
PXS	RNS Discharge	L019A, B	6	SA-312 TP316LN	120.0	2310	3B-18
RCS	Automatic Depressurization System Header to RCS Safety Valve	L005A, B	6	SA-312 TP316LN	653.0	2235	3B-19
RCS	Normal Residual Heat Removal	L140	12	SA-312 TP316LN	610.0	2248	3B-20
RNS	Normal Residual Heat Removal	L001, L002A, B	10	SA-312 TP316LN	610.0	2248	38-21

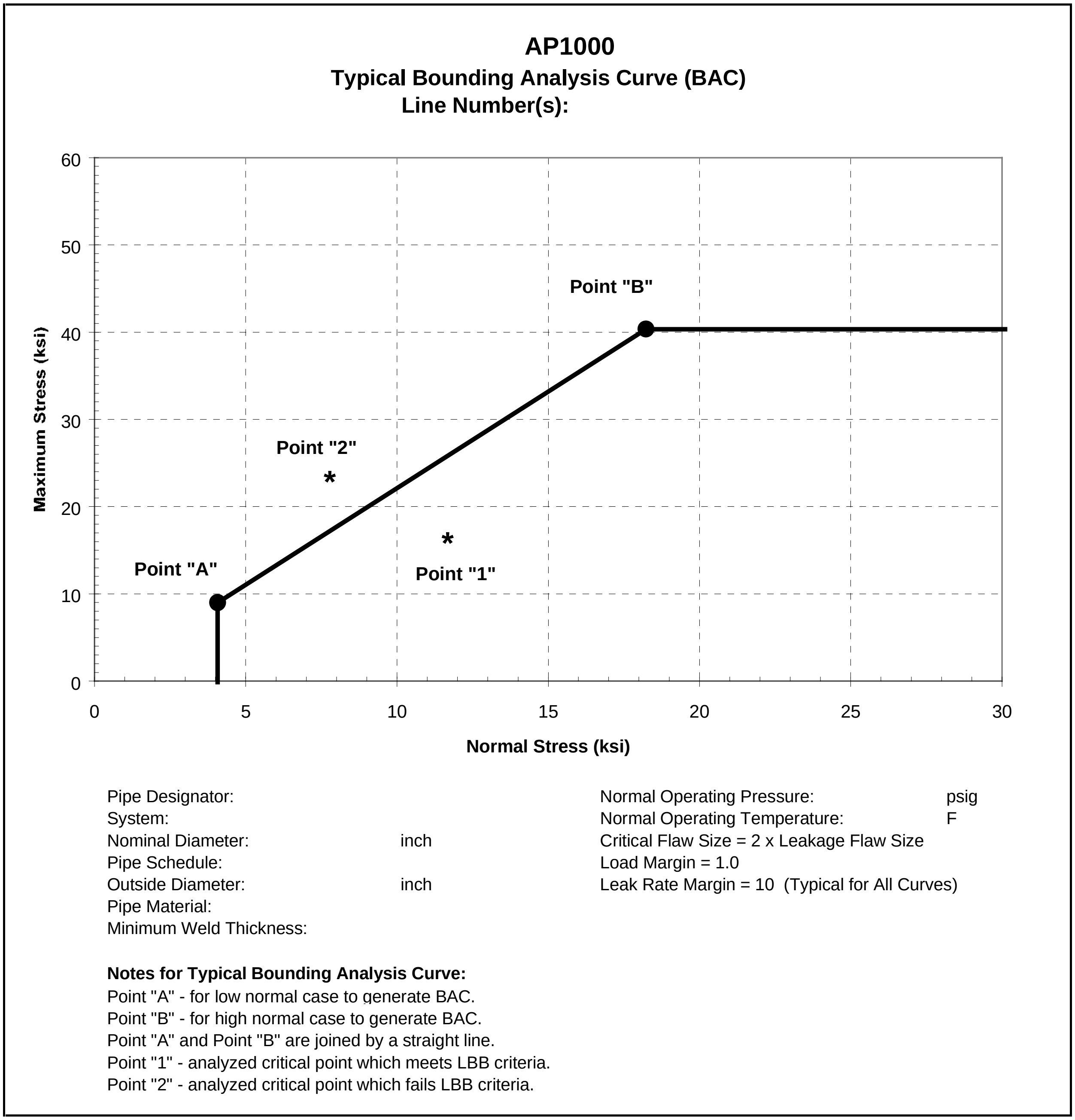
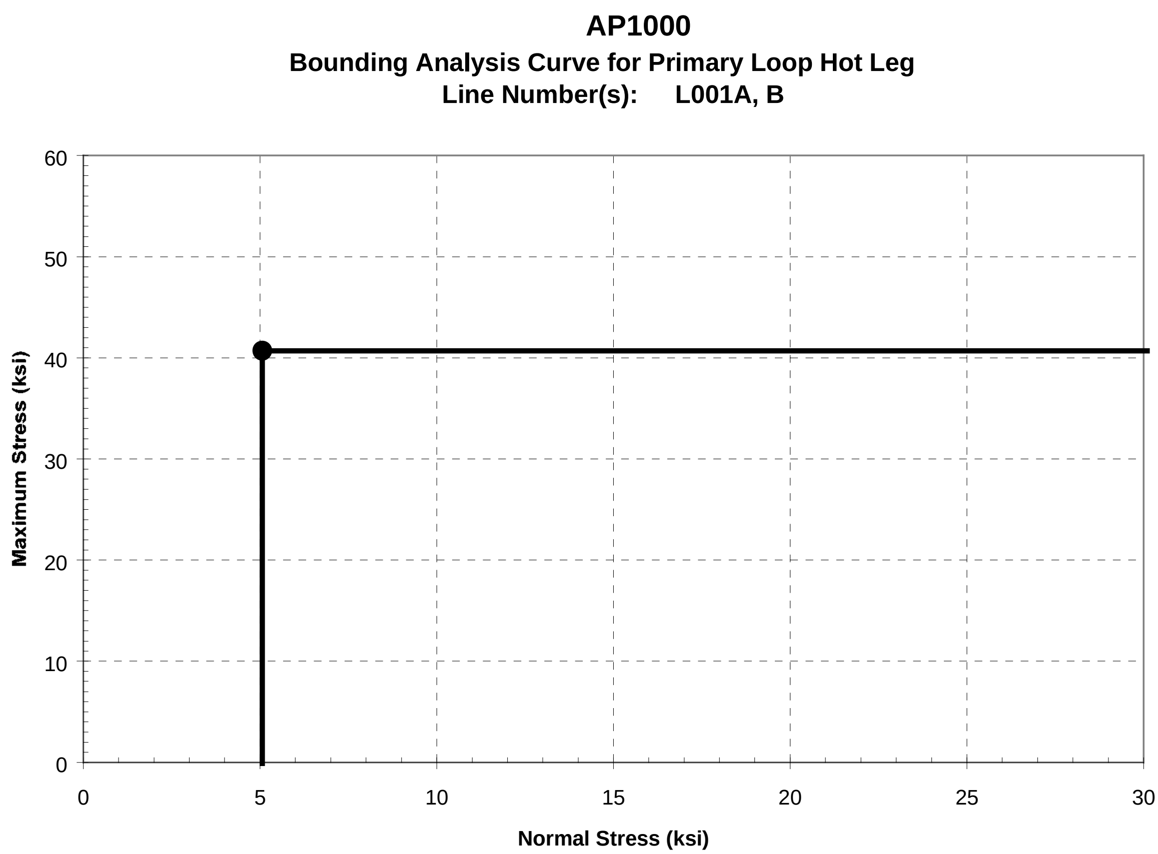


Figure 3B-1

Typical Bounding Analysis Curve (BAC)



Pipe Designator: BTA
System: RCS
Nominal Diameter: 31 inch
Pipe Schedule: Special
Outside Diameter: 37.500 inch
Pipe Material: SA-376 TP316LN
Minimum Weld Thickness: 3.145 inch

Normal Operating Pressure: 2248.0 psig
Normal Operating Temperature: 610.0 F
Critical Flaw Size = 2 x Leakage Flaw Size
Load Margin = 1.0

Figure 3B-2

Bounding Analysis Curve for Primary Loop Hot Leg

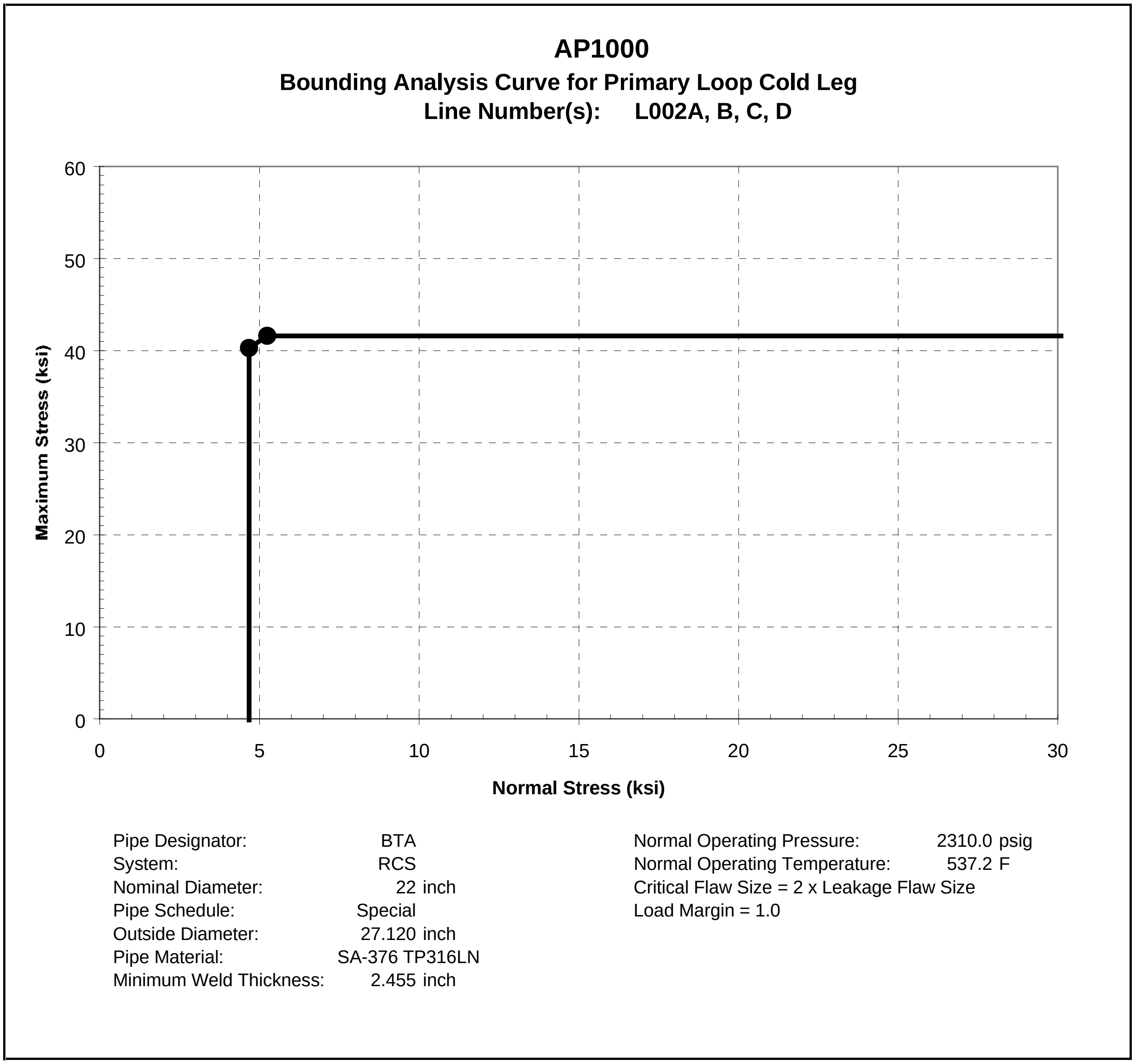


Figure 3B-3

Bounding Analysis Curve for Primary Loop Cold Leg

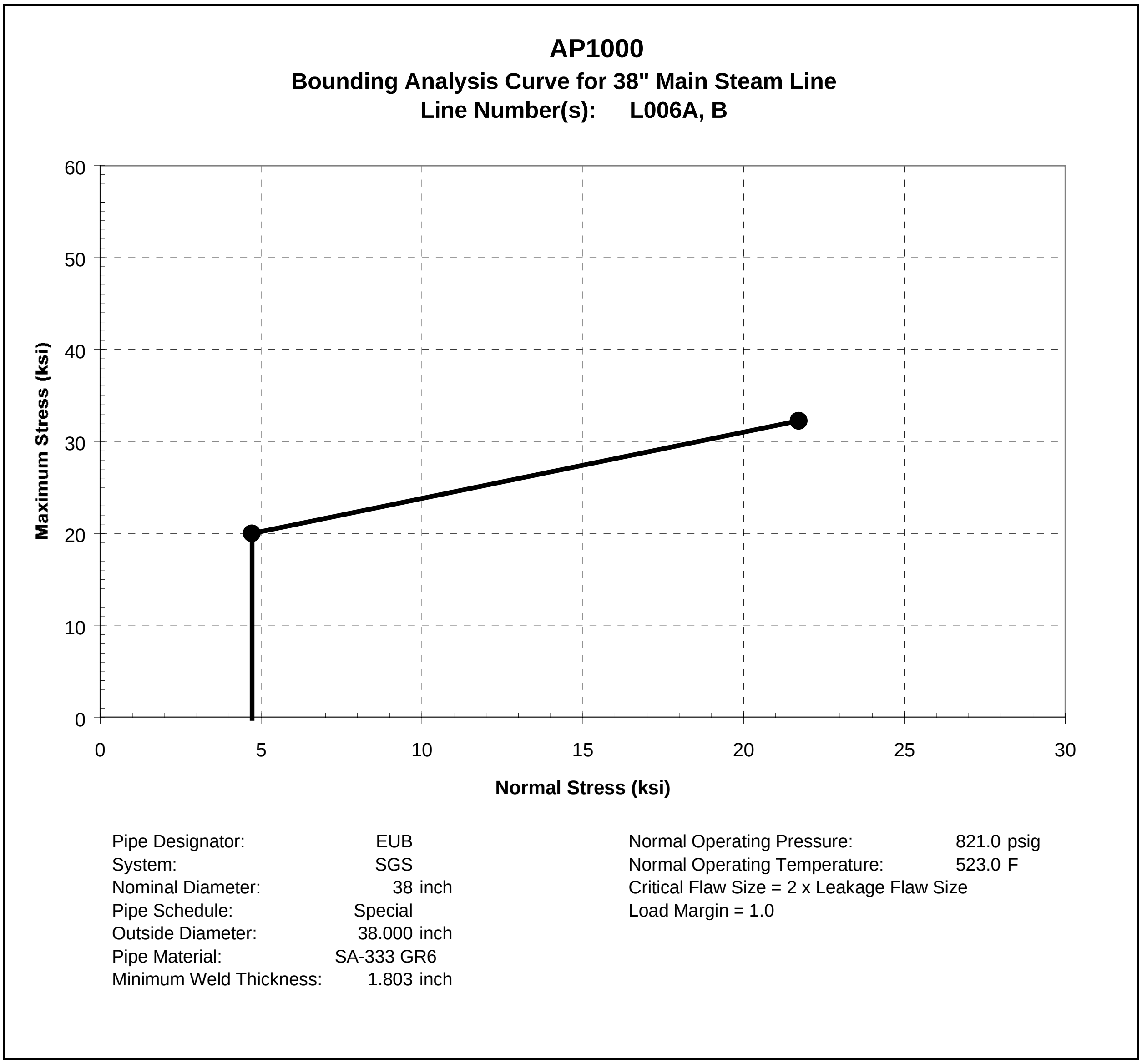


Figure 3B-4

Bounding Analysis Curve for 38″ Main Steam Line

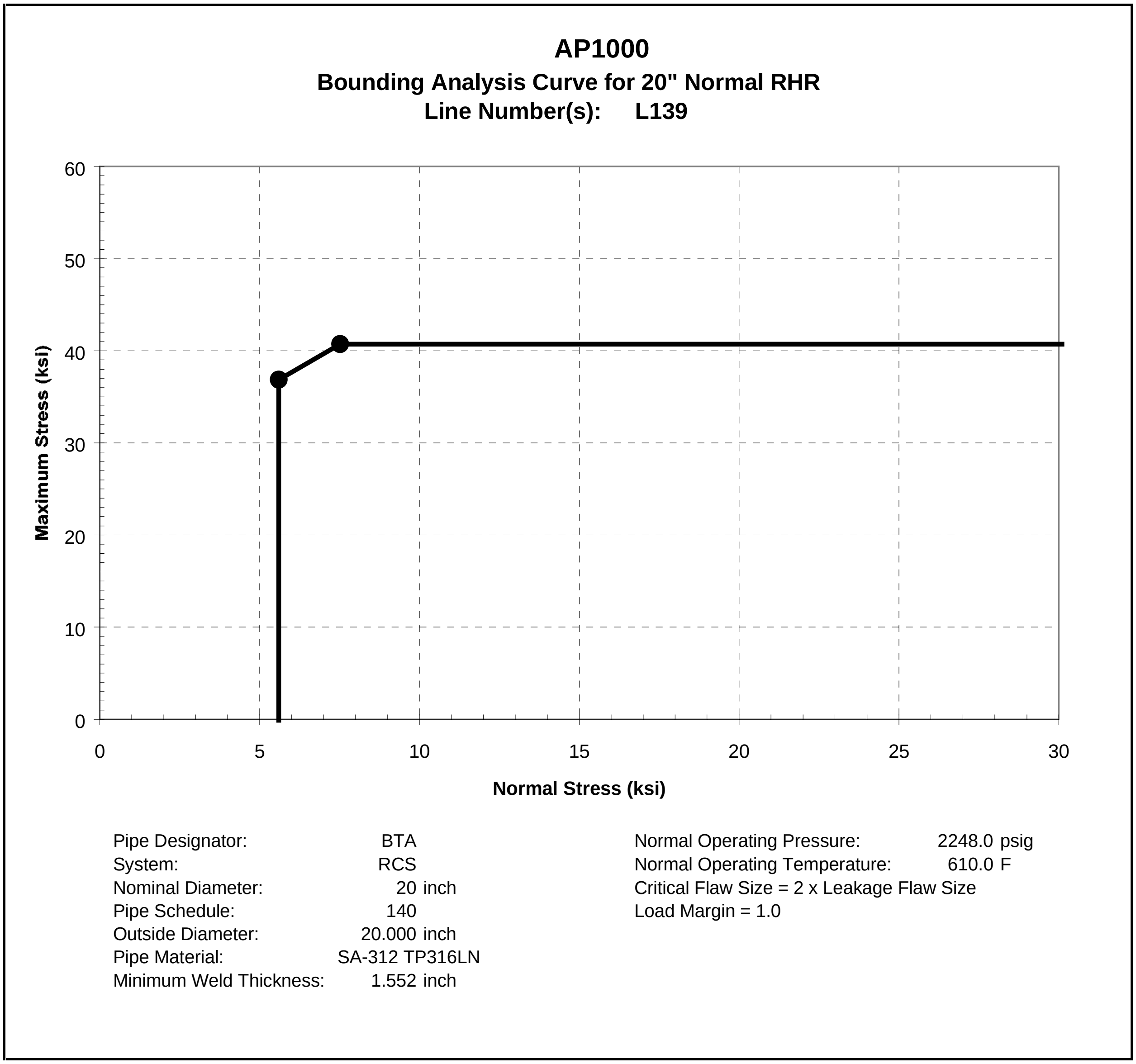
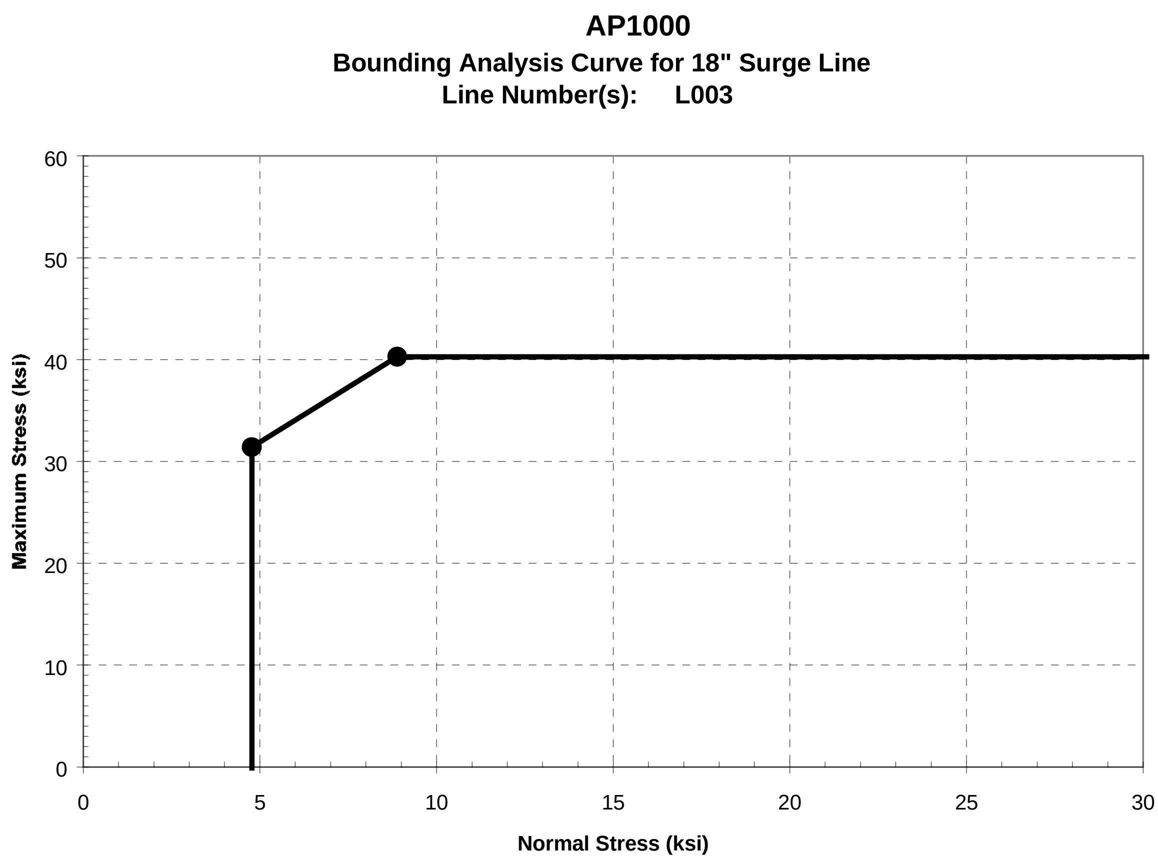


Figure 3B-5

Bounding Analysis Curve for 20″ Normal RHR



Pipe Designator:	BTA	Normal Operating Pressure:	2248.0 psig
System:	RCS	Normal Operating Temperature:	653.0 F
Nominal Diameter:	18 inch	Critical Flaw Size = 2 x Leakage Flaw Size	
Pipe Schedule:	160	Load Margin = 1.0	
Outside Diameter:	18.000 inch		
Pipe Material:	SA-312 TP316LN		
Minimum Weld Thickness:	1.579 inch		

Figure 3B-6 (Sheet 1 of 2)

Bounding Analysis Curve for 18″ Surge Line

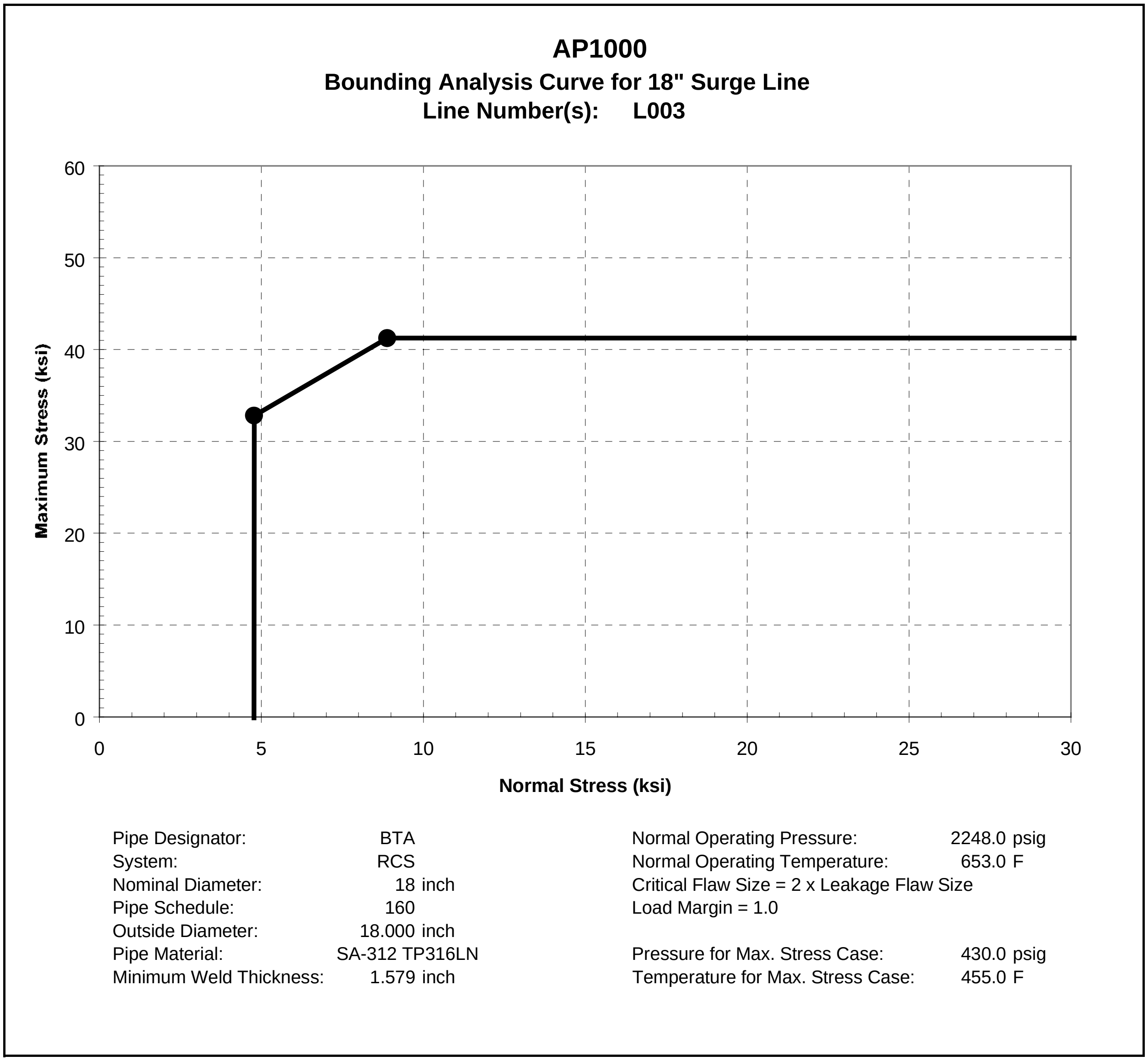


Figure 3B-6 (Sheet 2 of 2)

Bounding Analysis Curve for 18″ Surge Line

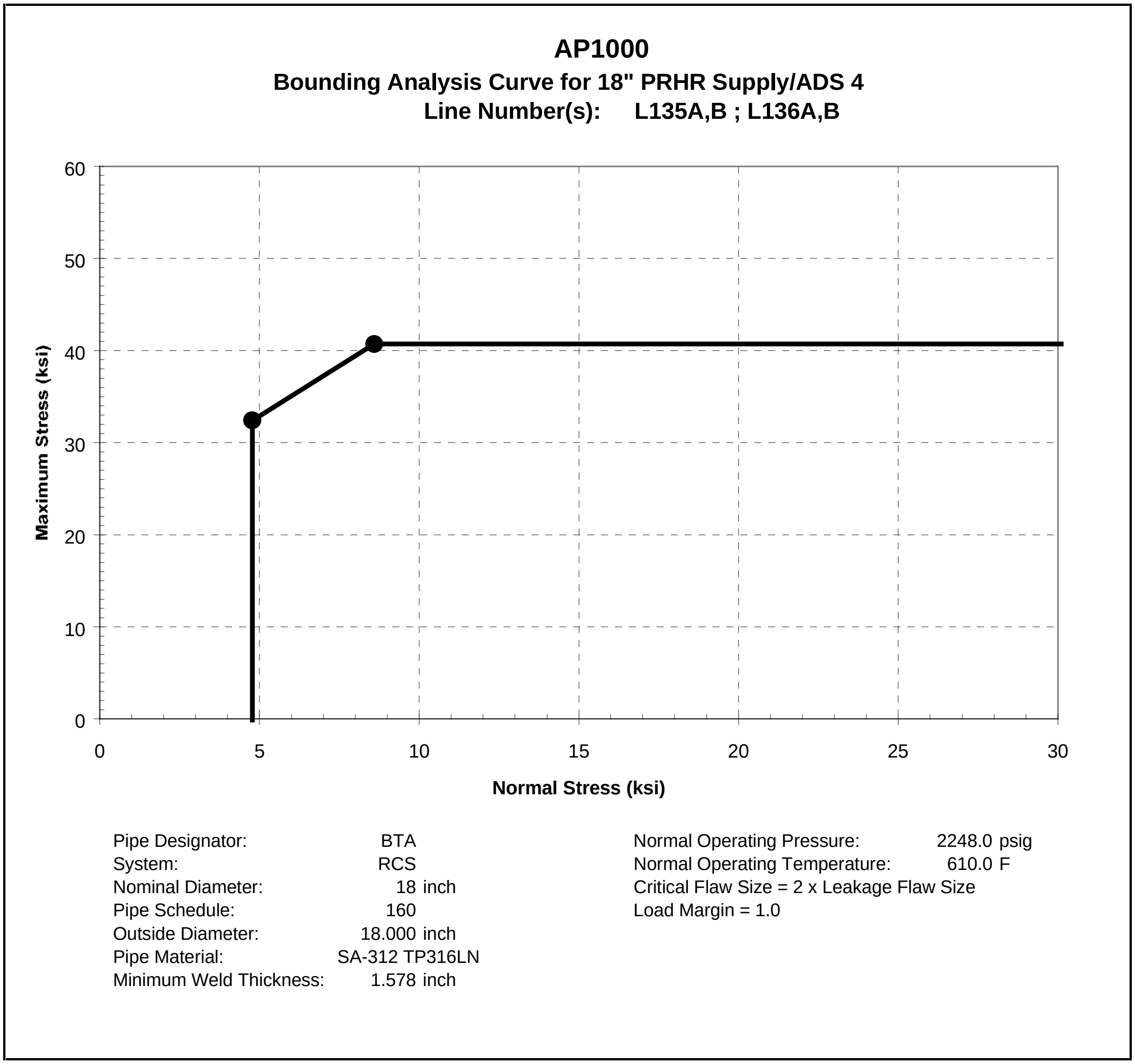


Figure 3B-7

Bounding Analysis Curve for 18″ PRHR Supply/ADS 4

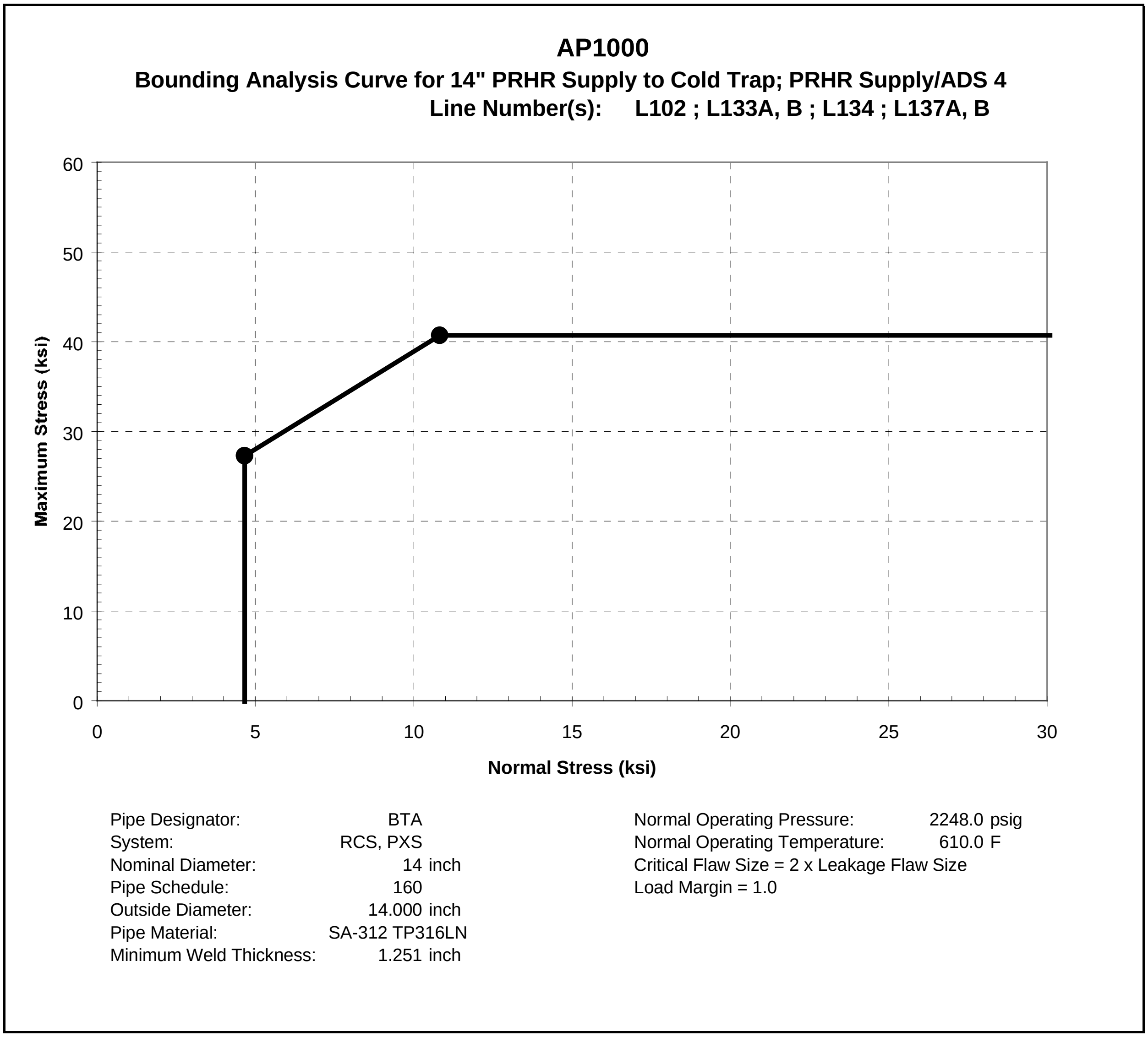
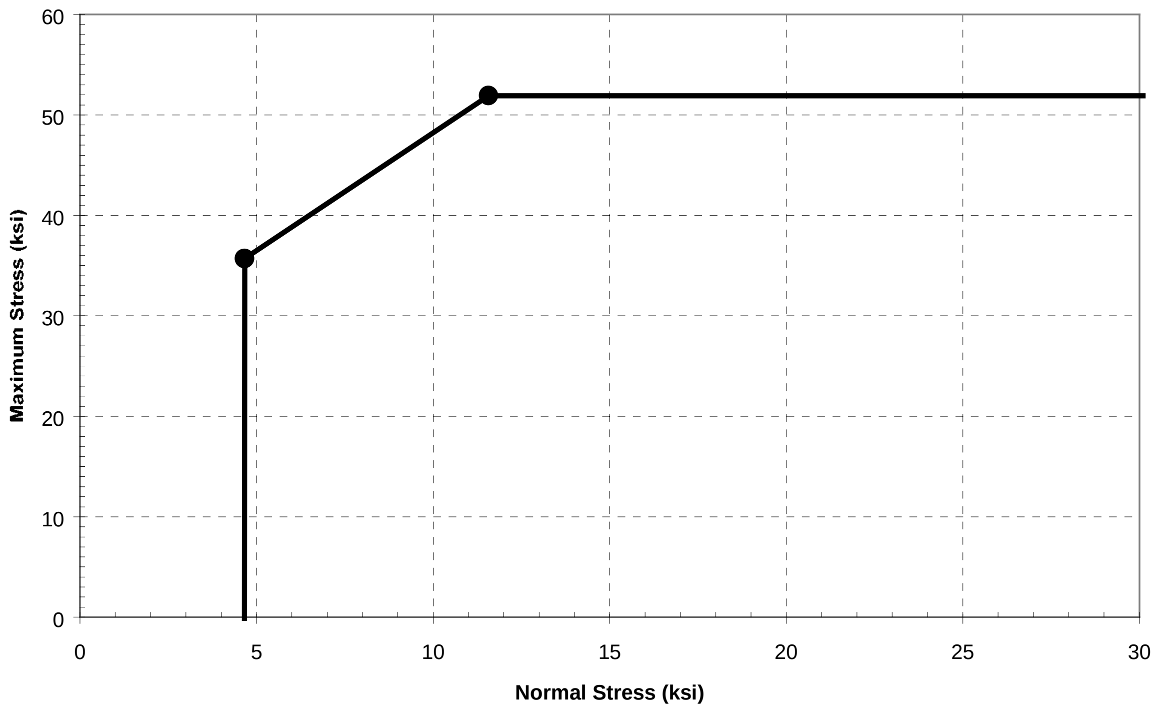


Figure 3B-8

Bounding Analysis Curve for 14″ PRHR Supply to Cold Trap, PRHR Supply/ADS4

AP1000
Bounding Analysis Curve for 14" PRHR Supply after Cold Trap, Return - to Isolation Valve
Line Number(s): L102 ; L103 ; L104A, B



Pipe Designator:	BTA	Normal Operating Pressure:	2248.0 psig
System:	RCS, PXS	Normal Operating Temperature:	120.0 F
Nominal Diameter:	14 inch	Critical Flaw Size = 2 x Leakage Flaw Size	
Pipe Schedule:	160	Load Margin = 1.0	
Outside Diameter:	14.000 inch		
Pipe Material:	SA-312 TP316LN		
Minimum Weld Thickness:	1.251 inch		

Figure 3B-9

Bounding Analysis Curve for 14″ PRHR Supply after Cold Trap, Return – to Isolation Valve

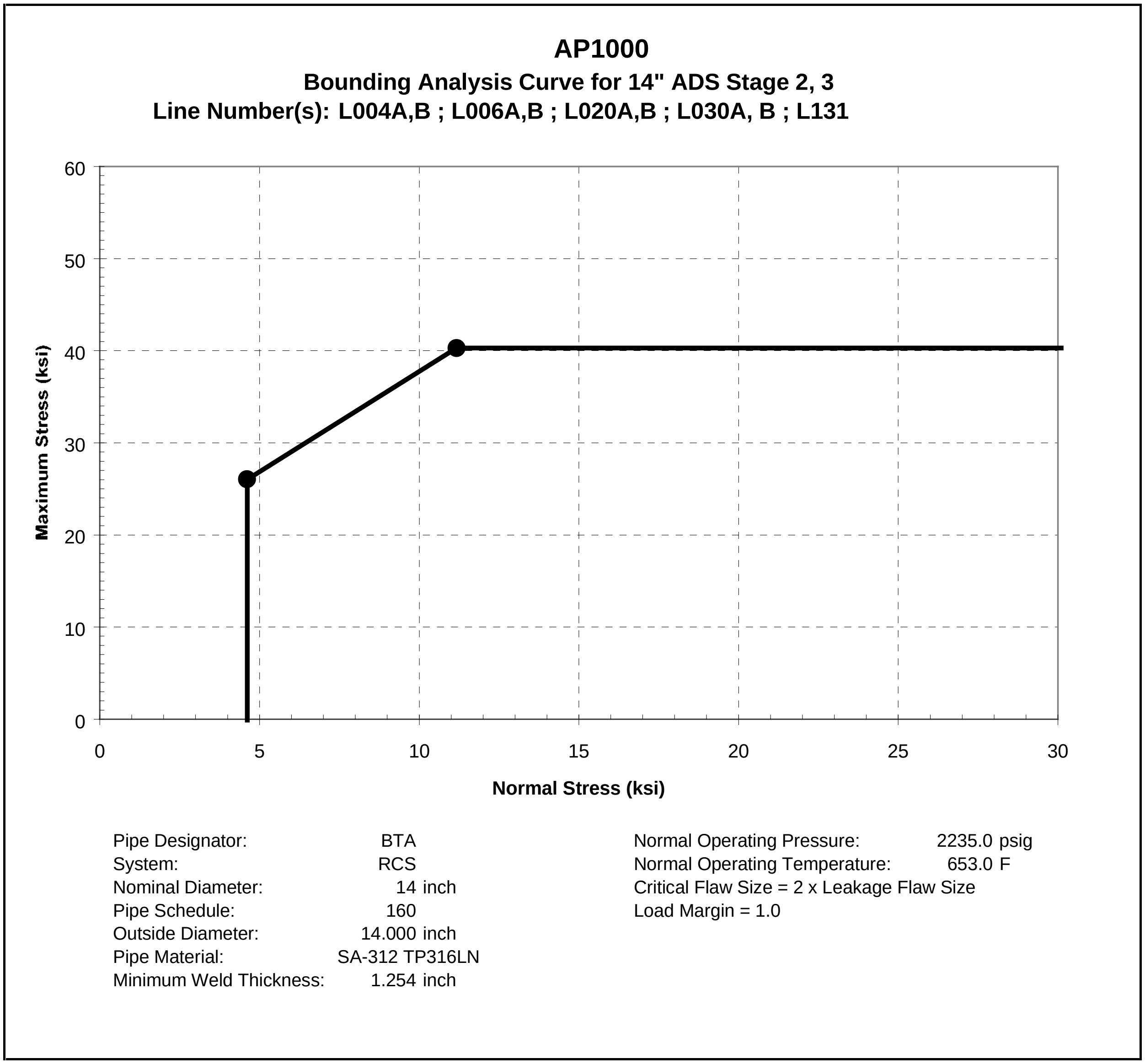
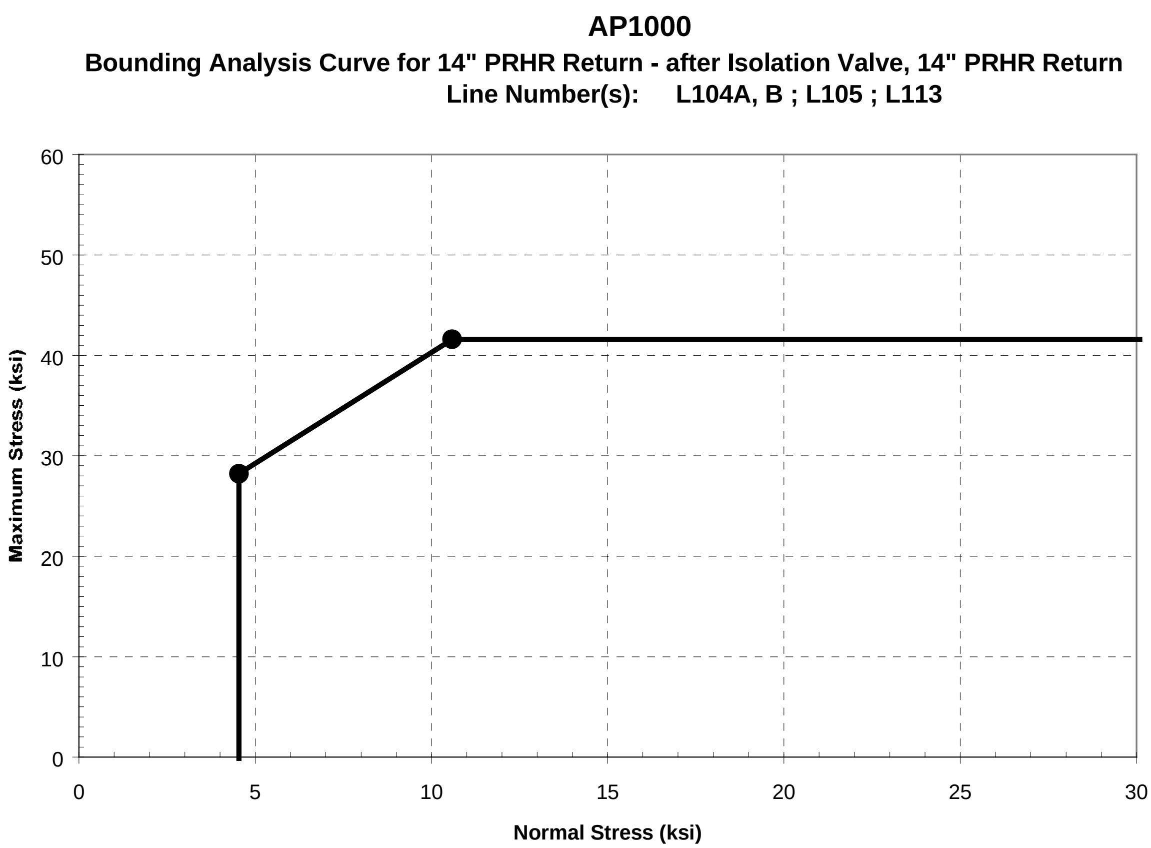


Figure 3B-10

Bounding Analysis Curve for 14″ ADS Stage 2, 3



Pipe Designator:	BTA	Normal Operating Pressure:	2190.0 psig
System:	RCS, PXS	Normal Operating Temperature:	537.0 F
Nominal Diameter:	14 inch	Critical Flaw Size = 2 x Leakage Flaw Size	
Pipe Schedule:	160	Load Margin = 1.0	
Outside Diameter:	14.000 inch		
Pipe Material:	SA-312 TP316LN		
Minimum Weld Thickness:	1.251 inch		

Figure 3B-11

Bounding Analysis Curve for 14″ PRHR Return – after Isolation Valve, 14″ PRHR Return

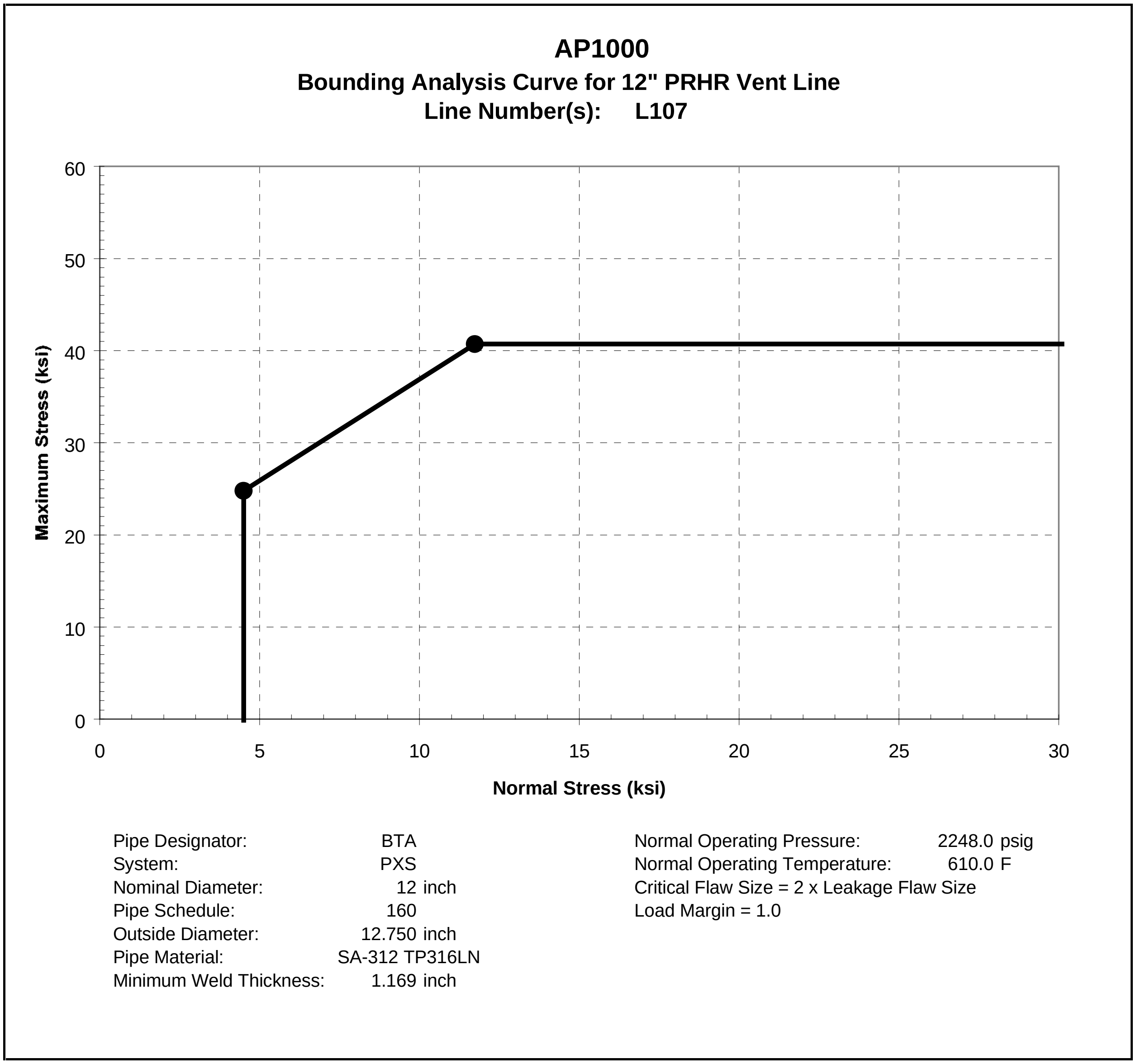
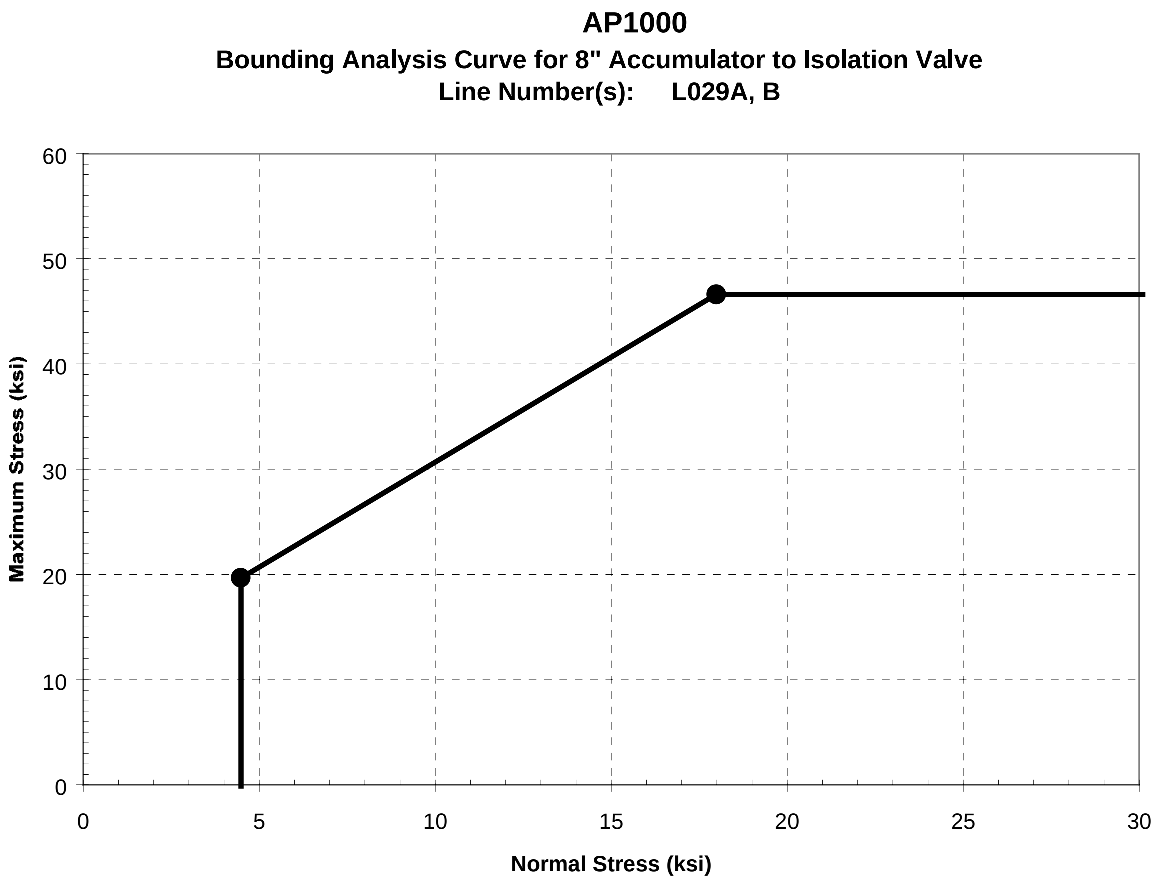


Figure 3B-12

Bounding Analysis Curve for 12″ PRHR Vent Line



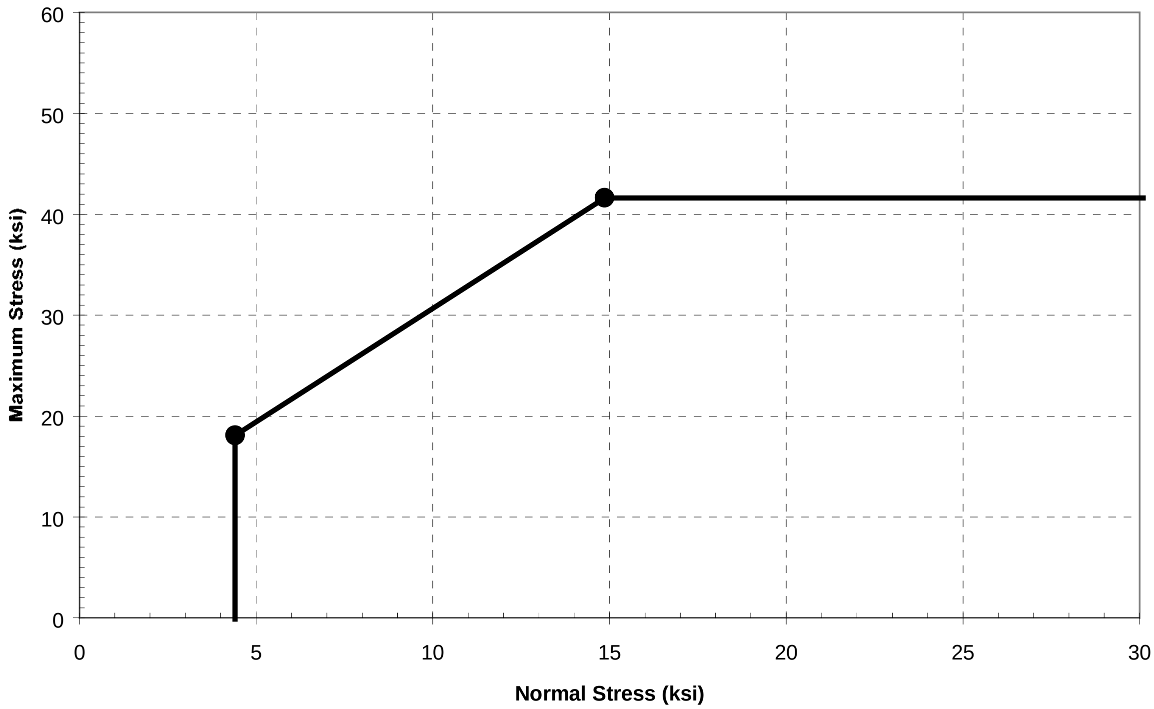
Pipe Designator:	EBC
System:	PXS
Nominal Diameter:	8 inch
Pipe Schedule:	40S
Outside Diameter:	8.625 inch
Pipe Material:	SA-312 TP304L
Minimum Weld Thickness:	0.302 inch

Normal Operating Pressure:	700.0 psig
Normal Operating Temperature:	120.0 F
Critical Flaw Size = 2 x Leakage Flaw Size	
Load Margin = 1.0	

Figure 3B-13

Bounding Analysis Curve for 8″ Accumulator to Isolation Valve

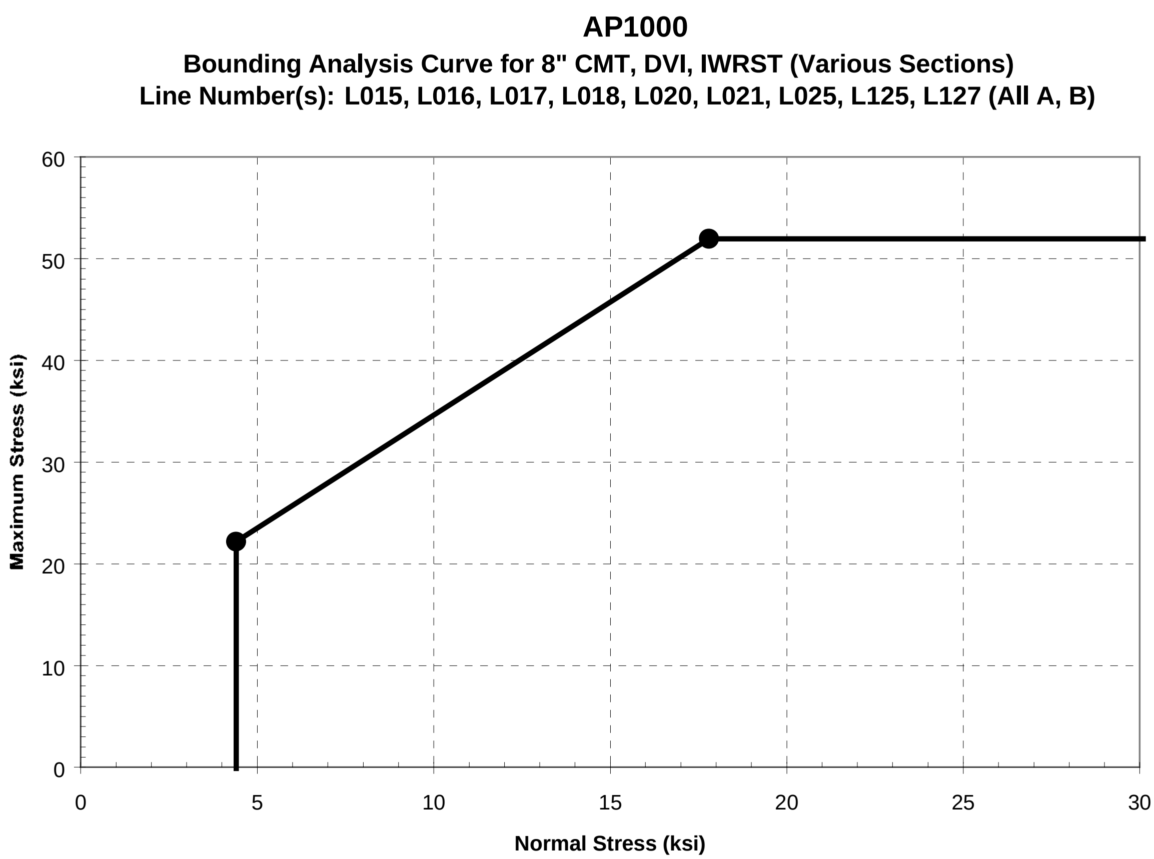
AP1000
Bounding Analysis Curve for 8" CMT Cold Leg Balance Line and Vent, DVI Cold Trap to RV
Line Number(s): L007A, B ; L021A, B ; L070A, B ; L118A, B



Pipe Designator:	BTA	Normal Operating Pressure:	2310.0 psig
System:	RCS, PXS	Normal Operating Temperature:	537.0 F
Nominal Diameter:	8 inch	Critical Flaw Size = 2 x Leakage Flaw Size	
Pipe Schedule:	160	Load Margin = 1.0	
Outside Diameter:	8.625 inch		
Pipe Material:	SA-312 TP316LN		
Minimum Weld Thickness:	0.817 inch		

Figure 3B-14

Bounding Analysis Curve for 8″ CMT Cold Leg Balance Line and Vent, DVI Cold Trap to RV



Pipe Designator:	BTA	Normal Operating Pressure:	2310.0 psig
System:	PXS	Normal Operating Temperature:	120.0 F
Nominal Diameter:	8 inch	Critical Flaw Size = 2 x Leakage Flaw Size	
Pipe Schedule:	160	Load Margin = 1.0	
Outside Diameter:	8.625 inch		
Pipe Material:	SA-312 TP316LN		
Minimum Weld Thickness:	0.817 inch		

Figure 3B-15

Bounding Analysis Curve for 8″ CMT, DVI IWRST (Various Sections)

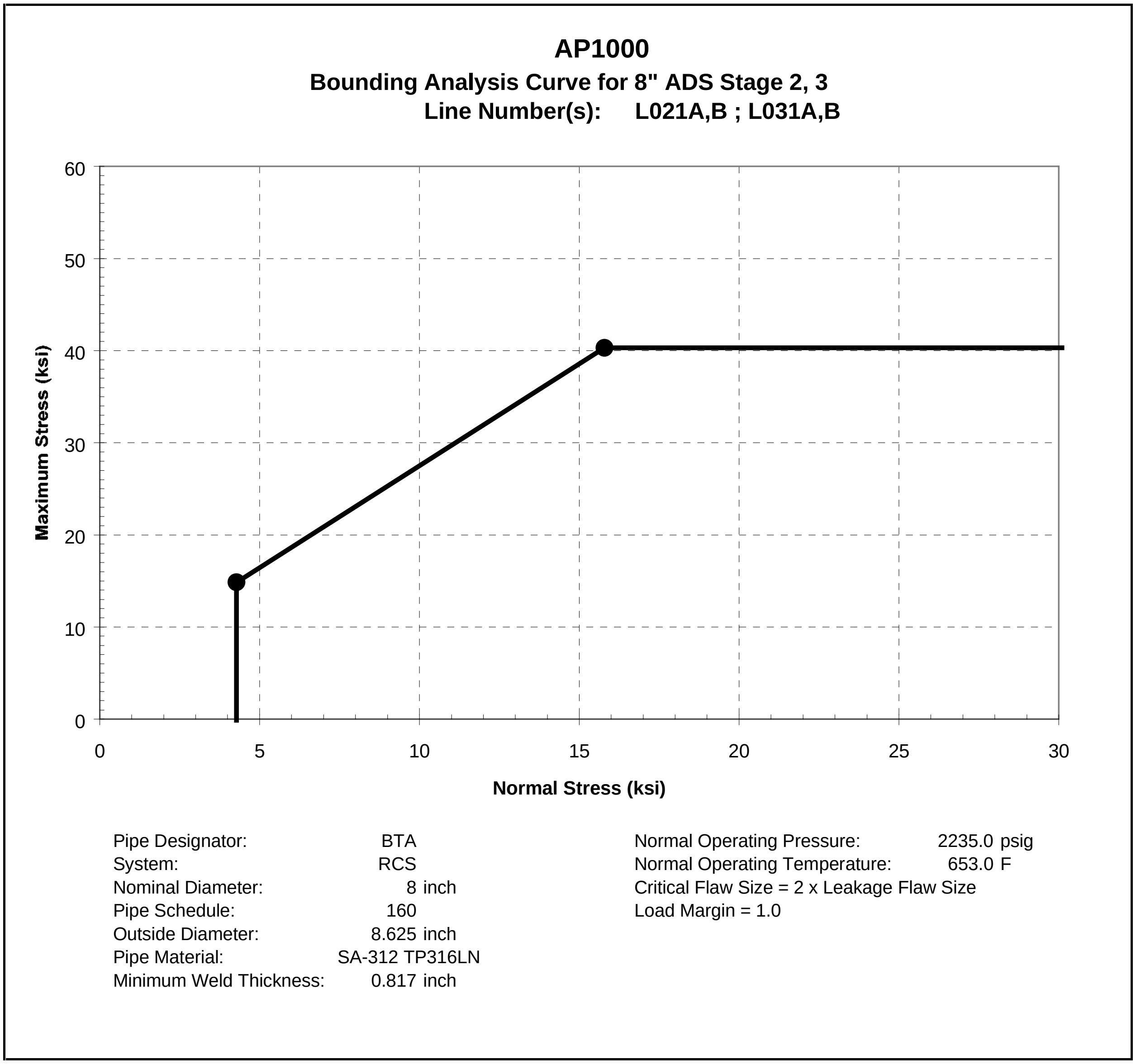
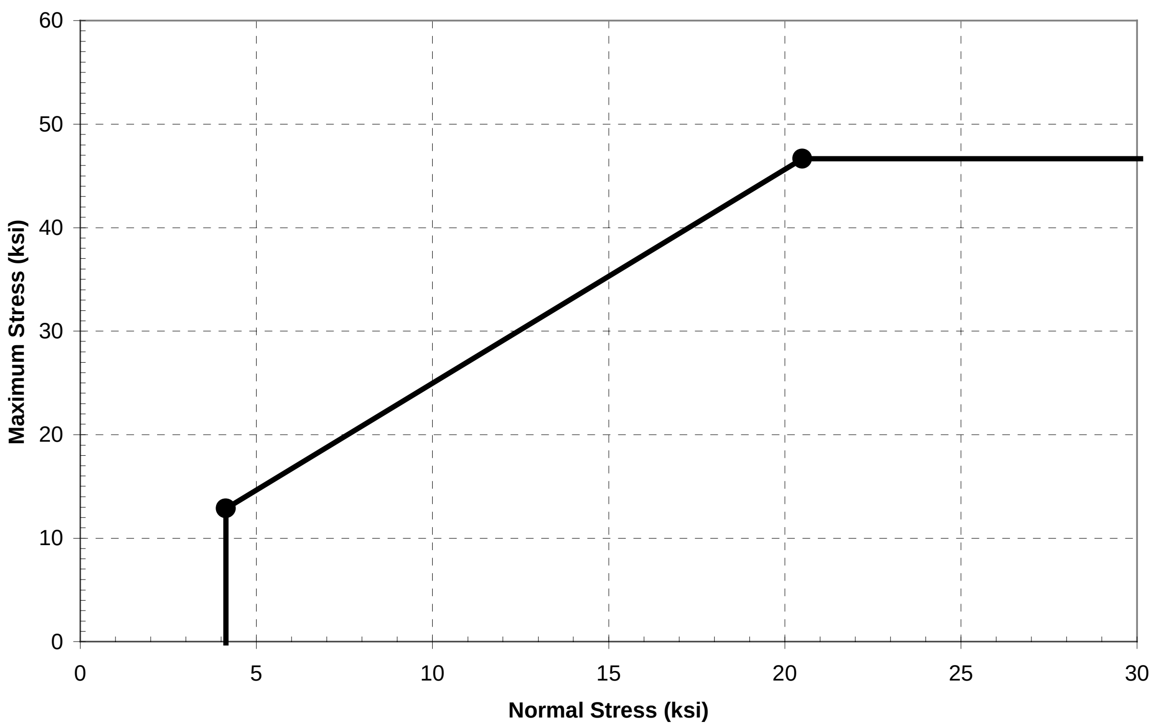


Figure 3B-16

Bounding Analysis Curve for 8″ ADS Stage 2, 3

AP1000
Bounding Analysis Curve for Accumulator after Isolation Valve
Line Number(s): L027A, B

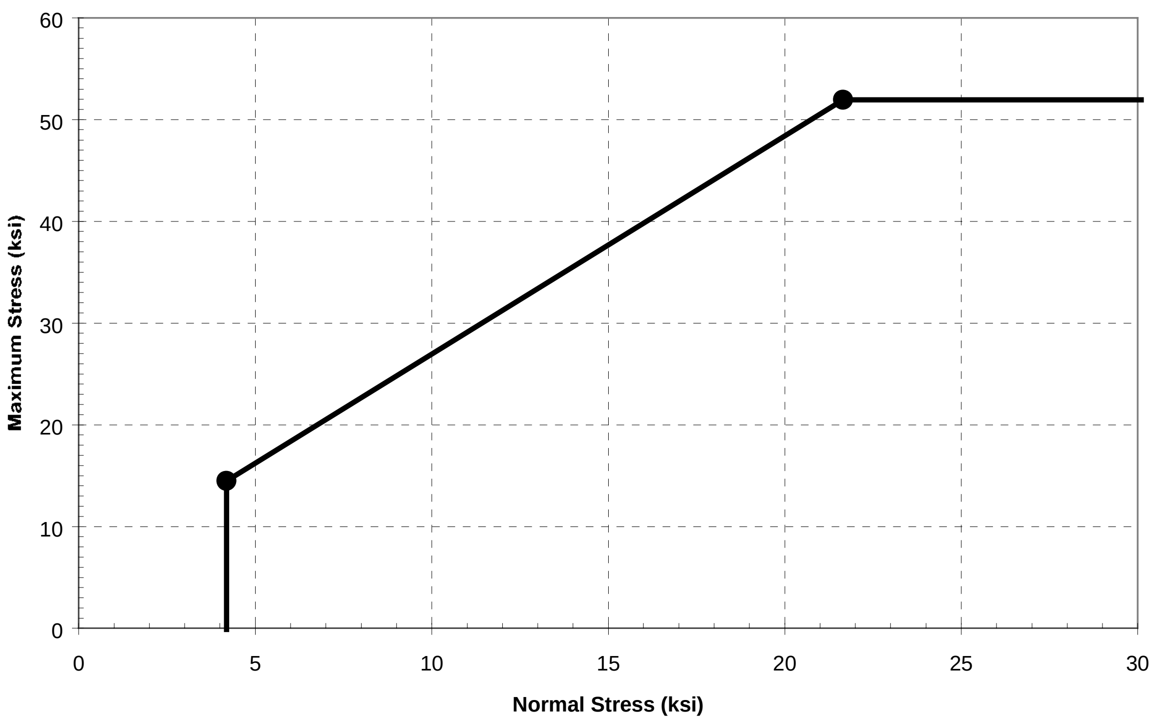


Pipe Designator:	BBC	Normal Operating Pressure:	700.0 psig
System:	PXS	Normal Operating Temperature:	120.0 F
Nominal Diameter:	8 inch	Critical Flaw Size = 2 x Leakage Flaw Size	
Pipe Schedule:	160	Load Margin = 1.0	
Outside Diameter:	8.625 inch		
Pipe Material:	SA-312 TP304L		
Minimum Weld Thickness:	0.817 inch		

Figure 3B-17

Bounding Analysis Curve for Accumulator after Isolation Valve

AP1000
Bounding Analysis Curve for RNS Discharge
Line Number(s): L019A, B



Pipe Designator:	BTA	Normal Operating Pressure:	2310.0 psig
System:	PXS	Normal Operating Temperature:	120.0 F
Nominal Diameter:	6 inch	Critical Flaw Size = 2 x Leakage Flaw Size	
Pipe Schedule:	160	Load Margin = 1.0	
Outside Diameter:	6.625 inch		
Pipe Material:	SA-312 TP316LN		
Minimum Weld Thickness:	0.651 inch		

Figure 3B-18

Bounding Analysis Curve for RNS Discharge

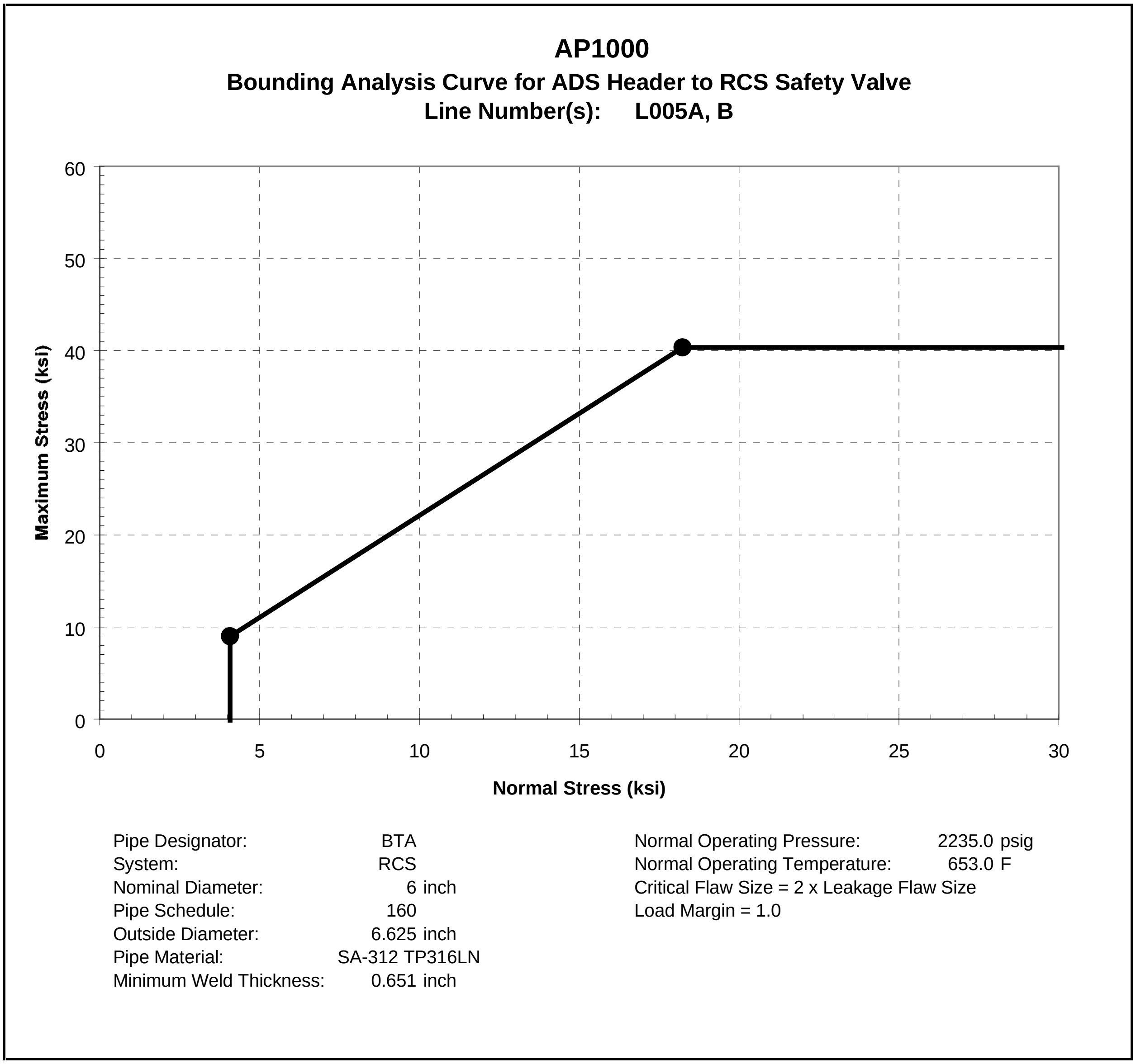
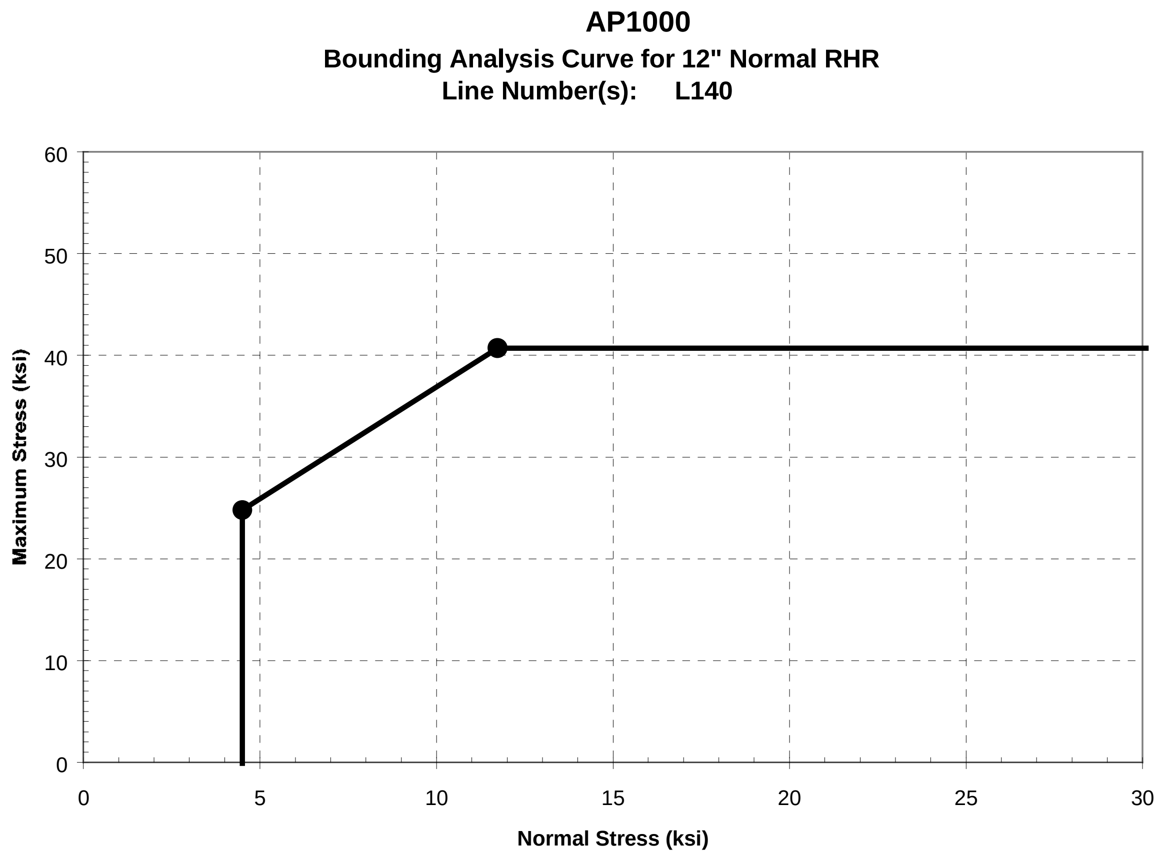


Figure 3B-19

Bounding Analysis Curve for ADS Header to RCS Safety Valve



Pipe Designator:	BTA	Normal Operating Pressure:	2248.0 psig
System:	RCS	Normal Operating Temperature:	610.0 F
Nominal Diameter:	12 inch	Critical Flaw Size = 2 x Leakage Flaw Size	
Pipe Schedule:	160	Load Margin = 1.0	
Outside Diameter:	12.750 inch		
Pipe Material:	SA-312 TP316LN		
Minimum Weld Thickness:	1.169 inch		

Figure 3B-20

Bounding Analysis Curve for 12″ Normal RHR

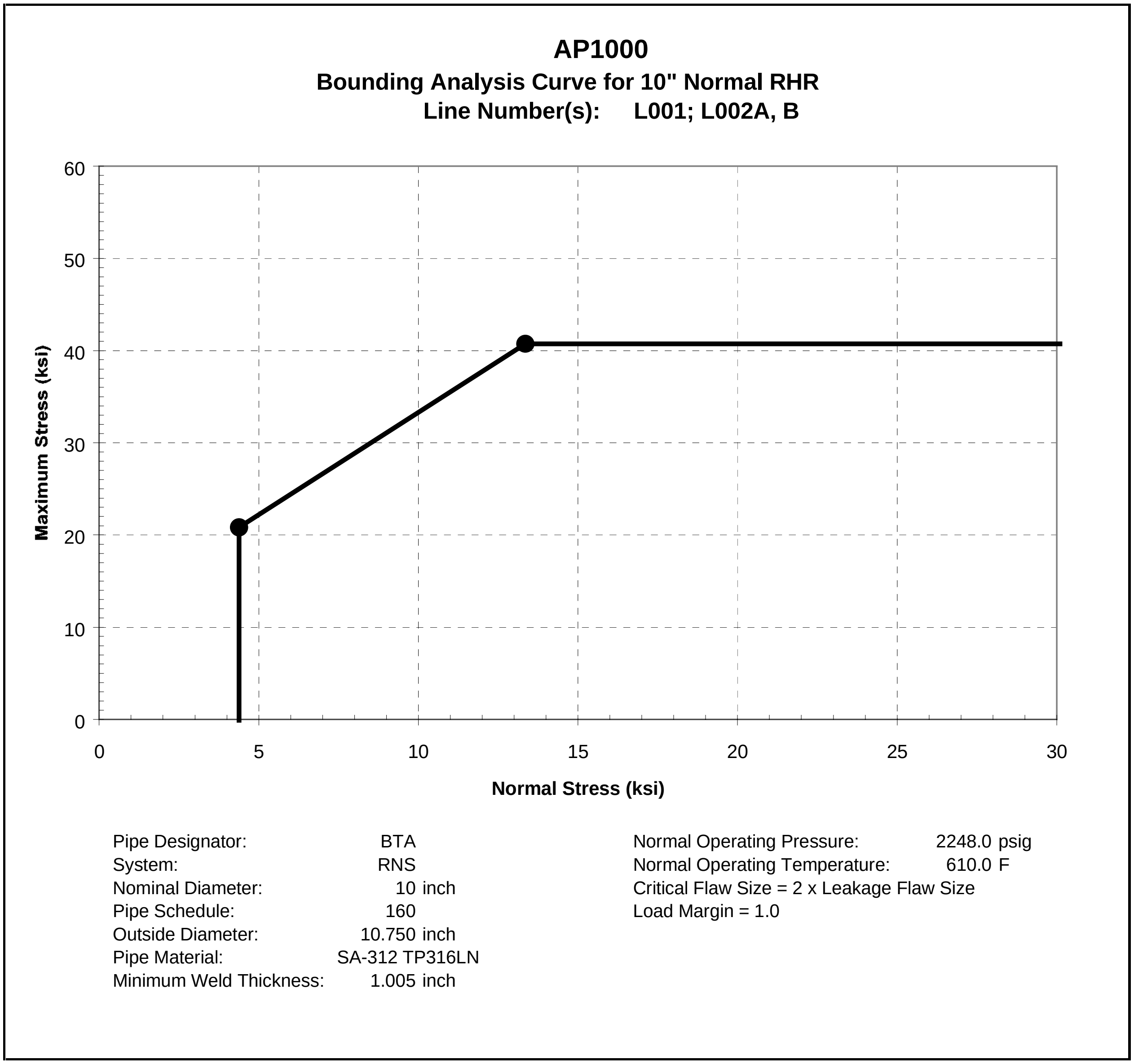


Figure 3B-21

Bounding Analysis Curve for 10″ Normal RHR

APPENDIX 3C

REACTOR COOLANT LOOP ANALYSIS METHODS

The AP1000 reactor coolant loop (RCL) model consists of three-dimensional finite elements such as pipes, beams, elbows, masses, and springs. The structural model is subjected to internal pressure, thermal expansion, weight and seismic loadings with imposed boundary conditions. The finite element displacement method is used for the analysis. The stiffness matrix for each element is assembled into a system of simultaneous linear equations for the entire structure. This set of equations is then solved by a variation of the Gaussian elimination method, known as the wave-front technique. This technique makes it possible to solve systems of equations with a large number of degrees of freedom using a minimum amount of computer memory.

3C.1 Reactor Coolant Loop Model Description

The piping model of the reactor coolant loop consists of a number of elements of given dimensions, sizes, and physical properties that mathematically simulate the structural response of the physical system. The system model contains the reactor pressure vessel (RPV), two steam generators (SGs), four reactor coolant pumps (RCPs), the containment interior building structure, the reactor coolant loop piping, the surgeline piping, and the primary equipment supports. A two-loop model is developed for the AP1000 reactor coolant loop system.

The containment interior building structure model is included in the seismic system model when the time-history integration method is used.

The stiffness and mass effects of branch piping connected to the primary loop piping are considered when significant (subsection 3.7.3.8.1).

3C.1.1 Steam Generator Model

3C.1.1.1 Steam Generator Mass and Geometrical Model

The steam generator is represented by discrete masses. The geometry of the steam generator vessel is used to determine the properties of the equivalent piping elements that join the steam generator masses. The modulus of elasticity and coefficient of thermal expansion corresponding to the thermal conditions are applied to the steam generator equivalent piping elements.

3C.1.1.2 Steam Generator Supports

The values of the steam generator support stiffnesses and locations of the supports are determined from the finite element models of the support members. The stiffness of the upper lateral supports include the steam generator shell flexibility. The local concrete building flexibility is included in the support stiffness.

3C.1.2 Reactor Coolant Pump Model

3C.1.2.1 Static Model

The reactor coolant pump is modeled using equivalent pipe elements. The modulus of elasticity and thermal expansion coefficient corresponding to each thermal condition are applied to these pipe elements.

3C.1.2.2 Seismic Model

The reactor coolant pump is represented by a multi-node model. The reactor coolant pump casing and motor are represented by reduced mass and stiffness matrices for horizontal and vertical motion. The reactor coolant pump rotor is represented by vertical mass and stiffness elements. The simplified reactor coolant pump model is obtained from a detailed model of the reactor coolant pump.

3C.1.2.3 Reactor Coolant Pump Supports

There are no reactor coolant pump supports. Two reactor coolant pumps are attached to the steam generator in each of the reactor coolant loops.

3C.1.3 Reactor Pressure Vessel Model

3C.1.3.1 Mass and Geometrical Model

The reactor pressure vessel model consists of equivalent pipe, stiffness, and mass elements. The elements represent the vessel shell, the vessel core barrel, the fuel assemblies, and the integrated head lift package.

The reactor pressure vessel is modeled with equivalent pipe elements and connecting bellows that place a given stiffness in series with a rigid piping element. The equivalent pipe element properties of the vessel and barrel are those of the cylindrical structures. The beam properties of the reactor internals are adjusted to simulate their fundamental frequency. The appropriate modulus of elasticity and coefficient of thermal expansion are used for the equivalent pipe elements representing the reactor pressure vessel.

3C.1.3.2 Reactor Pressure Vessel Supports

The reactor pressure vessel is supported at the four reactor pressure vessel inlet nozzles. Each support consists of a vertical stiffness and a lateral tangential stiffness. The support is represented by a stiffness matrix. The reactor pressure vessel supports are active for the analyzed loading conditions. The reactor pressure vessel model includes the effects of the vessel shell flexibility at the inlet and outlet nozzles. The local concrete building flexibility is included in the support stiffness.

3C.1.4 Containment Interior Building Structure Model

The containment interior building structure finite element model is made up of three-dimensional beam elements, spar elements, and pipe elements. This simplified building model is correlated to a detail model of the building.

3C.1.5 Reactor Coolant Loop Piping Model

The reactor coolant loop piping model consists of piping elements and bends. Each reactor coolant loop has two cold legs and one hot leg. The straight runs and bends of the cold leg and hot leg are input with the nominal dimensions. Each reactor coolant loop branch connection is represented by a node point. The reactor coolant loop piping model contains a distributed mass for static deadweight analysis and lumped masses for dynamic analysis.

3C.2 Design Requirements

The reactor coolant piping is qualified in according to the requirements of the ASME Code, Section III, Subsection NB, 1989 Edition with 1989 Addenda.

The containment interior concrete is represented by a nominal Young's modulus, including the effect of material uncertainty. The value of the modulus is changed to vary the building stiffness as described in subsection 3C.4.

The loadings for ASME Code, Section III, Class 1 components are defined in subsection 3.9.3. The following loadings are considered in the reactor coolant loop piping analysis:

- Design pressure (P)
- Weight (DW)
- Thermal expansion during normal operating condition
- Thermal expansion during other transient conditions (not part of this appendix)
- Safe shutdown earthquake (SSE)
- Design basis pipe break (DBPB)
- Building motions due to automatic depressurization system sparger discharge into the IRWST
- Thermal stratification during transient conditions

In addition to the analyses of these loads, the reactor coolant piping is analyzed for the effect of cyclic fatigue due to the design transients and earthquakes smaller than SSE.

3C.3 Static Analyses

3C.3.1 Deadweight Analysis

The reactor coolant loop piping system is analyzed for the effect of deadweight. The deadweight analysis is performed without considering the dry weight of the directly supported equipment. The effects of the auxiliary branch piping on the reactor coolant loop are generally negligible by the design of the auxiliary supports. A deadweight analysis is performed to include the total weight of the reactor coolant loop piping and the water weight in the components.

The reactor coolant loop deadweight model includes the corresponding active reactor coolant loop supports - reactor pressure vessel supports, and the steam generator column and lower lateral strut supports. The steam generator upper lateral snubber and bumper supports are considered as inactive. The containment interior building structure model is not considered in the deadweight analysis.

3C.3.2 Internal Pressure Analysis

The effects of the internal primary coolant pipe pressure are used in the calculations of forces and moments for both the reactor coolant loop piping and equipment supports.

3C.3.3 Thermal Expansion Analysis

The reactor coolant loop piping is analyzed for the effects of thermal expansion. The thermal expansion analysis model considers the expansion of the reactor coolant loop piping, reactor pressure vessel, steam generator, reactor coolant pump, and the equipment supports. The stiffness effects of the auxiliary piping on the reactor coolant loop expansion are generally negligible by the design of the auxiliary lines supports.

3C.4 Seismic Analyses

The reactor coolant loop piping is analyzed for the dynamic effects of a safe shutdown earthquake (SSE).

The model used in the static analysis is modified for the dynamic analysis by including the lumped mass characteristics of the piping and equipment. The effect of the equipment motion on the reactor coolant loop piping and support system is obtained by modeling the mass and stiffness characteristics of the equipment in the overall system model. The reactor coolant loop seismic analysis is performed at normal full-power operation. This operating condition is considered based on the lower probability of occurrence of the earthquake at reactor coolant loop temperatures below full power.

The time history integration method of analysis is used with a coupled model of the reactor coolant loops and the interior concrete building. The seismic input considers the soil profiles described in subsection 3.7.1. This input is obtained from the nuclear island seismic analysis. The duration of the input is between 12 to 20 seconds, depending on the duration needed to envelop the design response spectra. For each of the soil profiles, either the building stiffness is varied by + or - 30 percent, or the time scale is shifted by + or - 15 percent, to account for uncertainties.

Composite modal damping is used with the building components at 5 percent and the loop components at 4 percent of the critical damping. The equipment support nonlinearities at the steam generator upper lateral snubbers and the reactor pressure vessel vertical supports are included in the coupled model. The steam generator snubbers have different stiffnesses in tension and compression. The reactor pressure vessel vertical supports are acting downward only and are preloaded by deadweight, pressure, and thermal expansion loadings.

3C.5 Reactor Coolant Loop Piping Stresses

To prevent gross rupture of the reactor coolant loop piping system, the general and local primary membrane stress criteria must be satisfied. This is accomplished by satisfying Equation (9) in paragraph NB-3652 of the ASME Code, Section III. The secondary stress caused by thermal expansion is qualified by satisfying Equation (12) in paragraph NB-3653 of the ASME Code, Section III.

3C.6 Description of Computer Programs

This section provides a list of computer codes used for the AP1000 reactor coolant loop system analysis. Brief descriptions of the functions of each computer code are the following:

WECAN/WECAN-PLUS – Performs Structural Analysis Using Finite Element Analysis Method. WECAN is a mainframe program while WECAN-PLUS uses a workstation. Displacements and loads are calculated at the pipe elements, supports and equipment nozzles for pressure, deadweight, thermal, and seismic loadings.

STRESCAL – Post-processes the WECAN output data to calculate time history loads in selected elements. Input consists of a Modal Force File and a time history Modal Coefficient File for each mode. STRESCAL combines the results for the modes.

ANSYS – Performs Structural Analysis Using Finite Element Analysis Method. ANSYS is used in the loop model described in subsection 3.7.2. 3.1 and shown in Figure 3.7.2-7. This ANSYS model may be modified in accordance with this Appendix and ANSYS may be used in lieu of WECAN for the reactor coolant loop qualification analysis.

APPENDIX 3D

METHODOLOGY FOR QUALIFYING AP1000 SAFETY-RELATED ELECTRICAL AND MECHANICAL EQUIPMENT

Safety-related electrical equipment is tested under the environmental conditions expected to occur in the event of a design basis event. This testing provides a high degree of confidence in the safety-related system performance under the limiting environmental conditions. Qualification criteria were revised by IEEE 323-1974 (Reference 1) and by Regulatory Guide 1.89, which endorses this IEEE standard. The concept of aging was highlighted in IEEE 323-1974, and interpretation of the scope of aging and implementation methods were subsequently developed. 10 CFR 50.49 provides the NRC requirements for qualification of equipment located in potentially harsh environments. Therefore, the guidance provided by IEEE 323-1974 is the evolutionary root of requirements, recommended methods, and qualification procedures described in this appendix.

Specific treatment of seismic qualification, part of the qualification test sequence recommended in IEEE 323-1974, is addressed in IEEE 344-1987 (Reference 2). This appendix bases technical guidance, recommendations, and requirements for seismic qualification on IEEE 344-1987.

The AP1000 Equipment Qualification methodology addresses the expanded scope of IEEE 627-1980 (Reference 3), which encompasses the qualification of Class 1E electrical and safety-related mechanical equipment. IEEE 627 generalizes the principles and technical guidance of IEEE 323 and 344. Compliance with the IEEE 323-1974 and 344-1987 is the specific means of compliance with the intent of IEEE 627-1980 for safety-related electrical and mechanical equipment.

Safety-related electrical and mechanical equipment is typically qualified using analysis, testing, or a combination of these methods. The specific method or methods used depend on the safety-related function of the equipment type to be qualified. Safety-related mechanical equipment, such as tanks and valves, is typically qualified by analysis, with supplementary functional testing when functional operability is demonstrated only through testing, as is the case for active valves. Either testing or testing combined with analysis is the method used for environmental and seismic qualification of safety-related (Class 1E) electrical equipment.

The technical discussions of this appendix follow the format headings of the equipment qualification data packages (EQDPs) to be issued as specific qualification program documentation. This formatting (see Section 3D.7) permits easy cross-reference between the methodology defined in this report and the detailed plans contained in the equipment qualification data packages. Attachment A of this appendix is the format used for the equipment qualification data package.

Attachment B of this appendix, "Aging Evaluation Program," describes methods for addressing potential age-related, common-mode failure mechanisms used in AP1000 equipment qualification programs. The approach conforms with current industry positions and makes maximum use of available data and experience in the evaluation, test, and analysis of aging mechanisms.

Attachment C, "Effects of Gamma Radiation Doses Below 10^4 rads on the Mechanical Properties of Materials," provides the basis that radiation aging below 10^4 rads is not a significant factor in the ability of the equipment to perform properly during a seismic event. For some devices, electrical properties are degraded below 10^3 rads. Radiation aging for equipment not required to perform a safety-related function in a high-energy line break environment and subject to lifetime doses of less than 10^4 rads is not addressed in AP1000 test programs.

Attachment D, "Accelerated Thermal Aging Parameters," describes the methodology employed in calculating the accelerated thermal aging parameters used in this program.

Attachment E, "Seismic Qualification Techniques," discusses available methods for establishing a seismic qualification basis, by either test or analysis, and its application to the qualification of safety-related equipment for the AP1000.

3D.1 Purpose

The basic objectives of qualification of safety-related electrical and mechanical equipment follow:

- To reduce the potential for common cause failures due to specified environmental and seismic events
- To demonstrate that safety-related electrical and mechanical equipment is capable of performing its designated safety-related functions.

This appendix describes the methodology that has been adopted to qualify equipment according to IEEE 627-1980, "IEEE Standard for Design Qualification of Safety System Equipment Used in Nuclear Power Generating Stations." The two standards primarily used to demonstrate compliance with this standard are IEEE 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations," and IEEE 344-1987, "IEEE Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations."

3D.2 Scope

The qualification criteria, methods, and environmental conditions described herein constitute the methodology that has been adopted to comply with the forenamed standards for the AP1000. This methodology applies to safety-related, seismic Category I electrical and mechanical equipment and is also utilized for certain monitoring equipment. Seismic Category II equipment is not within the scope of this program.

Performance during abnormal environmental conditions, while not specifically designated as an industry or a regulatory qualification requirement, is also addressed by this appendix. Performance during normal service conditions is demonstrated by tests and inspections addressed by the equipment specification. Electromagnetic interference (EMI) testing or analysis is not included in the qualification process and is addressed on an individual equipment basis, as necessary.

3D.3 Introduction

This appendix identifies qualification methods used for the AP1000 to demonstrate the performance of safety-related electrical and mechanical equipment when subjected to abnormal and accident environmental conditions including loss of ventilation systems, feedline, steamline and main coolant system breaks, and seismic events. This appendix provides the expected conditions for various locations in the AP1000. General requirements for the development of plans/procedures/reports are also provided. Section 3D.4 identifies the various industry and regulatory criteria upon which the program is based. Section 3D.5 defines the design specifications and applicable test environments. Section 3D.6 defines the basis for the qualification method selection. Section 3D.7 outlines the documentation requirements.

3D.4 Qualification Criteria

The environmental requirements considered in the design of safety-related equipment are embodied in GDC 2, "Design Bases for Protection Against Natural Phenomena"; GDC 4, "Environmental and Missile Design Bases"; and GDC 23, "Protection System Failure Modes." GDC 1, "Quality Standards and Records," and Criterion III, "Design Control," Criterion XI, "Test Control," and Criterion XVII, "Quality Assurance Record" of 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to require that the environmental design of safety-related equipment is verified, documented, and controlled.

The qualification methods described in this appendix are used to verify the environmental design basis and capability of the safety-related electrical and mechanical equipment supplied for the AP1000. The results of the verification, as well as the design basis for each equipment, is documented in an equipment qualification data package. (See Attachment A for sample format.) Design control, test control, and quality assurance record keeping is performed through the AP1000 Quality Assurance Program. (See Chapter 17.)

3D.4.1 Qualification Guides

IEEE 323-1974 and 344-1987 serve as the basis upon which the AP1000 equipment qualification methodology demonstrates compliance with IEEE 627-1980. NRC regulations stated in 10 CFR 50.49, "Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants," and NRC guidance provided in Regulatory Guide 1.89, and Regulatory Guide 1.100, endorse IEEE 323-1974 and IEEE 344-1987, respectively. The intent of the more general IEEE 627-1980 is addressed through conformance with IEEE 323 and 344.

3D.4.1.1 IEEE Standards

The following lists additional standards and guides used in developing the methodology:

- IEEE 98-1984, "IEEE Standard for the Preparation of Test Procedures for the Thermal Evaluation of Solid Electrical Insulating Materials"

- IEEE 100-1996, "IEEE Standard Dictionary of Electrical and Electronic Terms"

- IEEE 308-1991, "IEEE Standard Criteria for Class 1E Power System for Nuclear Power Generating Stations"
- IEEE 317-1983, "IEEE Standard for Electric Penetration Assemblies in Containment Structure for Nuclear Power Generating Stations"
- IEEE 381-1977, "IEEE Standard Criteria for Type Tests of Class 1E Modules Used in Nuclear Power Generating Stations"
- IEEE 382-1996, "IEEE Standard for Qualification of Actuators for Power-Operated Valve Assemblies with Safety-Related Functions for Nuclear Power Generating Stations"
- IEEE 383-1974, "IEEE Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations"
- IEEE 420-1982, "IEEE Standard Design and Qualification of Class 1E Control Boards, Panels, and Racks Used in Nuclear Powered Generating Stations"
- IEEE 494-1974, "IEEE Standard Method for Identification of Documents Related to Class 1E Equipment and Systems for Nuclear Power Generating Stations"
- IEEE 535-1986, "IEEE Standard for Qualifying Class 1E Lead Storage Batteries for Nuclear Power Generating Stations"
- IEEE 572-1985, "IEEE Standard for Qualification of Class 1E Connection Assemblies for Nuclear Power Generating Stations"
- IEEE 603-1991, "IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations"
- IEEE 649-1991, "IEEE Standard for Qualifying Class 1E Motor Control Centers for Nuclear Power Generating Stations"
- IEEE 650-1990, "IEEE Standard for Qualification of Class 1E Static Battery Chargers and Inverters for Nuclear Power Generating Stations"
- IEEE-741-1997, "IEEE Standard Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations"
- ANSI/IEEE C37.98-1987, "IEEE Standard for Seismic Testing of Relays".

3D.4.1.2 NRC Regulatory Guides

In the area of seismic and environmental qualification of safety-related electrical and mechanical equipment, the NRC has issued the following Regulatory Guides:

Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)" – The guide endorses ANS and ANSI standards for quality assurance programs, but is considered here specifically for guidance in determining documentation adequacy. Appendix A of the guide, Item 9, "Procedures for Performing Maintenance," addresses procedural and documentation requirements for maintenance of safety-related equipment, preventive maintenance, repair, and replacement. This guide is a source in the development of qualification efforts that rely on operating experience, as described in subsection 3D.6.3, or in the on-going qualification programs discussed in subsection 3D.6.4.

Regulatory Guide 1.61, "Damping Values for Seismic Design of Nuclear Plants" – The guide prescribes acceptable values of damping used in elastic modal dynamic seismic analysis of seismic Category I structures, systems, and components. The AP1000 equipment qualification program is based on Regulatory Guide 1.61 and on values considered to be acceptable based on past NRC acceptances. The safe shutdown earthquake (SSE) damping values used for the qualification of mechanical and electrical equipment are listed in Table 3.7.1-1 of Chapter 3.

Regulatory Guide 1.63, "Electric Penetration Assemblies in Containment Structures for Nuclear Power Plants" – The guide endorses, with certain qualifications, IEEE 317-1983. External circuit protection of electric penetration assemblies should meet the provisions of Section 5.4 of IEEE 741-1986, "Criteria for Protection of Class 1E Power Systems and Equipment in Nuclear Generating Stations, as these are beyond the of scope IEEE 317. The AP1000 design complies with IEEE 741-1997. The AP1000 equipment qualification program employs the recommendations of Regulatory Guide 1.63, Revision 3, in specifying qualification plans as a means of supplementing the guidance of IEEE 317 and 323.

Regulatory Guide 1.73, "Qualification Tests of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants" – The guide endorses, with certain qualifications, IEEE 382-1972. The AP1000 equipment qualification program employs recommendations of Regulatory Guide 1.73, but gives preference to the guidance of IEEE 382-1985, where it is necessary to supplement the guidance of IEEE 323 or 344 in specifying qualification plans for electric valve operators.

Regulatory Guide 1.89, "Qualification of Class 1E Equipment for Nuclear Power Plants" – The guide provides guidance for conformance with 10 CFR 50.49, and endorses the procedures of IEEE 323-1974 as an acceptable means for qualifying Class 1E equipment. Implicit in the endorsement of IEEE 323 is the reference to seismic qualification methods of IEEE 344 as a part of the qualification test sequence. (See Regulatory Guide 1.100 later in this discussion.) The AP1000 equipment qualification methodology addresses the recommendations of Regulatory Guide 1.89 by the following:

- The recommendations of IEEE 323-1974 are met by the methods discussed in this appendix

- The radiation source terms used in qualification differ from those of Regulatory Guide 1.89, and are described in Section 3D.5 of this appendix

- The seismic qualification requirements employ the recommendations of IEEE 344-1987 as described in Attachment E of this appendix.

Regulatory Guide 1.92, "Combining Modal Responses and Spatial Components in Seismic Response Analysis" – The guide describes methods and procedures for the following:

- Combining the values of the response of individual modes in a response spectrum modal dynamic analysis to find the representative maximum value of a particular response of interest for each of the three orthogonal seismic spatial components

- Combining the maximum values (or representative maximum values) of the responses for a given element of a system or item of equipment, determined for each of the three orthogonal spatial components.

The AP1000 equipment qualification program employs methods consistent with the recommendations of Regulatory Guide 1.92 when combining individual modal response values or the response of three independent spatial components in seismic analyses.

Regulatory Guide 1.100, "Seismic Qualification of Electrical Equipment for Nuclear Power Plants" – The guide endorses IEEE 344-1987. Regulatory Guide 1.100 particularly notes that IEEE 344-1987 is applied in the qualification of safety-related mechanical equipment, as well as Class 1E electrical equipment. The AP1000 equipment qualification methodology employs the recommendations of Regulatory Guide 1.100, as described in Attachment E of this appendix.

Regulatory Guide 1.122, "Development of Floor Design Response Spectra for Seismic Design of Floor-Supported Equipment or Components" – The guide describes specific methods for developing floor (and other equipment mounting locations) response spectra. Included are specific criteria for the broadening frequency amplitude peaks and smoothing of the frequency amplitude spectrum to incorporate conservatism in the seismic requirements. This is to compensate for other uncertainties of analysis. The AP1000 equipment qualification program employs methods consistent with the recommendations of Regulatory Guide 1.122.

Regulatory Guide 1.131, "Qualification Tests of Electrical Cables, Field Splices, and Connections for Light-Water Cooled Nuclear Power Plants" – The guide endorses IEEE 383-1974. The AP1000 equipment qualification program employs the recommendations of Regulatory Guide 1.131 in specifying the qualification program plans where this guide supplements the guidance of IEEE 383 and to further demonstrate conformance with the guidance of IEEE 323. As neither IEEE 383 nor Regulatory Guide 1.131 specifically addresses considerations for cable field splices and connections, guidance for their qualification is taken from IEEE 572 and Regulatory Guide 1.156.

Regulatory Guide 1.156, "Environmental Qualification of Connection Assemblies for Nuclear Power Plants" – The guide endorses IEEE 572-1985. The AP1000 equipment qualification program employs the recommendations of Regulatory Guide 1.156 in specifying the qualification program plans where this guide supplements the guidance of IEEE 572 to demonstrate conformance with the guidance of IEEE 323.

Regulatory Guide 1.158, "Qualification of Safety-Related Lead Storage Batteries for Nuclear Power Plants" – The guide endorses IEEE 535-1986. The AP1000 equipment qualification program employs the recommendations of Regulatory Guide 1.158 in specifying the qualification program plans where this guide supplements the guidance of IEEE 535 to demonstrate conformance with the guidance of IEEE 323.

3D.4.2 Definitions

Definitions of terms used in this appendix are contained in the referenced standards and IEEE 100, "IEEE Dictionary of Electrical and Electronic Terms." Subsection 3D.4.5 clarifies the definitions of "life" (that is, design, shelf, and qualified life) as used in this methodology. The terms "design life" and "qualified life" have the meanings set forth in IEEE 323 and are used in the context of that standard.

3D.4.3 Mild Versus Harsh Environments

Qualification requirements differ for equipment located in mild and harsh environments.

IEEE 323 defines a mild environment as an environment expected as a result of normal service conditions and the extremes of abnormal service conditions where a safe shutdown earthquake is the only design basis event of consequence or conditions where thresholds of material degradation are reached. The following limits are established as the delimiting environmental parameter values for mild and harsh environments.

Typically a mild environment conforms with the environmental parameter limits of Table 3D.4-1, though others may apply to specific equipment applications or locations.

The scope of 10 CFR 50.49 is limited exclusively to equipment located in a harsh environment. The AP1000 equipment qualification program conforms with the requirements of 10 CFR 50.49 for the qualification of harsh environment equipment. The "radiation-harsh" environment is a significant subset of the harsh environment category. A radiation-harsh environment is defined for equipment designed to operate above certain radiation thresholds where other environmental parameters remain bounded by normal or abnormal conditions. Any equipment that is above 10^4 rads gamma (10^3 for electronics) will be evaluated to determine if a sequential test which includes aging, radiation, and the applicable seismic event is required or if sufficient documentation exists to preclude such a test.

3D.4.4 Test Sequence

Where the test sequence deviates from that recommended by IEEE 323-1974, the deviation is justified. The test sequence employed for a given hardware item is specified in the equipment qualification data package Sections 2.1 and 3.6 (see Attachment A for example). Note that for this

reference and subsequence references to Attachment A the information in Attachment A will be completed by the Combined License applicant. Clarifications to the IEEE 323-1974 recommended test sequence are discussed in the following:

1. Burn-In Test

   For electronic equipment, a burn-in test is completed, before operational testing of the equipment, to eliminate infant failures. The test consists of energizing the equipment for a minimum of 50 hours at nominal voltage and frequency under ambient temperature conditions. Any malfunction observed during these tests are repaired, and the 50-hour burn-in test is repeated for the repaired portion of the equipment.

2. Performance Extremes Test

   For equipment where seismic testing has previously been completed employing the recommended methods of IEEE 344-1987, seismic testing is not repeated. Testing of the equipment to demonstrate qualification at performance extremes is separately performed as permitted by IEEE 323-1974, subsection 6.3.2(3). Additional discussion is provided in subsection 3D.6.5.1.

3. Aging Simulation and Testing

   For equipment located in a mild environment, aging is addressed as described in subsections 3D.6.3, 3D.6.4, and Attachment B. If there are no known aging mechanisms that significantly degrades the equipment during its service life, it is acceptable to perform seismic testing of unaged equipment. Separate testing or analysis (or both) is provided to demonstrate that the aging of components is not significant during the projected service or qualified life of the equipment.

4. Synergistic Effects

   An important consideration in the aging of equipment for harsh environment service is the possible existence of synergistic effects when multiple stress environments are applied simultaneously. This potential is addressed by conservatism inherent in the determination and use of the worst-case aging sequence and conservative accelerated aging parameters.

   The combination of effects from pressure, temperatures, humidity, and chemistry are addressed by the high-energy line break (HELB) tests. Since the test item is not exposed to radiation during this test, the effects of this parameter are conservatively addressed by subjecting the test items to the required total integrated dose before the high-energy line break. Specifically for instruments, the summing of errors for the irradiation and high-energy line break portions of the test sequence is a means of achieving conservatism.

5. Visual Inspections/Disassembly

   The results of post-test visual inspections are not necessarily documented unless problems are discovered. Disassembly is performed only when test results or visual inspections require further investigation.

3D.4.5 Aging

3D.4.5.1 Design Life

The AP1000 equipment qualification program relies on the IEEE 323 definition for design life, particularly its distinction with respect to qualified life.

Instead of determining a qualified life for mild environment equipment for which the seismic event is the exclusive design basis event to be addressed, a design life is determined. Design lives offered in manufacturers' literature are accepted cautiously, particularly where the equipment is typically used for applications outside the nuclear industry.

An application of the design life is substantiated by sound bases in reliability theory and relevant industry standards, or experience data sources within the nuclear industry. Analyses treats the applicability and similarity of the equipment and conditions relevant for the AP1000 safety-related application. These analyses, and documentation of such, conform with guidelines of IEEE standards, as applicable, and with Sections 3D.6 and 3D.7 of this appendix.

3D.4.5.2 Shelf Life

Based on recommended storage environments, the shelf life of an equipment item is not typically a significant portion of the defined qualified life. For example, ambient temperatures during storage are typically less than the operating temperatures assumed for aging calculations. Therefore, as long as equipment is in storage and is not energized (not experiencing self-heating), a reduction in qualified life is not appropriate. However, if storage conditions differ significantly from those recommended or the storage time becomes dramatically extended, the impact to the qualified life is determined by application of the Arrhenius time-temperature relationship.

3D.4.5.3 Qualified Life

A qualified life is established for each item of safety-related equipment that is exposed to a harsh environment based on the conditions postulated at the equipment location with consideration of the equipment operability requirements.

The determination of qualified life considers potential aging mechanisms resulting from significant in-service thermal, radiation, and vibration sources, and the effects of operational cycling (mechanical or electrical or both). Generally, all aging mechanisms do not apply to each item of equipment. Relevant aging mechanisms addressed or simulated are determined jointly with the identification of the equipment's critical components, functional modes, and material characteristics, and the assessment of tolerable limits in degradation of the components. An a priori consideration in selecting equipment to qualify is the evaluation of the equipment's inherent capability to survive and operate under the conditions for which it is qualified.

Since past qualification tests have provided a substantial basis for this assessment (indeed, some may provide sufficient basis to preclude any new testing as part of the AP1000 program) specific guidance on each equipment type is not provided here. Application of the lessons of past tests, insights provided in generic industry communications (for example, technical bulletins, NRC Information Notices), and sound judgment in the development of test plans and analysis

procedures are addressed in the documentation of qualification for each equipment type, as applicable.

Qualified life is established by the most limiting of the five aging mechanisms. Qualified life may be limited by the tolerable degradation of a single component or material critical to the equipment's capability to perform its safety function. Aging is subject to the requirement for margin. See subsection 3D.4.8 of this appendix.

For some equipment, qualified life is established on the basis of periodic replacement of certain short-lived, age-sensitive components. The user complies with the mandatory replacement practices documented in the equipment qualification data packages (see subsection 3D.7.2.5 and Attachment A, Sections 3.9.3 and 6.1) to affirm the equipment qualified life.

The objective of thermal and irradiation qualified life testing is to simulate, according to the available empirical material data, the degradation effects such that the equipment is in its end-of-life condition before the application of the design basis event conditions testing.

Thermal qualified life is evaluated using the Arrhenius time-temperature relationship. (See more detailed discussions in Attachments B and D of this appendix.) The activation energy is the exclusive material-dependent parameter input into the Arrhenius time-temperature relationship. The activation energy is an empirically determined parameter indicative of the thermal degradation of a physical property of a material (for example, elasticity of silicone rubbers or insulation resistance of cross-linked polyethylene cable insulation). Each material may have more than one physical property that may be subject to thermal degradation over time. Consequently, it may have different activation energies with respect to each property. Thus, the selection of activation energy considers the material property most germane to the safety-related function of the material or component. (Also see subsection 3D.4.5.4.)

Common practice for the evaluation of irradiation-induced degradation is to consider the sum of estimated life and the accident radiation doses before design basis event testing. When testing, the total dose is applied during the radiation aging simulation portion of the qualification test sequences. This is considered conservative because the equipment has accumulated an exposure, or total integrated dose, before the initiation of the seismic and accident environment testing. Further bases for test dose determination are provided in subsection 3D.5.1.2. Sufficient margin must be included in test parameters (see subsection 3D.4.8). The same margins are applied in an analysis of radiation life or design basis event radiation dosage.

The simulation of age also includes the effects of operational cycling, both electrical and mechanical. Generally, these considerations are applied specifically to electromechanical equipment such as valve operators, limit switches, motors, relays, switches, and circuit breakers. Furthermore, the simulation of these effects is waived where existing data demonstrates equipment durability greatly in excess of estimated number of operating cycles for Class 1E service. Analysis or justification is provided for any case where operational cycling is omitted in the test sequence.

It is not practicable to simultaneously simulate the aspects of aging. Development of each test plan considers known synergies and sequences the simulation of the various applicable aging mechanisms with regard for conservatism of the overall effect on the test specimens.

3D.4.5.4 Qualified Life Reevaluation

It may be possible to extend the qualified life of a particular piece of equipment at some future date by comparing the actual in-plant environments and conditions during the equipment's installed life to the values assumed for the AP1000 in establishing the qualified life. For example, the thermal qualified life might be extended by performing an analysis of actual internal or external temperatures (or both) experienced. Continuous temperature monitoring or use of sample devices for testing and trending materials aging may be used. These efforts reveal the conservatism of the original thermal life calculation, which assumes that the maximum value specified for the normal plant operating environment endured at all times.

Although a strict Arrhenius calculation may yield an extended qualified life, care is taken in using this extrapolation because of uncertainties in the methodology. The Arrhenius time-temperature relationship relies on empirically determined activation energies of materials. This parameter has been determined for a number of materials to at least a good approximation for small temperature extrapolations. Extrapolation of the Arrhenius model to time periods of temperature beyond the range of materials test data is questionable and may result in large errors.

Calculated qualified lives based on this methodology should be limited to 20 years unless sound technical bases can be cited. This position is consistent with industry guidelines such as IEEE 98-1984, NUREG/CR-3156 (Reference 4), and EPRI NP-1558 (Reference 5).

3D.4.6 Operability Time

The post-accident operability times specified in Section 1.7.1 of each equipment qualification data package (see Attachment A) are conservatively established based on the safety-related function performed by that equipment for the spectrum of design basis event conditions. These include the following:

- Trip and/or monitoring functions of sensors and instruments
- Operability requirements for electromechanical equipment
- Duration of required operability for active valves.

This evaluation also considers what consequences the failure of the device has on the operator's action or decisions and the mitigation of the event. Table 3D.4-2 lists and explains typical operability times.

For monitoring functions, simulated aging techniques are employed to shorten the test time following a high-energy line break. These also comply with the margin guidelines of subsection 3D.4.8.

Margins for trip function requirements are contained in the high-energy line break envelopes that encompass a full spectrum of break sizes. The defined margins are also justified by the fact that

the signal generated by the sensor is locked in by the protection system and does not reset should the sensor fail after completion of its designated trip time requirement.

3D.4.7 Performance Criterion

The basic performance criterion is that the qualification test program demonstrate the capability of the equipment to meet the safety-related performance requirements defined in the equipment qualification data package, Section 1.7, while subjected to the environmental conditions specified in the equipment qualification data package, Section 1.8. Where three or more specimens are tested, failure of one of three may be considered a random failure, subject to an investigation concluding that the observed failure is not indicative of a common-mode occurrence.

For equipment for which aging is addressed by evaluation of appropriate mechanism(s) through a review of available material and component information, the basic acceptance criterion is that the evaluation of test data demonstrate that the effect of aging is minor and does not affect the capability of the aged equipment to perform specified functions.

3D.4.8 Margin

IEEE 323 (Section 6.3.1.5) recommends that margin be applied to the most severe specified service conditions in order to establish the conditions for qualification. This margin is provided in order to account for normal variations in commercial production of equipment and for reasonable errors in defining satisfactory performance. Further guidance for determining the acceptability of margin with respect to application-specific or location-specific requirements is provided by the NRC in NUREG-0588 and Regulatory Guide 1.89, Revision 1. Margins are included in addition to conservatisms applied during the derivation of the local environmental conditions of the equipment, unless the conservatism is quantified and specifically shown to meet or exceed the guidance of IEEE 323, NUREG-0588, and Regulatory Guide 1.97.

Consistent with IEEE 323, margin is incorporated into the specification of the generic qualification parameters by either increasing the test levels, number of test cycles, test duration, or a combination of these options as appropriate. The AP1000 generic qualification parameters are selected to envelop a range of loss of coolant accident and high-energy line break sizes, and equipment locations. Margin in seismic conditions for test and analysis are addressed in subsection 3D4.8.4. The margins available for a specific application may be larger than the generic equipment qualification test objective for seismic events and some events outside containment and are verified on an application-specific basis.

In defining qualification parameters, the AP1000 equipment qualification program incorporates margin as described in the following subsections. Table 3D.4-3 lists margin requirements applied.

For generic testing, margin is applied at the time of testing to cover known safety-related applications of the equipment. Generally, this results in a worst-case test that provides substantial margin for applications where lesser environments apply. Application of margin for seismic qualification addresses several cases unique to the qualification approach. (See subsection 3D.4.8.4.)

3D.4.8.1 Normal and Abnormal Extremes

As indicated in Section 7 of IEEE 323, the application of margin is directed at specifying adequate qualification requirements for the most severe service conditions represented by the design basis events (that is, high-energy line break accidents and seismic events). Consequently, the AP1000 equipment qualification methodology does not apply any systematic margin to the normal and abnormal environment parameters in defining the qualification conditions.

For electronic equipment not required to operate in a high-energy line break environment, additional margin is included by requiring that the equipment operate through the conservative normal and abnormal service conditions indicated in Figure 3D.5-1. The environmental parameters at least equal the specified range of service condition parameters. An exception occurs for transmitters where a performance verification is completed at 130°F on each transmitter to encompass the specified maximum abnormal conditions. For equipment to be qualified to operate in a high-energy line break environment, qualification to the severe high-energy line break conditions demonstrates ample margin for acceptable performance under certain specified normal and abnormal service conditions.

3D.4.8.2 Aging

No specific margin is applied to the time component in deriving appropriate aging parameters, if margin is included in deriving the accelerated aging parameters employed for simulating each applicable aging mechanism.

Margin may be addressed by demonstrating the adequacy of the aging simulated by test through the calculation of time-temperature equivalence (See Attachment B of this appendix) or the comparison of simulated parameters with those applicable to the intended service of the equipment. The installed life of equipment must not exceed the thermal qualified life demonstrated by this calculation. Additionally, the selection and use of the thermal aging parameters both for test and subsequent calculations are subject to criteria, including the following:

- Test temperature must endure for at least 100 hours
- Test temperature must exceed any application temperature (that is, the normal or abnormal environment in which the equipment is to be used, and for which the life is calculated)
- Test temperature must be less than state-change temperature for materials critical to the equipment safety-related function or capability to endure the subsequent design basis event testing
- A conservative activation energy is used. Activation energies for materials critical to the equipment safety-related function or capability to endure the subsequent design basis event testing are considered. Materials may have several activation energies, each for a different material property. Relevant material properties are considered.

If margin is not demonstrated through conservatism in the aging parameters or calculation, then a +10 percent time margin is included.

A margin of 10 percent in the other parameters (for example, irradiation, operational cycling) applies to both the aging simulation and the post-accident simulated aging, with few exceptions.

For equipment required by design to perform its safety-related function within a short time period into the design basis event (that is, within seconds or minutes), and having completed its function, subsequent failure is shown not to be detrimental to plant safety, margin by percentage of additional time or equivalent time-temperature is not applied. Margins for trip function requirements are contained in the worst-case high-energy line break envelope. Test parameters are simulated on a real-time basis with the transient condition margins listed in Table 3D.4-3. Trip signals, once generated by the sensors, are locked in by the protection system and do not reset in the event of subsequent sensor failure.

3D.4.8.3 Radiation

An additional 10 percent is added to the calculated total integrated dose in specifying the test requirements.

3D.4.8.4 Seismic Conditions

Required response spectra included in subsection 3.7.2 or other AP1000 program specifications are the conditions to be enveloped. No amplitude margin is added to these conditions. Peak broadening is also discussed in subsection 3.7.2. Seismic qualification by analysis addresses margin requirements by other methods of conservatism while using the same sets of requirements - no amplitude margin is included. For qualification tests, the test facility increases the amplitude of seismic profiles by 10 percent to incorporate margin.

For most applications, considerable margin exists with respect to the acceleration levels employed and the width of the response spectra. Further details are addressed in Attachment E.

3D.4.8.5 High-Energy Line Break Conditions

The envelopes specified for high-energy line breaks are selected to encompass the transients resulting from a spectra of loss of coolant accidents and high-energy line break sizes and locations, and various nodes in the containment. As a consequence, these design envelopes already contain significant margin with respect to any transient corresponding to a single break.

The AP1000 equipment qualification methodology requires that the qualification envelopes be derived with a margin of 15°F and 10 psi with respect to the design envelopes in Figures 3D.5-2 and 3D.5-3. The margin on dose is identified by comparing the location specific dose requirements and the AP1000 equipment qualification parameters.

The alkalinity of the chemistry is increased by 10 percent with respect to the peak value determined for the AP1000 containment sump conditions.

3D.4.9 Treatment of Failures

The primary purpose of equipment qualification is to reduce the potential for common mode failures due to anticipated environmental and seismic conditions. The redundancy, diversity, and periodic testing of nuclear power plant safety-related equipment are designed to accommodate random failures of individual components.

Where an adequate test sample is available, the failure of one component or device together with a successful test of two identical components or devices indicates a random failure mechanism, subject to an investigation concluding that the observed failure is not common mode. Where insufficient test samples prevent such a conclusion, any failures are investigated to ascertain whether the failure mechanism is of common mode origin. Should a common mode failure mechanism be identified as causing the failure, either a design change is implemented to eliminate the problem or a repeat test completed to demonstrate compliance with the criteria.

For those mild environment equipment items that, through a review of available documentation, are subject to failure during a seismic event due to significant aging mechanisms, the material or component is replaced or monitored through a maintenance/surveillance program.

3D.4.10 Traceability

A system of baseline design documentation is instituted to control the design, procurement, and manufacturing of safety-related products. As part of this quality control program, critical parts are identified and assigned a level of control to reflect the estimate of potential qualification or procurement problems. In addition, levels of quality inspection are also assigned to each part. The baseline design documentation describes the equipment in sufficient detail (drawing number, part number, manufacturer) to establish traceability between equipment shipped and equipment tested in the qualification program.

3D.4.10.1 Auditable Link Document

The purchaser of equipment referencing this program requires an auditable link document that provides a tie between the specific equipment and documentation of qualification reviewed for acceptance under this program. This auditable link document includes one or more of the following sections, as applicable.

3D.4.10.1.1 Equipment Link

This documentation certifies that the plant specific equipment is covered by the applicable equipment test reports. This link reflects a comparison of the as-built drawings, baseline design document or other documentation of the tested equipment to the specific equipment.

3D.4.10.1.2 Component Link

This documentation certifies that the components (for example, replacement parts) used in the specific equipment are represented in the applicable test reports or via analysis under a component aging program, such as that described in Attachment B (Subprogram B). This link applies only to equipment whose equipment qualification data package references a component testing program.

This link reflects a comparison of the as-built drawings, baseline design document, or other documentation of the specific equipment to the component program listing.

3D.4.10.1.3 Material Link

This documentation certifies that the materials used in the equipment are represented in a materials aging analysis, such as that described in Attachment B, (Subprogram B). This link applies only to equipment whose equipment qualification data package references the materials aging analysis and reflects a comparison of the as-built drawings, baseline design document, or other documentation of the plant specific equipment to the materials aging analysis listing.

3D.4.10.2 Similarity

Where differences exist between items of equipment, analysis may be employed to demonstrate that the test results obtained for one piece of equipment are applicable to a similar piece of equipment. Documentation of this analysis conforms with guidelines in IEEE 323 and 627, and subsection 3D.6.2.1 and Section 3D.7 of this appendix.

3D.5 Design Specifications

The conditions and parameters considered in the environmental and seismic qualification of AP1000 safety-related equipment are separated into three categories: normal, abnormal, and design basis event. Normal conditions are those sets and ranges of plant conditions that are expected to occur regularly and for which plant equipment is expected to perform its safety-related function, as required, on a continuous, steady-state basis. Abnormal conditions refer to the extreme ranges of normal plant conditions for which the equipment is designed to operate for a period of time without any special calibration or maintenance effort. Design basis event conditions refers to environmental parameters to which the equipment may be subjected without impairment of its defined operating characteristics for those conditions.

The following subsections define the basis for the normal, abnormal, design basis event, and post-design basis event environmental conditions specified for the qualification of safety-related equipment in the AP1000 equipment qualification program. (These are cited in Section 1.7 of each equipment qualification data package; See Attachment A.)

The service conditions simulated by the test plan are identified in equipment qualification data package Section 3.7. (See subsection 3D.7.4.6 and Attachment A.) In general, the parameters employed are selected to be equal to (normal and abnormal) or have margin (design basis event and post-design basis event) with respect to the specified service conditions of equipment qualification data package, Section 1.7, as recommended by IEEE 323. These conditions are conservatively derived to allow for possible alternative locations of equipment within the plant.

3D.5.1 Normal Operating Conditions

Equipment not subject to high-energy line break environments is qualified for normal and abnormal conditions, as applicable, employing a cyclic test sequence of environmental and electrical extremes. A typical test profile, including voltage and frequency cycling, is shown in Figure 3D.5-1.

3D.5.1.1 Pressure, Temperature, Humidity

The calculated values for temperature, pressure, and humidity during normal operation are specified in Table 3D.5-1 as a function of in-plant location.

3D.5.1.2 Radiation Dose

The normal operating dose rates and consequent 60-year design expectation doses at various locations inside containment are specified in Table 3D.5-2. These values have been derived from theoretical calculations assuming an expected 60 years of continuous operation with a reactor power of 3468 MWth (including 2-percent power uncertainty) and steady-state operating conditions. Equivalent data at various locations outside containment are also specified in Table 3D.5-2.

The total integrated dose employed for testing is a combination of normal and accident doses (where applicable), and is defined to equal or exceed the maximum radiation dose contained in the equipment qualification data package. (See Section 3D.7 and Attachment A.) A margin of 10 percent is included in defining the total integrated doses for testing. Normal operating and accident gamma doses are simulated using a cobalt-60 or spent fuel source. The test dose is applied at a rate approximate to the maximum accident dose rate. Irradiation dose rates less than the maximum are considered where there is significant shielding (greater than two mm of steel) or where the peak in-containment design basis event dose rate is not expected to affect the equipment's electrical performance.

Low radiation dose rates encountered during normal operation for most equipment are not considered critical parameters because of the resultant low total integrated dose (10^4 to 10^5 rads) achieved. For equipment not required post-accident, material can be selected based on previous test results. Another test on the completed assembly is not required.

If equipment is located in an environment where the normal total integrated dose exceeds the threshold for radiation damage, then testing is required. For equipment required post-accident, the dose received during normal operation is usually an insignificant part of the total integrated dose, including accident conditions effects. The supposition that a concern over low dose rate effects diminishes as the total integrated dose decreases is supported by Sandia National Laboratories tests (References 6 and 7) on selected materials over a range of dose rates. These studies indicate that reduction in original properties is about the same (and not significant) for dose rates up to a total integrated dose in the megarad range. Although these tests were not performed at dose rates as low as those expected in a nuclear power plant and electrical properties were not evaluated, they do give some indication of the effect of varying the rate.

Based on results of research programs to date and low total integrated dose reached during normal operation, the AP1000 equipment qualification program does not consider degradation due to low dose rate effects to be a significant concern. Therefore, the program does not include any action other than inspecting organic material degradation in the plant through normal maintenance.

3D.5.2 Abnormal Operating Conditions

Abnormal environments are defined to recognize possible plant service abnormalities that lead to short-term changes in environments at various equipment locations.

For equipment located inside containment, several abnormal environment types are considered in subsection 3D.5.2.1. Equipment located outside containment is addressed in subsection 3D.5.2.2.

3D.5.2.1 Abnormal Environments Inside Containment

In the AP1000 equipment qualification program there are multiple events postulated at least once over the 60 year design expectation which cause abnormal environmental conditions in the containment. These are divided into two groups of events, based on peak containment temperatures expected.

Group 1: 150°F Events

- Loss of a fan cooler
- Loss of all ac for up to 2 hours
- Pressurizer safety valve open/close during reactor coolant system transient.

Group 2: 240°F Events

- Spurious automatic depressurization system (ADS) actuation
- Passive residual heat removal (PRHR) system use (long-term)
- Reactor coolant system depressurization via pressurizer safety valve
- Small loss of coolant accident.

Table 3D.5-3 presents the conditions associated with each of these abnormal environment events. Plant recovery occurs after each event with varying degrees of time and maintenance efforts. Thus, the conditions resulting from these events are considered in the development of aging test parameters. Event frequency, conditions, and duration are accounted for within the context of the qualified life objective of each equipment type test program.

Submergence of some equipment during certain spurious automatic depressurization system actuation scenarios is addressed by testing. Submergence testing associated with high-energy line break conditions, (subsection 3D.5.5.1.7) envelops the submergence conditions associated with abnormal environments.

3D.5.2.2 Abnormal Environments Outside Containment

Figure 3D.5-1 represents the assumptions made in defining potential abnormal environments due to loss of air-conditioning or ventilation systems.

Table 3D.5-4 defines the abnormal environments as a function of equipment location. The assumed duration of the abnormal conditions specified in Table 3D.5-4 are consistent with operating practices and technical specification limits. For certain plant applications, qualification

for abnormal environments is not necessary when equipment is located in environmental zones that do not exceed manufacturer's design limits for equipment operation.

3D.5.3 Seismic Events

See Attachment E.

3D.5.4 Containment Test Environment

Regulatory Guide 1.18 specifies that containment integrity is demonstrated at 1.15 times design pressure. The design pressure of the AP1000 containment is 59 psig. Consequently, the maximum pressure specified for the containment test is 59 x 1.15 = 67.85 psig. Other environmental parameters (such as temperature and humidity) of the containment test are adequately enveloped by the parameters specified for normal or abnormal plant conditions.

3D.5.5 Design Basis Event Conditions

Performance requirements are specified for those design basis events for which the equipment performs a safety-related function and which have a potential for changing the equipment environment due to increased temperature, pressure, humidity, radiation, or seismic effects. The environmental conditions for each applicable design basis event are summarized in Table 3D.5.5 and are defined in the equipment qualification data package (see Section 1.8 of Attachment A) based on considerations and assumptions described in the following subsections.

3D.5.5.1 High-Energy Line Break Accidents Inside Containment

3D.5.5.1.1 Radiation Environment – Loss of Coolant Accident

The radiation exposure inside the containment is conservatively estimated by considering the dose in the middle of the AP1000 containment with no credit for the shielding provided by internal structures.

Sources are based on the emergency safeguards system core thermal power rating and the following analytical assumptions:

- Power Level (including 2-percent power uncertainty) .... 3,468 MWt

- Fraction of total core inventory released to the containment atmosphere:

  Noble Gases (Xe, Kr).. 1.0
  Halogens (I, Br) 0.40
  Alkali Metals (Cs, Rb) 0.30
  Tellurium Group (Te, Sb, Se) 0.05
  Barium, Strontium (Ba, Sr)... 0.02
  Noble Metals (Ru, Rh, Pd, Mo, Tc, Co) 0.0025
  Lanthanides (La, Zr, Nd, Eu, Nb, Pm, Pr, Sm, Y, Cm, Am)...................... 0.0002
  Cerium Group (Ce, Pu, Np)... 0.0005

The radionuclide groups and elemental release fractions listed above are consistent with the accident source term information presented in NUREG-1465 (Reference 8), "Accident Source Terms for Light-Water Nuclear Power Plants – Final Report."

The timing of the releases are based on NUREG-1465 assumptions. The release scenario assumed in the calculations is described below.

An initial release of activity from the gaps of a number of failed fuel rods at 10 minutes into the accident is considered. The release of 5 percent of the core inventory of the volatile species (defined as noble gases, halogens, and alkali metals) is assumed. The release period occurs over the next 30 minutes, that is, from 10 to 40 minutes into the accident. At this point, 5 percent of the total core inventory of volatile species has been considered to be released.

Over the next 1.3 hours, releases associated with an early in-vessel release period are assumed to occur, that is, from 40 minutes to 1.97 hours into the accident. This source term is a time-varying release in which the release rate is assumed to be constant during the duration time. Additional releases during the early in-vessel release period include 95 percent of the noble gases, 35 percent of the halogens, and 25 percent of the alkali metals, as well as the fractions of the tellurium group, barium and strontium, noble metals, lanthanides, and cerium group as listed above.

There is no additional release of activity to the containment atmosphere after the in-vessel release phase.

The above source terms are consistent with the guidance provided by the NRC in Regulatory Guide 1.183 for design basis accident (DBA) loss-of-coolant accident (LOCA) evaluations.

Based on these assumptions the instantaneous and integrated gamma and beta doses for the containment atmosphere following a loss of coolant accident are shown in Figures 3D.5-2 and 3D.5-3, respectively.

The total integrated dose of radiation employed for testing is a combination of normal and design basis event dose, as applicable. It is defined to equal or exceed the maximum radiation dose contained in the specification (Attachment A, Section 1.8.4.). A margin of 10 percent is included in defining the total integrated dose for testing. Normal operating and design basis event gamma doses are simulated using a cobalt-60 source. The test dose is applied at a rate approximate to the initial phase of the design basis event dose rate shown in Figure 3D.5-2 as modified by shielding effects (typically 0.2 to 0.25 Mr/hr).

Where exposed organic material is evaluated by test for the effect of (accident) beta radiation, a beta source is employed. Or a cobalt-60 or spent fuel source is used to impart the same dose using gamma radiation. When doing beta equivalent testing, the total integrated dose using gamma is conservatively equal to the beta total integrated dose, or the resulting bremsstrahlung is calculated and the test item is exposed to an equivalent gamma dose.

Radiation conditions for loss of coolant accident envelop other scenarios, such as rod ejection.

3D.5.5.1.2 Radiation Environment – Steam Line Break Accident

Sources associated with a steam line break accident are based on the release of reactor coolant system activity, assuming operation with the design basis fuel defect level of 0.25 percent. It is further assumed that an iodine activity spike increase occurs, which increases the reactor coolant activity during the accident by the maximum of:

- 60 times the maximum allowed by technical specifications, or
- At a rate 500 times the normal rate.

The activity inventory is instantaneously released into the containment atmosphere. The dose is conservatively estimated by considering the dose rate in the middle of the containment, with no credit for the shielding provided by the internal structures, components, and equipment. The instantaneous and integrated gamma and beta doses for the containment atmosphere following a steam line break are shown in Figures 3D.5-4 and 3D.5-5, respectively.

3D.5.5.1.3 Radiation Environment – Feedline Break

For convenience and simplicity, it is conservatively assumed that the radiation doses resulting from a feedline break are equal to the values specified in Figures 3D.5-4 and 3D.5-5 for a steam line break.

3D.5.5.1.4 Total Integrated Dose Specification

The applicable accident doses specified in equipment qualification data package subsection 1.7.4 of Attachment A, have been derived based upon the time required to perform the specified safety function in the accident environment (Attachment A, subsection 1.6.1) and the dose calculations described previously, subject to the following modifications:

- In the general area between the loop compartment wall and containment vessel the gamma dose levels are calculated to be a factor of 2.7 less to allow for the effects of shielding in this area.

- For equipment only required to provide trip or activation functions after accidents involving no release of radioactive material for at least one hour, the radiation dose is based on the normal dose rates (Table 3D.5-2).

3D.5.5.1.5 Temperature/Pressure Environments

The design basis events addressed are the loss of coolant accident, steam line break and feedwater line break. The WGOTHIC code is utilized to calculate the temperature and pressure conditions resulting from these breaks. To retain the option of qualifying equipment for each of these high-energy line break conditions, as applicable, separate environmental containment envelopes are specified for the higher irradiation/lower saturated temperature conditions of the loss of coolant accident (Figures 6.2.1.1-7 and 6.2.1.1-10) as against the lower irradiation/short-term superheated temperature conditions associated with the steam line break (Figures 6.2.1.1-1 and 6.2.1.1-2). To limit the number of basic envelopes, this latter envelope is conservatively employed to define the containment environmental envelope following a feedline break.

Additionally, to facilitate AP1000 generic qualification and testing, the environmental envelopes specified in Figures 6.2.1.1-1, 6.2.1.1-2, 6.2.1.1-7 and 6.2.1.1-10 have been combined to a single high-energy line break profile depicted in Figure 3D.5-8. This combined profile encompasses all locations inside containment on the basis of the containment analyses for the AP1000 design. The profile is used to qualify equipment for any application or location for the AP1000 consistent with the NRC requirements in 10 CFR 50.49 and IEEE 308, 323, 603, and 627, via conformance with IEEE 323 guidelines.

Qualification tests to high-energy line break conditions are designed to address the applicable specified environment(s) with a margin of 15°F and 10 psi. Separate envelopes (Figures 6.2.1.1-1, 6.2.1.1-2, 6.2.1.1-7 and 6.2.1.1-10) with margin are employed, or a combined loss of coolant accident/steam line break/feedwater line break envelope (Figure 3D.5-8) may be employed for in-containment equipment qualification tests. The simulated post-design basis event aging time-temperature profile (Figure 3D.5-8 from 24 hours to test conclusion) is defined consistent with the smallest value of activation energy applicable to the thermal aging sensitive components composing the test equipment or by a demonstrably conservative activation energy, as described in Attachment D.

3D.5.5.1.6 Chemical Environment

The high-energy line break test will include chemical injection during the first 24 hours of the test, to simulate the reactor coolant system fluid. Initial pH is from 4 to 4.5, with the solution consisting primarily of boric acid.

Since there is no caustic containment spray in the AP1000, subsequent adjustments in pH may not be necessary for all tests. Sump solution chemistry is adjusted by release of alkaline chemistry, which will rise to 7.0 to 9.5 within a few hours of containment flooding. These conditions are simulated for submerged equipment.

Margin in low pH value is not included, but is addressed by the continued injection through the first 24 hours. Margin in alkaline pH, where adjustment is necessary, is incorporated by a 10 percent increase in alkalinity.

3D.5.5.1.7 Submergence

Performance of equipment in a submerged condition is verified by a test that replicates the actual conditions with appropriate margin.

3D.5.5.2 High-Energy Line Break Accidents Outside Containment

For the majority of equipment located outside containment, the normal operating environment remains unchanged by a high-energy line break accident. As a consequence, qualification for such events is covered by qualification for normal conditions.

A limited amount of equipment located outside containment, near high-energy lines, could be subject to local hostile environmental conditions because of a high-energy line break outside containment. In this case, the equipment is qualified for the conditions resulting from events affecting its location and for which it is required to operate. These conditions are shown in

Figure 3D.5-9. Sheet 1 shows the combined design and test conditions for equipment that is required to perform throughout all postulated events where superheat is delayed past five minutes. Sheet 2 shows the combined design and test conditions for equipment that is only required to perform for the first five minutes into the event. The maximum pressure for any event outside containment is less than 6 psig.

3D.6 Qualification Methods

The recognized methods available for qualifying safety-related electrical equipment are established in IEEE 323. These are type testing, operating experience, analysis, on-going qualification, or a combination of these methods. The choice of qualification method for a particular item of equipment is based upon many factors. These factors include practicability, size and complexity of equipment, economics, and availability of previous qualification to earlier standards.

The qualification method employed for each equipment type included under the AP1000 equipment qualification program is identified in the individual equipment qualification data packages whether by test (Attachment A, Section 3.0), experience (Attachment A, Section 3.0), analysis (Attachment A, Section 5.0), or by a combination of these methods. The AP1000 equipment qualification program may employ on-going qualification through the use of maintenance and surveillance. Guidance for such an approach is not included in this appendix.

3D.6.1 Type Test

The preferred method of environmental and seismic qualification of safety-related electrical and electromechanical equipment for the AP1000 equipment qualification program is type testing according to the guidelines and requirements of IEEE 323-1974 and 344-1987. Development of type test requirements are discussed in Section 3D.5. Documentation requirements and test plan development are addressed in Section 3D.7.

Additionally, qualification based on type tests performed according to IEEE 323 and 344, but not specifically for the AP1000, may be used as a qualification basis. Section 3D.6.5 of this appendix discusses the combination of qualification methods as they apply to the AP1000 equipment qualification program. (See subsection 3D.6.5.1.)

3D.6.2 Analysis

The AP1000 equipment qualification program uses analysis for seismic qualification of equipment if the primary requirement is the demonstration of structural integrity during a seismic event. For equipment that performs an active or dynamic function, seismic qualification by analysis may also be used. However, the similarity between a qualified test unit and an as-supplied unit must be demonstrated. (See Section E.3 of Attachment E.) subsection 3.9.2.2 describes the qualification requirements for safety-related mechanical equipment where a fluid pressure boundary is involved. For those mechanical components that are not pressure boundaries, analysis is performed in compliance with the applicable industry design standard. Where age-sensitive materials, such as gaskets and packing, are used in the assembly of mechanical equipment, the aging of these materials is normally evaluated based on an item-by-item review of the aging characteristics of the material. (See subsection 3D.6.2.3.)

The AP1000 equipment qualification program does not establish seismic and environmental qualification of Class 1E electrical or electromechanical equipment for design basis event conditions on the bases of analyses alone. Analysis is employed to supplement testing or to provide verification that the test results are applicable. The following subsections provide examples of the necessary and sufficient conditions under which analysis will be applied in the qualification of safety-related equipment for the AP1000.

Requirements for documentation of the analysis are further treated in Section 3D.7.

3D.6.2.1 Similarity

Similarities among manufacturer's models provides several options for extending qualification to equipment without the need for a complete qualification test program.

A model series, such as that for a solenoid valve design, consists of numerous models that are identical in materials of construction and manufacturing process, but have minor variance in size, functional mode, operating voltage, electrical termination type, and mechanical interface sizing. Such variances in most cases have no impact on or relevance to the capability of the various models to perform acceptably under environmental or seismic (or both) qualification test conditions. Furthermore, the design basis document may apply equally to each member of the model series. In such cases, all members of the model series can be qualified by reference to the same testing or analysis.

There may be sufficient similarities between different model series to justify the case for similarity. A documented comparison addressing differences in the design for each, or apparent physical differences between members of each model series, may be sufficient to preclude the testing of one model series based on the testing of the other.

Similarly, different models of a manufacturer's transmitters may be identical in some respects but different in others. The justification of similarity addresses the degree of similarity for critical characteristics. Differences that are not significant to qualification are also addressed for completeness. The mechanical and electrical functional modes and configurations must be the same. The materials of construction may be different, but must demonstrate equivalent performance. Other means of assuring accuracy may be necessary. When the devices are sufficiently similar in all attributes affecting qualification, qualification testing of one item can adequately cover another.

3D.6.2.2 Substitution

The objectives are to establish a degree of similarity and equivalence of performance for parts and materials that are different and, ultimately, to preclude the need for testing. For example, a gasket material is changed or a new type of capacitor is used because the original is no longer available, economical, or inadequate. Substitution of parts and materials is acceptable if comparison or analysis supports the conclusion that equipment performance is the same or better as a result. Consideration is given to characteristics of materials and the relative degree to which each is affected (or degraded) by the environmental parameters of qualification.

3D.6.2.3 Analysis of Safety-Related Mechanical Equipment

Environmental qualification of safety-related mechanical equipment is required to preclude common mode failures due to environmental effects of a design basis accident. Requirements are based on GDC 4 and 10 CFR 50, Appendix B. These criteria mandate that safety-related structures, systems, and components be designed to accommodate both normal and accident environmental effects.

3D.6.2.3.1 Equipment Identification

Safety-related mechanical equipment to be qualified is identified through the review of design basis documentation or the requirements of each safety-related fluid system. Only nonmetallic parts or subcomponents within the safety-related mechanical equipment are addressed for the effects of the postulated environments. The principal scope is typically valve "soft parts" that are critical to the valve safety-related function or pressure boundary integrity.

The types of components most frequently encountered in the mechanical equipment evaluations are discussed in subsection 3D.6.2.3.3. Properties of materials that are assessed to provide confidence in safety-related function performance are also identified.

3D.6.2.3.2 Safety-Related Function

Safety-related functions and performance criteria are identified based on system and component classification. Structure, system, and component design basis documentation is reviewed to determine the specific safety functions. Components and subcomponents not involved in the equipment's safety-related function(s) are excluded from the qualification process if it is shown that their failures have no effect on the safety-related functions.

3D.6.2.3.3 Performance Criteria

Comprehensive performance criteria are established to satisfy the fundamental qualification requirements. The criterion for qualification is that the property of the nonmetallic material with regard to its application is not degraded during the specified qualified life to the point that the component is unable to perform its intended safety-related function. Properties for the component types listed in Table 3D.6-1 are discussed as examples.

Gaskets and O-Rings

The capability of gaskets and O-rings to keep their shapes determines their ability to maintain pressure boundaries. When an O-ring or gasket loses its dimensional memory, it does not exert the necessary force on the confining surfaces. This could result in leakage. Compression set and elongation are good indicators of the dimensional memory of a material. They also reflect the extent of thermal aging and radiation-induced cross-linking. A compression set of 50 percent is chosen as a conservative end-of-life criterion even though leakage is unlikely to occur until the component takes a compression set of greater than 75 percent. When compression set data is not available for a gasket or O-ring, elongation at break is the material property evaluated because like compression set, it is an indication of dimensional memory and cross-link.

Diaphragms

Diaphragms must remain flexible yet maintain their dimensional memory throughout the estimated mechanical cycles. Retention of elongation or tensile strength is evaluated for radiation and thermal aging.

Diaphragm Support Sheets

The diaphragm support sheet prevents puncture and tearing of the diaphragm. It is not considered critical to the operability of diaphragm valves. The best indication of radiation damage and thermal aging to diaphragm support materials is retention of elongation.

Lubricants

One of the primary functions of oils and greases is to maintain a thin film barrier between moving parts to reduce friction and wear. Irradiation reduces the capability of a lubricant to perform this function by decreasing viscosity in oils and increasing penetration in greases and finally converting lubricants to hard, brittle solids if exposure is severe.

Worm Gears

Worm gears must be capable of transmitting forces without excessive deformation. Flexural strength is the material property chosen to evaluate radiation and thermal aging resistance of worm gears.

3D.6.2.3.4 Identification of Service Conditions

Service conditions are identified for the normal and accident conditions. The general design of equipment permits exemption of environmental parameters such as pressure and humidity. Where critical parts are totally enclosed by metal and not directly exposed to potentially harsh environments, the effects of humidity and chemical spray are not addressed. The degradation of mechanical equipment due to thermal and radiation aging is typically more severe than the possible degradation due to other environments. Since most mechanical equipment interfaces with process fluid, the effect of the fluid on the environmental conditions (temperature, radiation, and chemical) is considered.

3D.6.2.3.5 Description of Potential Failure

Where applicable, potential failure modes are identified and assessed for the equipment. Assessment of equipment aging mechanisms is essential to determine if aging has a significant effect on operability. This assessment provides confidence that significant aging mechanisms are unlikely to contribute to common-mode failures adverse to the safety-related function of equipment.

3D.6.2.3.6 Qualification Procedure

The nonmetallic materials identified are evaluated to the normal and accident environmental parameters. The evaluation procedure includes the following steps:

- Identification of the environmental effect on the material properties
- Performance of a thermal aging analysis
- Determination of the environmental effects on the equipment safety-related function.

These are detailed in the equipment qualification data package of Attachment A, Section 4.Y.

3D.6.2.3.7 Performance Criteria

The nonmetallic subcomponents of the mechanical equipment:

a. are acceptable for the plant environment by exhibiting threshold radiation values above the postulated environmental condition, and

b. are acceptable for the plant environment by exhibiting a maximum service temperature above the maximum postulated environmental, and

c. does exhibit a service life sufficient to survive the accident duration, or

d. instead of a, b, and c, are acceptable for the plant environment by analysis that demonstrates that the safety-related function of the component is not compromised.

The mechanical equipment is considered qualified if subcomponents important to the safety function are acceptable.

Nonmetallic subcomponents not meeting the criteria must have a replacement interval specified to maintain the qualification of the affected equipment. The replacement interval is determined by analysis and documented.

3D.6.2.3.8 Equipment Qualification Maintenance Requirements

The maintenance requirements resulting from the activities described herein are identified. The qualification maintenance requirements are based on the following:

- Qualification evaluation results (for example, periodic replacement of age-susceptible parts before the end of their qualified lives)
- Equipment qualification-related maintenance activities derived from the qualification report(s)
- Vendor recommended equipment qualification maintenance. Vendor recommended maintenance is included if it is required in order to maintain qualification.

3D.6.2.3.9 Qualification Documentation

The qualification of the mechanical equipment to the postulated environments is documented in an auditable form. See subsection 3D.7.

3D.6.3 Operating Experience

Qualification by experience is typically not employed in the AP1000 equipment qualification program as a prime method of qualification. Operating experience provides supportive evidence to the prime method of qualification. For those instances where seismic experience data are to be used, the Combined License applicant will provide documentation of the methodology. Where such information is provided, it is demonstrated that the experience is applicable to the safety-related functional requirements of the equipment. This demonstration of applicability includes an evaluation of operating environments, mountings, performance requirements, and performance history. Requirements for the documentation of qualification via experience is discussed in subsection 3D.7.6.

3D.6.4 On-Going Qualification

The AP1000 equipment qualification program may employ on-going qualification through special maintenance and surveillance activities. However, this method of qualification is not suitable as a sole means for qualifying equipment for design basis event conditions. On-going qualification, as a method, is used exclusively for safety-related equipment located in a mild environment area. Such use requires supplementary test, analysis, or experience data to address equipment operability and performance during and after a seismic design basis event.

Documentation requirements for qualification that includes on-going qualification as a method are developed to conform with NRC guidance provided in Regulatory Guide 1.33, Revision 2.

3D.6.5 Combinations of Methods

Qualification by a combination of the preceding methods is used whenever qualification by type test is not the sole basis of qualification under the AP1000 equipment qualification program. If analysis is used, justification includes identifying a test or experience bases, and addressing concerns related to departure from the required type test sequence.

3D.6.5.1 Use of Existing Qualification Reports

Pre-existing qualification programs and documents are used only if the seismic test program satisfies the guidelines of IEEE 344-1987 and the environmental qualification program satisfies the guidelines of IEEE 323-1974.

Qualification test and analysis reports conforming to those IEEE, but not specifically performed to the AP1000 equipment qualification program parameters, may be acceptable as qualification bases. In such cases, supplementary qualification efforts described in subsections 3D.6.2, 3D.6.3, and 3D.6.4 of this appendix may be required to validate acceptability under the AP1000 equipment qualification program. Justifications are documented as analyses, and appear in equipment qualification data package, Section 4.0. (See Attachment A.)

3D.6.5.1.1 Aging

Past qualification tests may provide sufficient basis to preclude new aging simulation testing as part of the AP1000 program. Also, simulation of both electrical and mechanical operational cycling may be waived where existing data demonstrates equipment durability greatly in the excess of the estimated number of operating cycles for Class 1E service. Application of past qualification and other tests is considered in the development of test plans and analysis procedures. The bases and justification is provided in qualification documentation for cases where applicable aging parameters are omitted from the test sequence.

3D.6.5.1.2 Seismic

Seismic qualification generally relies on analyses and justification to verify the adequacy or applicability of generic testing to a particular installed configuration of similar equipment. Analytical methods and documentation guidelines of IEEE 344-1987, as supplemented by Regulatory Guide 1.100, Revision 2, address these needs. Attachment E of this appendix provides the AP1000 equipment qualification program requirements regarding seismic qualification.

3D.6.5.1.3 High-Energy Line Break Conditions

Typically, existing qualification tests address conditions of high-energy line break environments occurring inside containment. These are used where it is demonstrated that the qualification envelops the applicable requirements.

3D.7 Documentation

The AP1000 equipment qualification program documentation consists principally of three types of documents:

- "Methodology for Qualifying AP1000 Safety-Related Electrical and Mechanical Equipment" is the generic program "parent" document. It describes the methods and practices employed in the AP1000 equipment qualification program.

- Equipment qualification data packages are "daughter" documents to the methodology. Each is a summary of the qualification program for a specific equipment type (for example, a particular model or design series of a manufacturer, an as-provided system, or a family of equipment tested as a set). The equipment qualification data package defines the qualification program objectives, methods, applicable equipment performance specifications, and the qualification plan. It provides a summary of the results.

- Equipment Qualification Test Reports (EQTRs) are the reports that present specific methods used during the qualification process and the results of that process.

The equipment qualification data packages are developed separate from the parent document. Similarly, the equipment qualification test reports are developed separate from the equipment qualification data packages. Equipment qualification test reports used in the AP1000 equipment qualification program may include existing reports of testing or analysis that comply with the relevant aspects of this methodology. Information necessary to demonstrate the equipment's

capability to perform its intended safety-related function(s) while exposed to normal, abnormal, accident, and post-accident environments is provided in or referenced by the equipment qualification data package. If maintenance, refurbishment, or replacement of the equipment is necessary to provide confidence in the equipment's capability to perform its safety function, this information is also included in the equipment qualification data package. Data, in raw form, cited in the equipment qualification data packages or equipment qualification test reports is available for audit for the life of the plant.

3D.7.1 Equipment Qualification Data Package

Attachment A contains sample of the equipment qualification data package format. Each equipment qualification data package consists of the following elements:

Section 1.0 – Specifications
Section 2.0 – Qualification Program
Section 3.0 – Qualification by Test
Section 4.0 – Qualification by Analysis
Section 5.0 – Qualification by Experience
Section 6.0 – Qualification Program Conclusions
Table 1 – Qualification Summary

The following paragraphs discuss the six sections in the equipment qualification data packages.

3D.7.2 Specifications

Section 1.0 of the equipment qualification data packages (Attachment A) contains the performance specification of the equipment. This specification establishes the necessary parameters for which qualification is demonstrated. The basic criterion for qualification is that the safety-related functional requirements defined in Section 1.0 are successfully demonstrated, with margin, under the specified environmental conditions.

The following sections define the bases on which the parameters contained in Section 1.0 are selected.

3D.7.2.1 Equipment Identification

Equipment is identified in Section 1.1 of Attachment A by manufacturer, model or model series, and reference to other documents describing or depicting its construction, configuration, and modifications that are uniquely necessary after manufacture to its application in the AP1000 plant design. Model series (for example, a limit switch design family) and other pertinent details on items making up the equipment type qualified are compiled as a table and referenced from this section.

3D.7.2.2 Installation Requirements

So that the qualification represents the in-plant condition, the method of installation, as specified in Section 1.2 of Attachment A, is in accordance with the supplier's installation instructions. Differences unique to safety-related applications in the AP1000 design are included, with

appropriate reference to drawings, technical manual supplements, or mandatory modification packages.

3D.7.2.3 Electrical Requirements

The pertinent electrical requirements are specified (for example, voltage, frequency, load) in this section. Also included is any variation in the defined parameters for which the equipment is to perform its specified functions (Section 1.3 of Attachment A).

3D.7.2.4 Auxiliary Devices

Sometimes the equipment qualified relies upon the operation of auxiliary devices in order to perform the specified safety-related functions. These devices are identified in Section 1.4 of Attachment A. Auxiliary devices include items such as electrical conductor seal assemblies that, in service, become part of the qualified equipment's pressure boundary. The applicable equipment qualification data package for the auxiliary device(s) is specified, if known.

3D.7.2.5 Preventive Maintenance

Preventive maintenance (Section 1.5 of Attachment A) to be performed includes maintenance or periodic activities assumed as part of the qualification program or necessary to support qualification. Only those activities that are required in order to support qualification or the qualified life are specified. The manufacturer's recommended maintenance activities are considered to determine that there is no adverse impact to qualification or the maintenance of qualified life. Likewise, manufacturer's recommendations for maintenance or surveillance activities necessary to support operability are identified, or reference is made to the appropriate technical manual or supplements.

"None" means that maintenance is not essential to qualification or the qualified life of the equipment. However, this should not preclude development of a preventive maintenance program designed to enhance equipment performance and to identify unanticipated equipment degradation as long as such a program does not compromise the qualification status of the equipment. Surveillance activities may also be considered to support a basis for and a possible extension of the qualified life.

3D.7.2.6 Performance Requirements

Section 1.7 of Attachment A contains a tabulation of performance requirements for each safety-related function for which the equipment is qualified. Several such sections or tables may be necessary when the equipment is qualified for applications where the performance requirements vary. Performance requirements are stated regarding the normal and abnormal environmental conditions applicable at the location where the equipment is installed. Similarly, each design basis event and the subsequent post-event period is included in the table.

Margin is not included in the performance requirements except by conservatism in their determination.

3D.7.2.7 Environmental Conditions

Within each set of performance requirements, a set of environmental parameters is specified in section 1.8 of Attachment A, also in tabular form. Parameters are based on the equipment location and function and include those addressed in other sections of this appendix.

Margin is not included in the environmental parameters except by conservatism in their determination. The objective is to provide the baseline reference onto which margin is added.

3D.7.3 Qualification Program

An overview of the qualification program and its objective is presented in narrative form in Section 2.0. Attachment A includes a table to be completed as a graphic reference. As it is assumed that tests, analyses, or some combination of the two are the principal methods of qualification, columns are included for each. Other methods, when used, are summarized in brief notes appended to the table.

References to reports of testing, analysis, or other information considered in support of the qualification program are compiled in Section 2.2 of Attachment A. This includes any technical manuals, drawings, and supporting material cited or referenced by text throughout the equipment qualification data package.

3D.7.4 Qualification by Test

Qualification by test is selected as the primary method of qualification for complex equipment not readily amenable to analysis or for equipment required to perform a safety-related function in a high-energy line break environment. The proposed test plan is identified in Section 3.0 of Attachment A. Where supportive analysis or experience is claimed as an integral part of the qualification program, cross reference is provided to Attachment A Section 4.0 or Section 5.0 or both for those aspects of the qualification not covered by the test plan. The following sections establish the basis on which the information specified in Section 3.0 is selected.

3D.7.4.1 Specimen Description

The equipment qualified is identified, including the baseline design document number/reference, where applicable, the equipment type, manufacturer and model number, in Section 3.1 of Attachment A. When testing a model series (or equipment families), the representative items tested are clearly identified. The basis of their representation should be included.

Section 3.1 is primarily intended to identify test specimens used in a test supporting the qualification program. But it also discusses the specimens considered for other methods used in the qualification program.

3D.7.4.2 Number Tested

The test program is based upon selectively testing a representative number of components according to type, size, or other appropriate classification, on a prototype basis. The number of

items of equipment representative of the equipment type that are tested is defined in Section 3.2 of Attachment A.

3D.7.4.3 Mounting

The method of mounting the equipment for the test is identified in Section 3.3 of Attachment A. The in-plant installation requirements, as specified by the supplier under Section 1.2 of Attachment A, are fully represented.

3D.7.4.4 Connections

The equipment connections necessary to demonstrate safety-related functional operability during testing are identified in Section 3.4 of Attachment A. This includes items that are part of the installed configuration, but are not part of the test apparatus.

Particularly important are items that are included by "practice of good workmanship," such as pipe thread sealant. Another example is the use of electrical connection sealing materials. Where these items are included in the testing, they become factors in the performance of the equipment, especially under aggressive or adverse environmental conditions. Their thermal degradation and sensitivity to irradiation and chemistry environments are considered in the qualification program, both for impact to equipment performance under harsh conditions and for their contribution to equipment qualified life.

3D.7.4.5 Test Sequence

The preferred test sequence specified in Attachment A, Section 3.5 is the one recommended by IEEE 323-1974. The qualification test sequence used is specified in Section 3.6 of Attachment A. Justification for departures or additions to the preferred test sequence are included. Also, any portion of the test sequence that is supplemented by analysis or other methods is identified for completeness.

3D.7.4.6 Simulated Service Conditions

The service conditions simulated by the test plan are identified in Attachment A, Section 3.7. In general, the parameters employed are selected to be equal to (normal and abnormal) or have margin (accident and post-accident) with respect to the specified service conditions of Attachment A, Section 1.8. Criteria for margin is detailed in Section 3D.4.8.

3D.7.4.7 Measured Variables

The parameters measured during the specified test sequence in order to demonstrate qualification for the performance specification (Attachment A, Section 1.0) are individually listed in Attachment A, Section 3.8 of Attachment A. This section is formatted to include parameters relevant to the test environment and the electrical and mechanical characteristics of equipment operation. Other characteristics unique to a particular test or equipment type are included, when applicable.

3D.7.4.8 Type Test Summary

Section 3.9 of Attachment A provides a narrative summary of the qualification tests and results. The applicable test reports are provided as references in Attachment A, Section 2.2. Test data is available for audit throughout the operation of the plant.

Each test report referenced by the equipment qualification data package should contain information cited in the preceding section, as well as the following:

- The test facility, location, and a description of the test equipment used. Monitoring equipment should have current calibration traceable to the National Bureau of Standards.
- Test setup and specimen installation details.
- Description of the mounting conditions simulated during the test program and any difference between them and the mounting details shown on the equipment drawings, with qualification of any differences found.
- Description of limitations on the use and mounting of the qualified equipment found as a result of the qualification test program.
- Description of the test method and the justification that the method meets the specification test requirements.
- Description of operational settings used to demonstrate functional operability and any limitation imposed on them.
- Test records (for example, test response spectra, time history; accident transient parameters - temperature, pressure). This includes performance and operability test results, inspection results, and the monitored test and specimen and calibration records of instruments used.
- Record of compliance of test results with the seismic qualification criteria.
- Description of anomalies found during the test program, and their resolution(s).

Potential aging mechanisms resulting from significant in-service thermal, electrical, mechanical, radiation, and vibration sources are identified in subsection 3.9.3 of Attachment A. When aging is addressed as part of the test sequence, the method employed for aging the equipment is indicated and is chosen to conservatively simulate the potential aging effects resulting from the operating cycles and environmental conditions specified in Attachment A, Section 1.0. The methods employed to address each of the potential aging mechanisms are discussed.

3D.7.5 Qualification by Analysis

Qualification by this methodology does not rely solely on analyses. Generally, analysis is permitted to support qualification testing or to establish that testing of other sufficiently similar equipment can be cited to establish or extend the qualification of equipment covered by the equipment qualification data package.

The sample format for Section 4.0 of Attachment A is formatted to conform with the recommendations of IEEE 323-1974. Each subsection addresses a particular analysis if more than one is performed to support qualification. Not all subsections identified in the sample format apply to any particular analysis. Documentation of analyses demonstrating or supporting seismic qualification conforms with the guidelines of Attachment E and the recommendations of IEEE 344-1987.

3D.7.6 Qualification by Experience

When experience data are used for or in support of a qualification program, items relevant to its use are detailed in Attachment A, Section 5.0.

3D.7.7 Qualification Program Conclusions

Section 6.0 of Attachment A summarizes the conclusions of the qualification program, including and addressing methods employed and conditions upon which qualification of the equipment is based. Details regarding each aspect of simulated aging are addressed distinctly, with conclusions as to the life-limiting aspects clearly stated.

Conclusions for each design basis event are summarized. Generally, these are combined as either design basis event seismic and design basis event environmental.

3D.7.8 Combined License Information

This section has no requirement for additional information to be provided in support of the Combined License application except for seismic experience qualification methodology if utilized.

3D.8 References

1. IEEE-323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations."

2. IEEE-344-1987, "IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations."

3. IEEE-627-1980, "IEEE Standard for Design Qualification of Safety System Equipment Used in Nuclear Power Generating Stations."

4. NUREG/CR-3156, "A Survey of the State-of-the-Art in Aging of Electronics with Application to Nuclear Plant Instrumentation."

5. EPRI NP-1558, Project 890-1, "A Review of Equipment Aging Theory and Technology."

6. NUREG/CR 2156, "Radiation Thermal Degradation of PE and PVC: Mechanism of Synergism and Dose Rate Effects," Clough and Gillen, June 1981.

7. NUREG/CR 2157, "Occurrence and Implication of Radiation Dose Rate Effects for Material Aging Studies," Clough and Gillen, June 1981.

8. NUREG-1465, "Accident Source Terms for Light-Water Nuclear Power Plants – Final Report," L. Soffer, et al., February 1995.

Note: See subsection 3D.4.1.1 for other IEEE references.

Table 3D.4-1

TYPICAL MILD ENVIRONMENT PARAMETER LIMITS

Parameter	Limit	Notes
Temperature	≤ 120°F	
Pressure	Atmospheric	(Nominal)
Humidity	30 – 65% ≤ 95%	(Typical) (Abnormal)
Radiation	≤ 10^4 rads gamma ≤ 10^3 rads gamma	 (IC electronics and microprocessors)
Chemistry	None	
Submergence	None	

Table 3D.4-2

EQUIPMENT POST-ACCIDENT OPERABILITY TIMES

Equipment	Required Post-Accident Operability	
Equipment necessary to perform trip functions	5 minutes	(Envelopes trip time requirements)
Equipment located outside containment, is accessible, and can be repaired, replaced, or recalibrated	2 weeks	
Equipment located inside containment that is inaccessible and is required for post-accident monitoring	4 months	(This number is based on an acceptable amount of time to be repaired, replaced, or recalibrated, or for an equivalent indication to be obtained.)
Equipment located inside containment, is inaccessible, or cannot be repaired, replaced, recalibrated or equivalent indication cannot be obtained	1 year	
Equipment located in a mild environment following an accident	Various	(Specific as to function, maximum of 1 year)

Table 3D.4-3

AP1000 EQ PROGRAM MARGIN REQUIREMENTS

Condition	Parameter	Required Margin	Notes
NORMAL:	Aging	+10%	+10% time margin, +10% radiation and/or selection of conservative test parameters. Comply with guidance of subsection 3D.4.8.2.
ABNORMAL:	Temperature/ Humidity		Margin is in "time" at abnormal test extremes.
	Pressure	None	Nominally atmospheric.
	Radiation	+10%	Include in aging doses, if applicable.
	Chemical Effects	+10%	In alkalinity of adjusted sump pH. Not applicable outside containment.
	Voltage & Frequency	+/- 10%	Simulated during temperature/humidity test.
	Submergence	Note 1	Generally, precluded by design.
ACCIDENT:	Transient Temperature and Pressure		Temperature (+15°F) and pressure (+10 psig peak) margins added to transient profile.
	Chemical effects	+10%	In alkalinity of adjusted sump pH. Not applicable outside containment.
	Radiation	+10%	Added to calculated total integrated dose.
	Submergence	Note 1	Generally, precluded by design.
	Seismic/ Vibration	+10%	Of acceleration at equipment mounting point for either SSE or line-mounted equipment vibration. (See subsection 3D.4.8.4.)
	Post-accident Aging	+10%	In time demonstrated via Arrhenius time/temperature relationship calculation.

Note:

1. Margin in submergence conditions is achieved by increases in temperature (+15°F), pressure (+10%), and chemistry (+10% in alkalinity of adjusted sump pH). Also, accident conditions submergence testing envelops abnormal conditions submergence conditions.

Table 3D.5-1 (Sheet 1 of 3)

NORMAL OPERATING ENVIRONMENTS

(Notes 1 and 2)

Location/Parameter	**Normal Range**	**Notes**
Zone 1 – Containment (Room numbers: 11000 through 11999)		
Temperature	50° - 120°F	
Pressure	-0.2 - +1.0 psig	
Humidity	0 - 100%	
Radiation	see Table 3D.5-2	
Chemistry	None	
Zone 2 - Auxiliary Building - Non-Radiological - I&C, DC Equipment, RCP Switchgear & Battery rooms, etc. (Room numbers: 12101, 12102, 12103, 12104, 12105, 12111, 12112, 12113, 12201, 12202, 12203, 12204, 12205, 12207, 12211, 12212, 12213, 12301, 12302, 12303, 12304, 12305, 12311, 12312, 12313, 12405, 12412, 12501, and 12505)		
Temperature	67 - 73°F	
Pressure	Slightly positive to slightly negative	
Humidity	10 - 60%	
Radiation	$<10^3$ rads gamma	
Chemistry	None	
Zone 3 - Auxiliary Building - Non-Radiological - Main Control Room (Room number: 12401)		
Temperature	67 - 78°F	
Pressure	Slightly positive	
Humidity	25 - 60%	
Radiation	$<10^3$ rads gamma	
Chemistry	None	
Zone 4 - Auxiliary Building - Non-Radiological - Accessible (Room numbers: 12321, 12421, 12422, 12423)		
Temperature	50 - 105°F	
Pressure	Slightly positive	
Humidity	10 - 60%	
Radiation	$<10^3$ rads gamma	
Chemistry	None	

Table 3D.5-1 (Sheet 2 of 3)

NORMAL OPERATING ENVIRONMENTS

(Notes 1 and 2)

Location/Parameter	**Normal Range**	**Notes**
Zone 5 - Auxiliary Building - Non-Radiological - MSIV Compartments (Room numbers: 12404, 12406, 12504, 12506, 12701)		
Temperature	50 - 130°F	
Pressure	Atmospheric	
Humidity	10 - 100%	
Radiation	<103 rads gamma	
Chemistry	None	
Zone 6 - Auxiliary Building - Radiological - Inaccessible (Room numbers: 12154, 12158, 12162, 12163, 12166, 12167, 12171, 12172, 12254, 12255, 12258, 12262, 12264, 12265, 12354, 12362, 12363, 12365, 12371, 12372, 12373, 12374, 12454, 12462, 12463)		
Temperature	50 - 130°F	
Pressure	Slightly negative to atmospheric	
Humidity	10 - 100%	
Radiation	See Table 3D.5-2	
Chemistry	None	
Zone 7 - Auxiliary Building - Radiological - Accessible (Room numbers: 12151, 12152, 12155, 12156, 12161, 12165, 12169, 12242, 12244, 12251, 12252, 12261, 12268, 12271, 12272, 12273, 12274, 12275, 12341, 12351, 12352, 12361, 12451, 12452, 12461, 12551, 12552, 12553, 12554, 12555, 12561)		
Temperature	50 - 104°F	
Pressure	Atmospheric	
Humidity	10 - 100%	
Radiation	See Table 3D.5-2	
Chemistry	None	
Zone 8 - Turbine Building (Room numbers: 20300 through 20799)		
Temperature	50 - 104°F	
Pressure	Atmospheric	
Humidity	10 - 100%	
Radiation	$<10^3$ rads gamma	
Chemistry	None	

Table 3D.5-1 (Sheet 3 of 3)

NORMAL OPERATING ENVIRONMENTS

(Notes 1 and 2)

Location/Parameter	**Normal Range**	**Notes**
Zone 9 - Auxiliary Building - PCS Valve Room (Room number: 12701)		
Temperature	50 - 120°F	
Pressure	Atmospheric	
Humidity	10 - 100%	
Radiation	See Table 3D.5-2	
Chemistry	None	
Zone 10 - Auxiliary Building - Non-Radiological - Valve/Piping Penetration Room with SG Blowdown (Room number: 12306)		
Temperature	50 - 105°F	
Pressure	Slightly positive	
Humidity	10 - 60%	
Radiation	$<10^3$ rads gamma	
Chemistry	None	
Zone 11 - Auxiliary Building - Radiological - Fuel Handling Area (Room numbers: 12562, 12563, 12564)		
Temperature	50 - 105°F	
Pressure	Slightly negative	
Humidity	10 - 100%	
Radiation	See Table 3D.5-2	
Chemistry	None	

Notes:
1. Room numbers - see Section 1.2, General Arrangement drawings.
2. Relative humidity is not controlled except in the main control room.

Table 3D.5-2

60-YEAR NORMAL OPERATING DOSES

Location	Gamma Dose Rate (Rad air hour)	60-Year Gamma Dose (Rads air)
Inside Containment:		
RCS Pipe - Center	1.9×10^{3}	1.0×10^{9}
RCS Pipe - ID	1.1×10^{3}	5.7×10^{8}
RCS Pipe - OD (contact)	7.8×10^{1}	4.1×10^{7}
RCS Pipe - General Area[b]	4.0×10^{1}	2.1×10^{7}
Outside Loop/Compartment Wall	<0.1	$<5 \times 10^{4}$
Adjacent to Reactor Vessel Wall	4.4×10^{4}	2.7×10^{10}[a]
Outside Containment:		
Penetration Area	--	$<1 \times 10^{6}$
Pump Cubicles	--	$<1 \times 10^{6}$
Radioactive Waste Area	--	$<1 \times 10^{6}$
Radwaste Tank Cubicles	--	$<1 \times 10^{7}$
Other General Areas	--	$<5 \times 10^{2}$

Notes:

a. 60-year integrated neutron dose for E>1 MeV is 6×10^{17} n/cm^2

b. 12 inches from RCS pipe OD

Table 3D.5-3

**ABNORMAL OPERATING ENVIRONMENTS
INSIDE CONTAINMENT**

Conditions/Parameter	Abnormal Extreme	Duration	Notes
Group 1 (150°F) Abnormal Events			
Temperature	150°F	4 hours	Note 1
Pressure	Atmospheric		
Humidity	100%	4 hours	Note 1
Radiation	Same as normal		
Chemistry	None		
Submergence	None		
Group 2 (250°F) Abnormal Events			
Temperature	250°F	30 days	Note 1
Pressure	15 psig	30 days	Note 1
Humidity	100%	30 days	Note 1
Radiation			Note 2
Chemistry	4.0 - 4.5 pH	30 days	Note 3
Submergence		30 days	Note 4

Notes:

1. Parameter value is not maximum for full duration.
2. Minor increase over normal radiation conditions expected.
3. Containment sump pH is adjusted to the range of 7.0 to 9.5, if containment is flooded.
4. While most ADS events are terminated in 40 minutes with only minor flooding, there is the potential for flooding of the containment to the 110′ 2″ level. This flooded state is assumed to last for 30 days.

Table 3D.5-4

ABNORMAL OPERATING ENVIRONMENTS OUTSIDE CONTAINMENT

Conditions/Parameter	Abnormal Extreme	Duration	Notes
Zones 1, 4, 5, 6, 7, 8, 9, 10	Same as normal		
Zone 2 - Loss of HVAC - (I&C Rooms, DC Equipment Rooms)			Note 4
Temperature	Figure 3D.5-1 (Sheets 2, 3)	7 days	Note 3
Pressure	Atmospheric		
Humidity	65 - 95%		Note 2
Radiation	Same as normal		
Chemistry	None		
Submergence	None		
Zone 3 - Loss of HVAC - (Main Control Room)			
Temperature	Figure 3D.5-1 (Sheet 1)	7 days	
Pressure	Atmospheric		Note 1
Humidity	65 - 95%		Note 2
Radiation	Same as normal		
Chemistry	None		
Submergence	None		
Zone 11 - Loss of AC Power - (Fuel Handling Area)			
Temperature	212°F maximum		
Pressure	Atmospheric		Note 5
Humidity	100%		
Chemistry	None		
Duration	2 weeks		

Notes:

1. Main control room air pressure is maintained above a nominal value of atmospheric during accident conditions to prevent radioactive contaminant entry.
2. Initially, relative humidity is taken to be 65 percent, with gradual increase to a maximum value of 95 percent at 72 hours.
3. Test environments resulting from rooms with equipment supplied by 24- and 72-hour batteries are shown on Sheet 2 for the DC equipment rooms 12203 and 12207 and Sheet 3 for the I&C rooms 12302 and 12304. The 24-hour battery is disconnected at 24 hours. The 72-hour battery is not disconnected. Environments resulting from rooms with equipment supplied by 24-hour batteries only, i.e., DC equipment rooms 12201 and 12205 and I&C rooms 12301 and 12305 are enveloped by the environments shown on Sheets 2 and 3.
4. Abnormal environments in other rooms within Zone 2 are the same as normal.
5. A relief panel is designed to open when the fuel handling area temperature exceeds 165°F.

Table 3D.5-5

ACCIDENT ENVIRONMENTS

(See Table 3D.5-1 for environmental zones)

Zone 1 - Inside Containment	
Temperature, pressure and relative humidity	See Figures 3D.5-6 and 3D.5-7
Radiation	See Figures 3D.5-2 through 3D.5-5
Zones 2, 3, 4, 6, 7, 8, 9, 11	
(Same as abnormal - see Table 3D.5-4)	
Zones 5 and 10 - Outside Containment	
MSIV Compartments	
Temperature, pressure and relative humidity	See Figure 3D.5-8
Radiation	See Figures 3D.5-4 and 3D.5-5

Table 3D.6-1

MECHANICAL EQUIPMENT COMPONENTS REQUIRING ENVIRONMENTAL QUALIFICATION

Component	Material Property
Gaskets	Compression set/elongation
O-rings	Compression set/elongation
Diaphragms	Elongation/tensile strength
Diaphragm support sheets	Tensile strength/elongation
Lubricant	Viscosity/penetration
Worm gear	Flexural strength

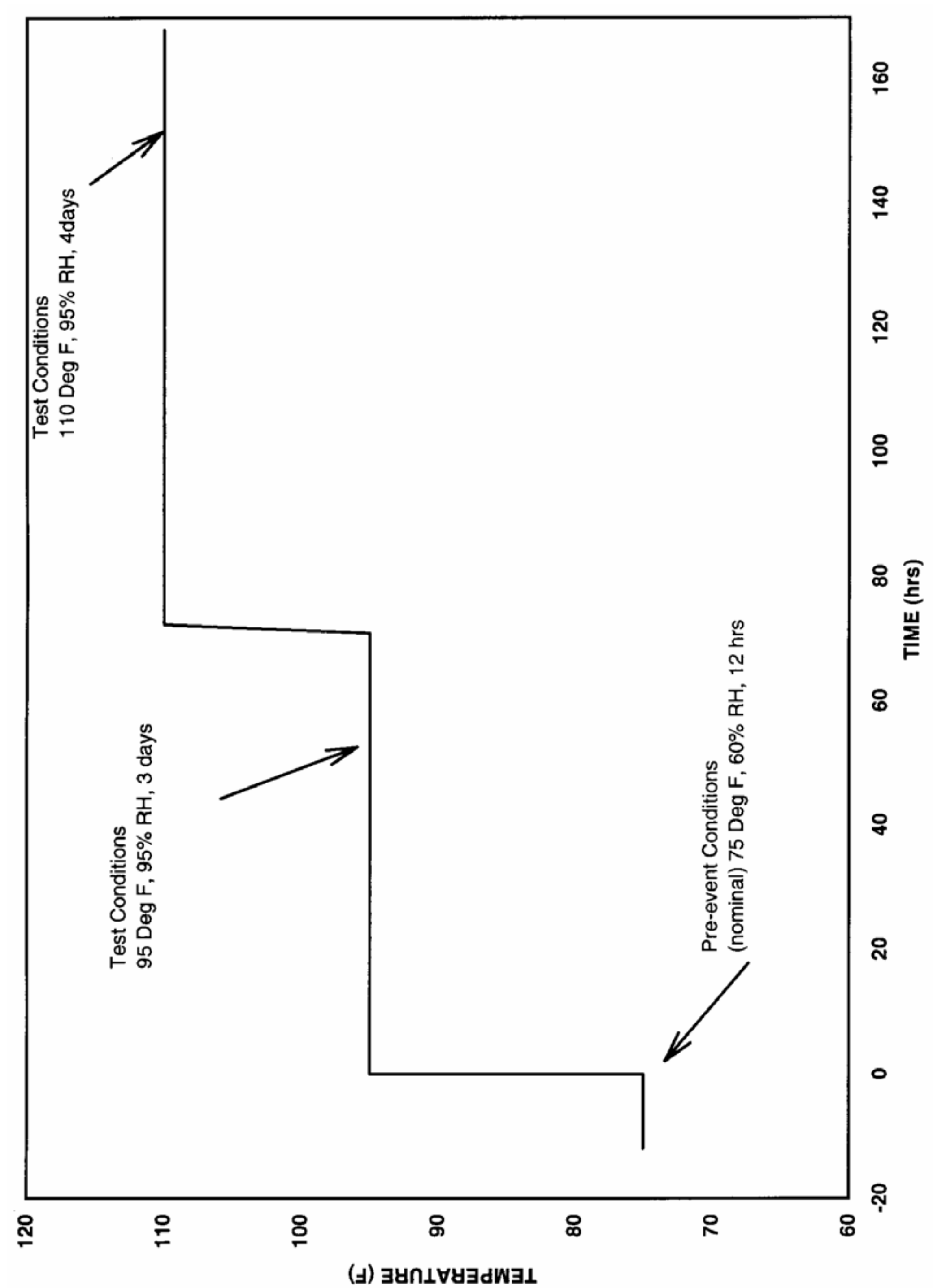


Figure 3D.5-1 (Sheet 1 of 4)

**Typical Abnormal Environmental Test Profile:
Main Control Room**

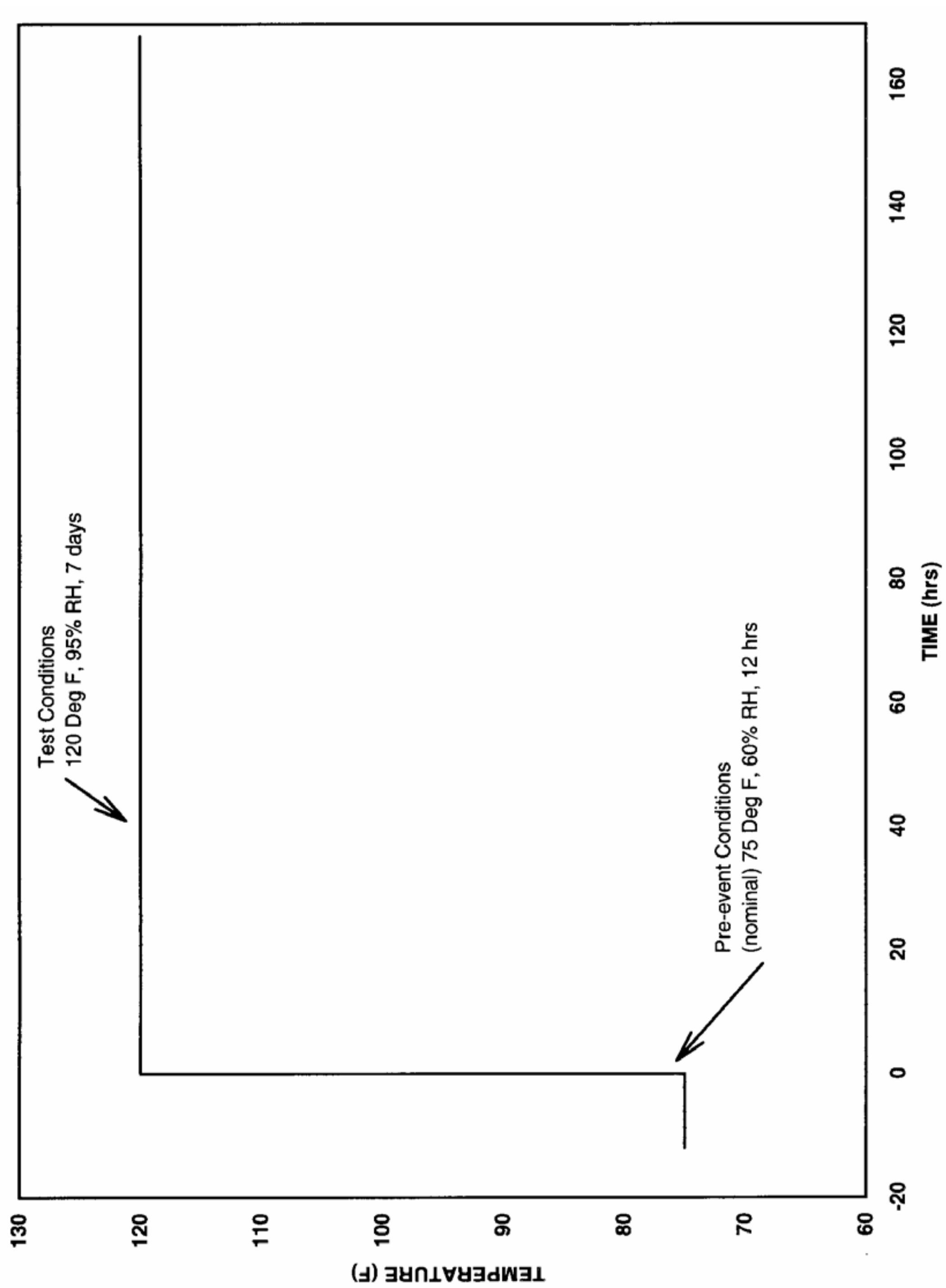


Figure 3D.5-1 (Sheet 2 of 4)

Typical Abnormal Environmental Test Profile: DC Equipment Rooms 12203 and 12207

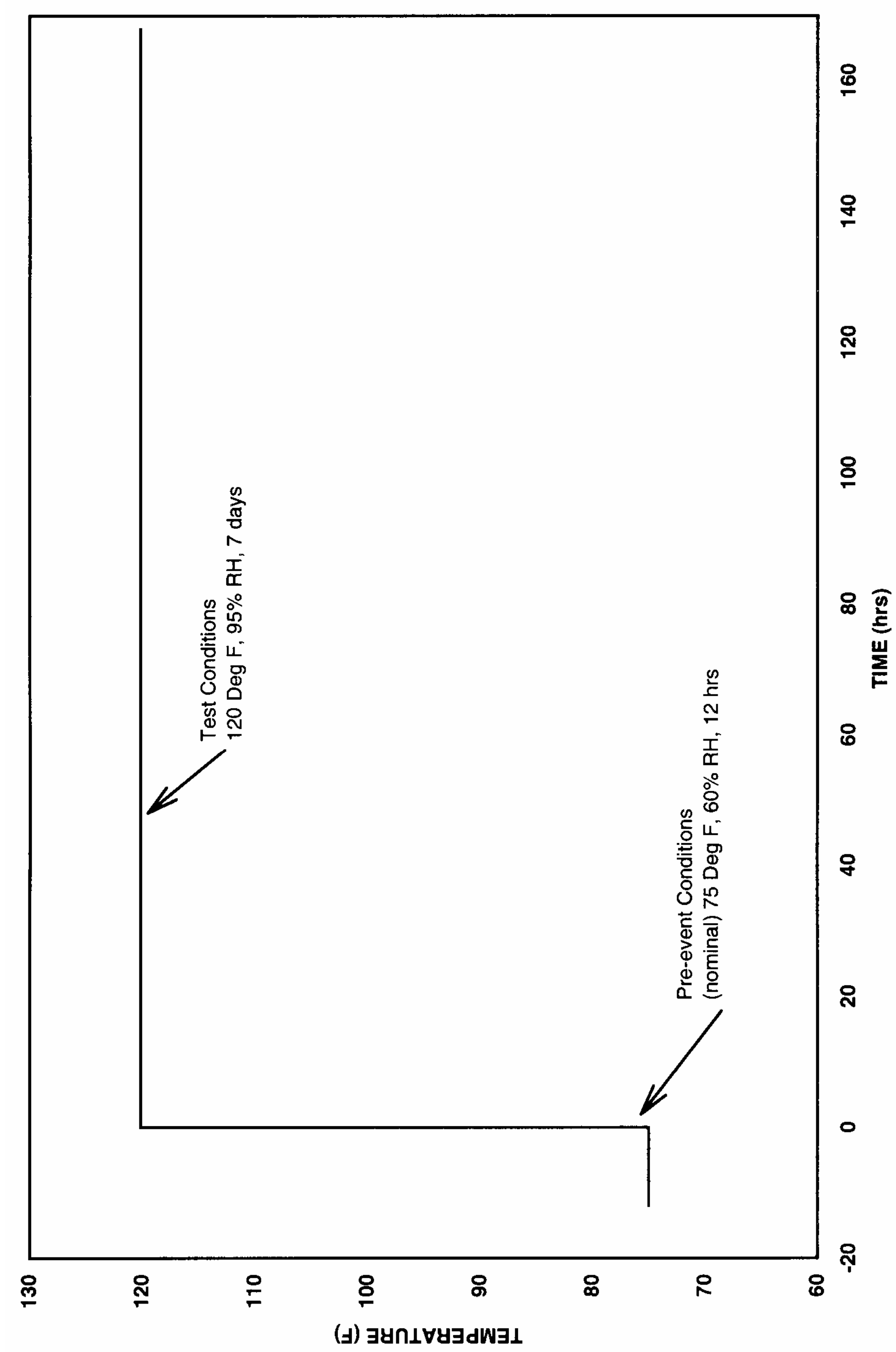


Figure 3D.5-1 (Sheet 3 of 4)

Typical Abnormal Environmental Test Profile:
I&C Rooms 12302 and 12304

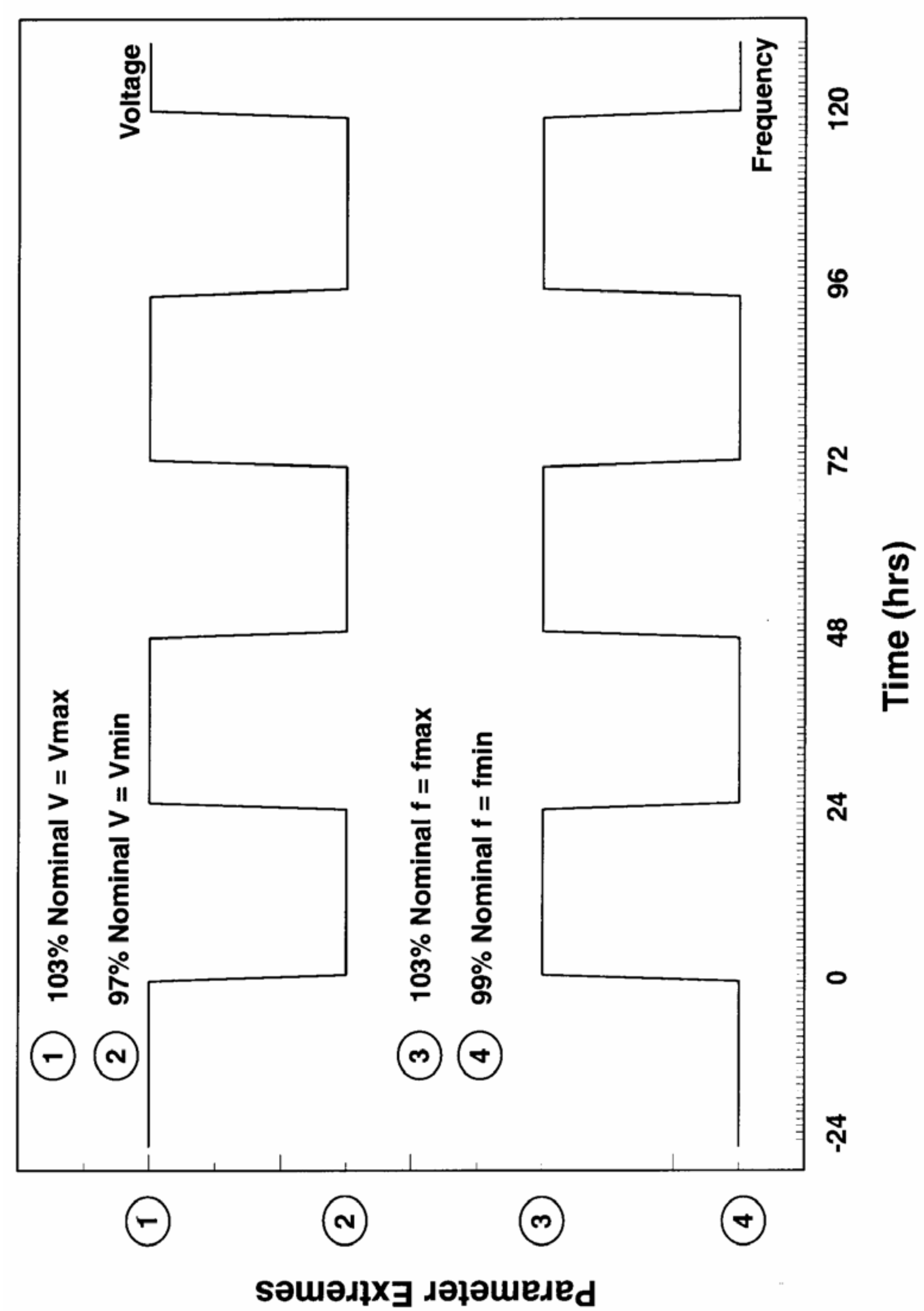


Figure 3D.5-1 (Sheet 4 of 4)

**Typical Abnormal Environmental Test Profile:
Voltage and Frequency Variations**

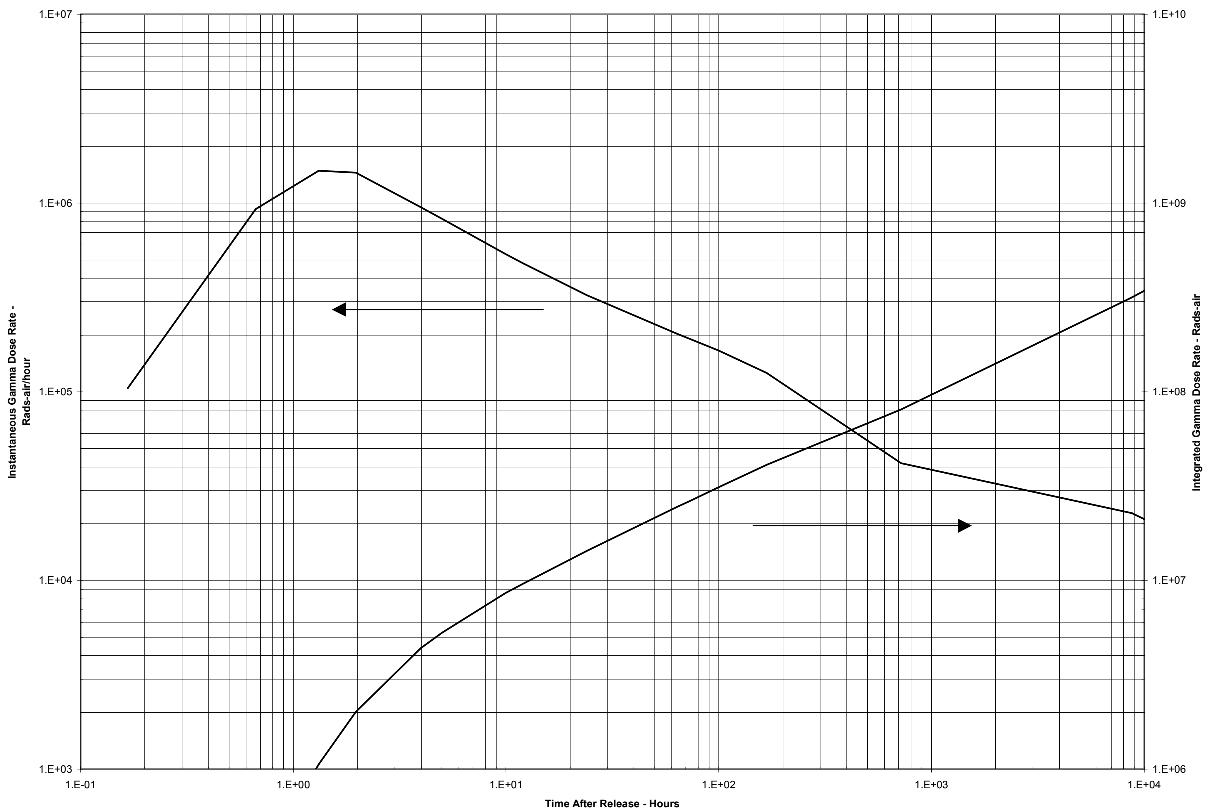


Figure 3D.5-2

Gamma Dose and Dose Rate Inside Containment After a LOCA

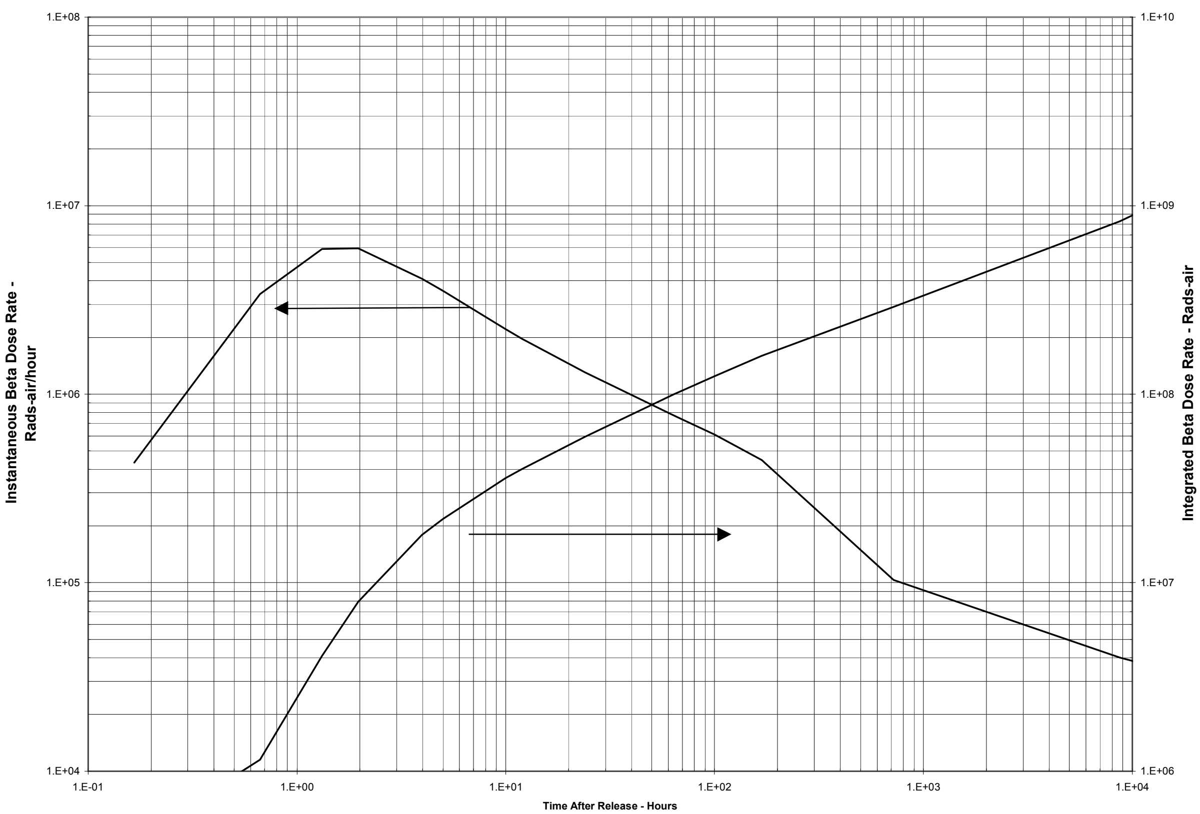


Figure 3D.5-3

Beta Dose and Dose Rate Inside Containment After a LOCA

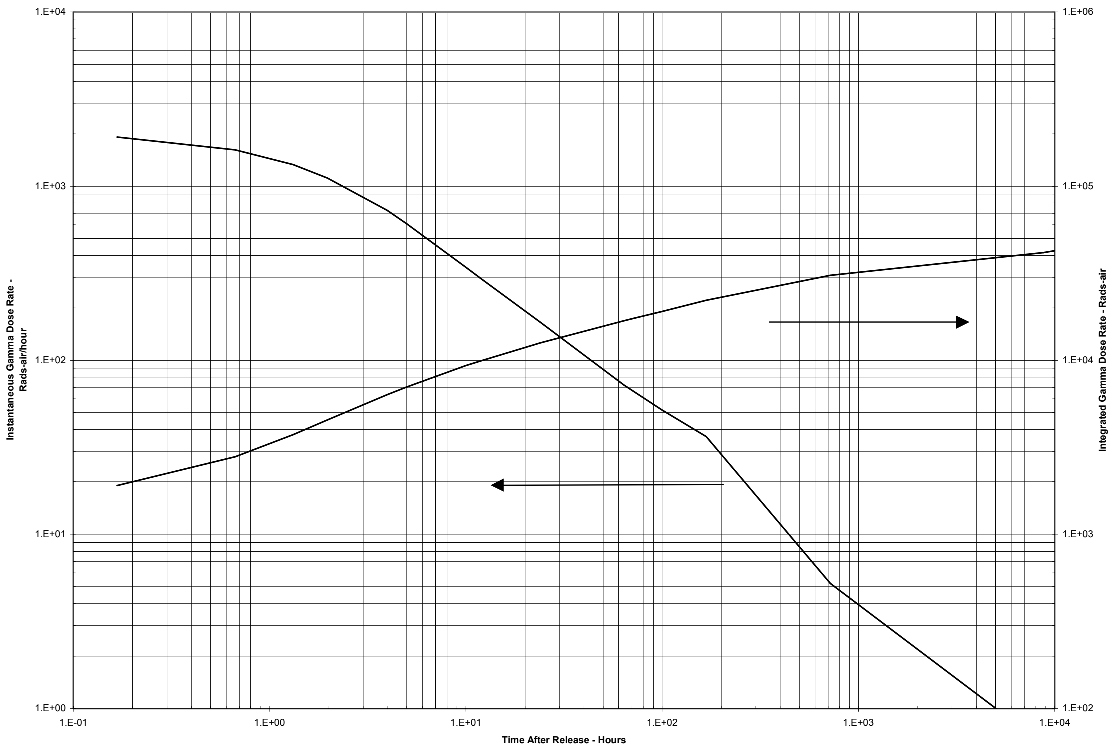


Figure 3D.5-4

Gamma Dose and Dose Rate Inside Containment After a Steam Line Break

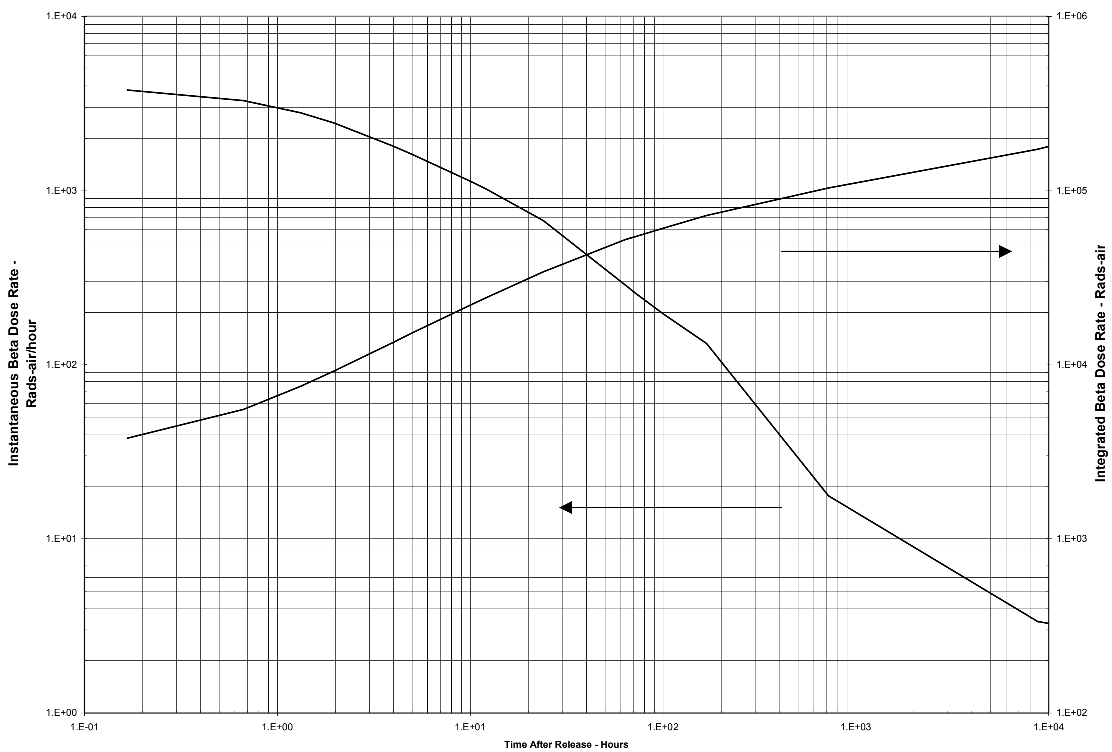


Figure 3D.5-5

Beta Dose and Dose Rate Inside Containment After a Steam Line Break

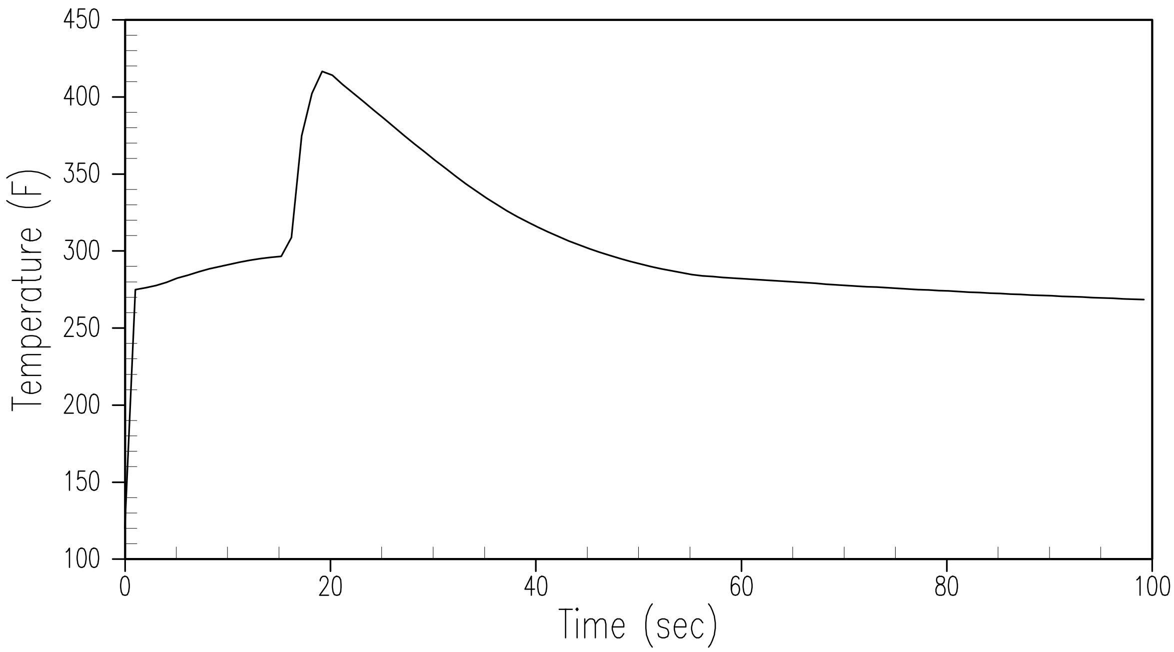


Figure 3D.5-6 (Sheet 1 of 2)

Containment Temperature Design Conditions: LOCA

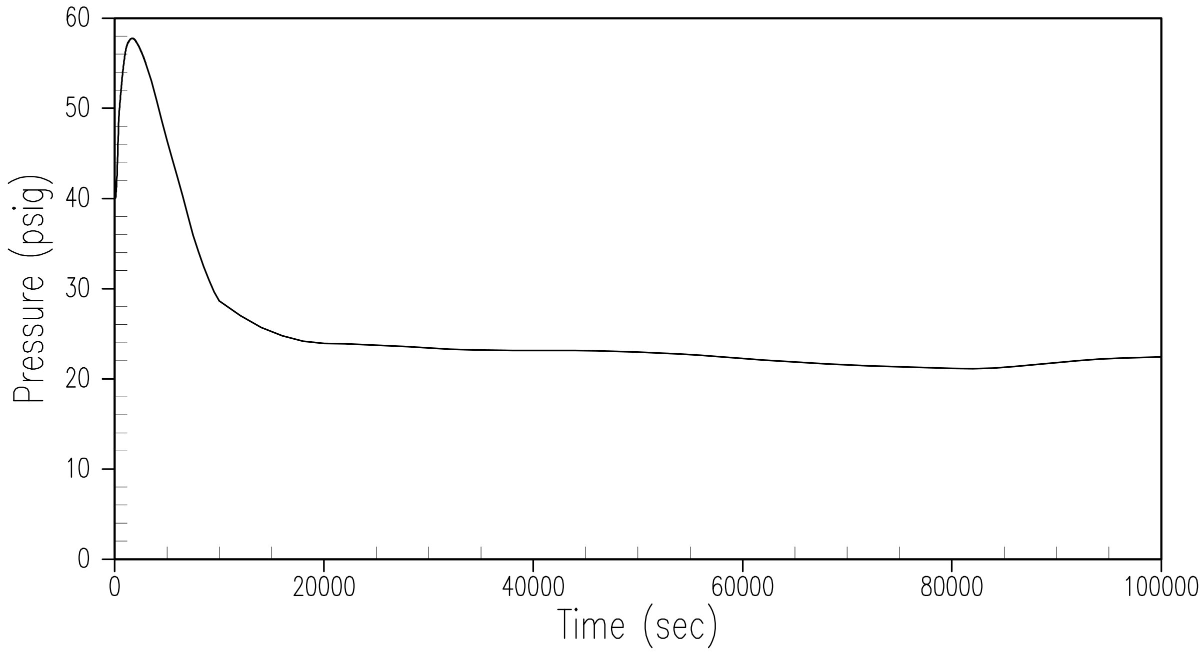


Figure 3D.5-6 (Sheet 2 of 2)

Containment Pressure Design Conditions: LOCA

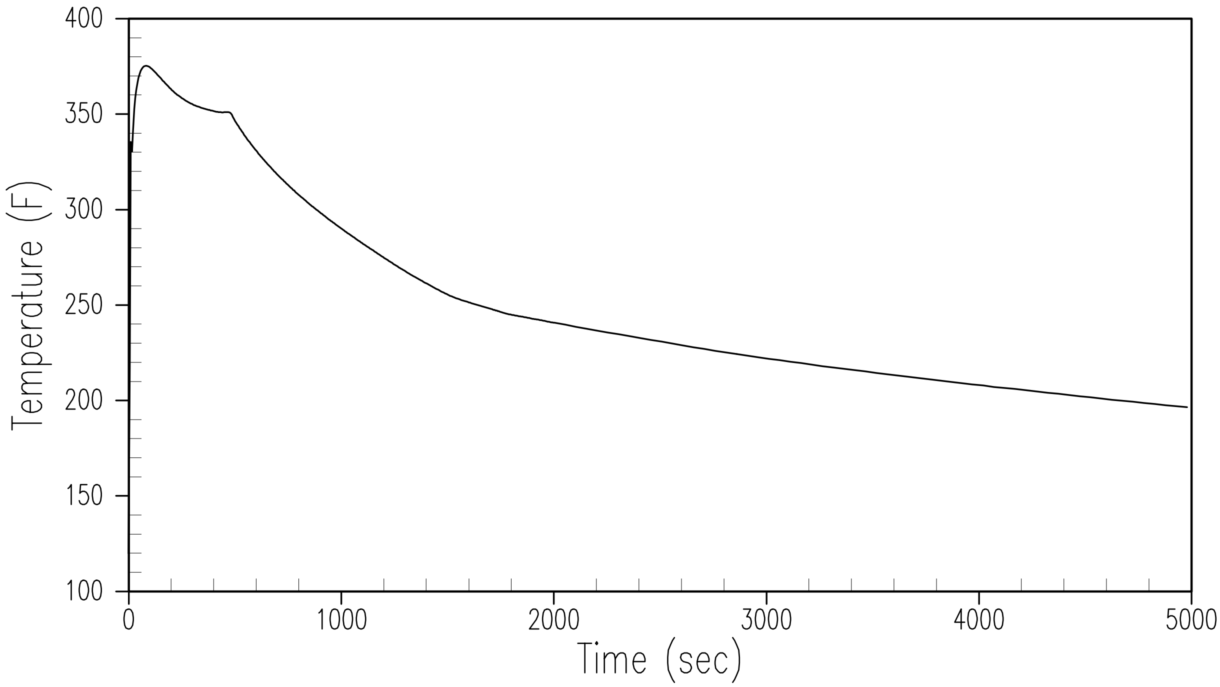


Figure 3D.5-7 (Sheet 1 of 2)

Containment Temperature Design Conditions: MSLB

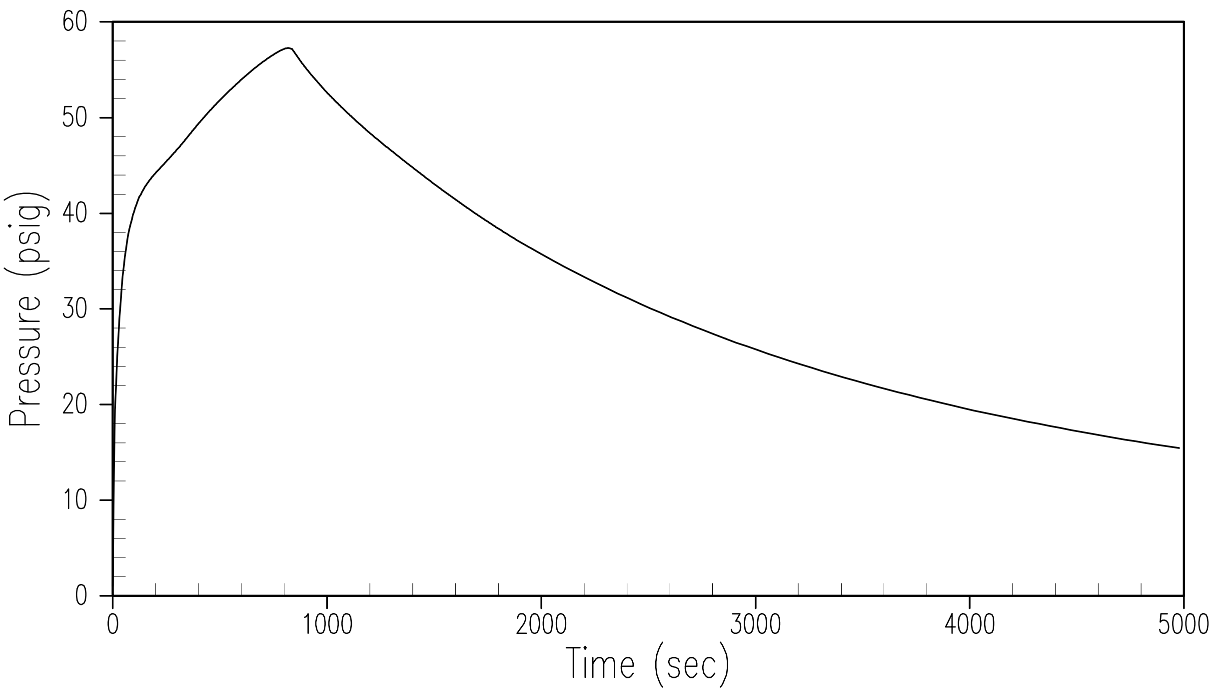


Figure 3D.5-7 (Sheet 2 of 2)

Containment Pressure Design Conditions: MSLB

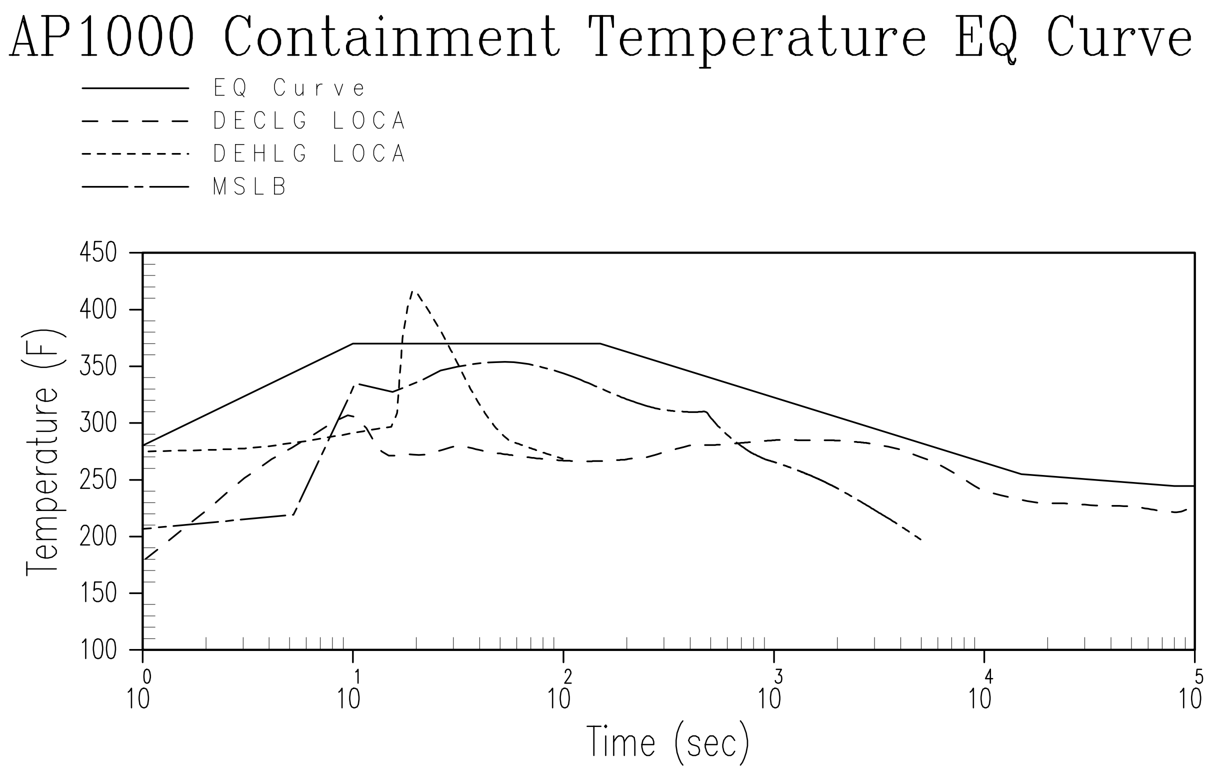


Figure 3D.5-8 (Sheet 1 of 2)

Typical Combined LOCA/SLB/FLB
Inside Containment Temperature Test Envelope

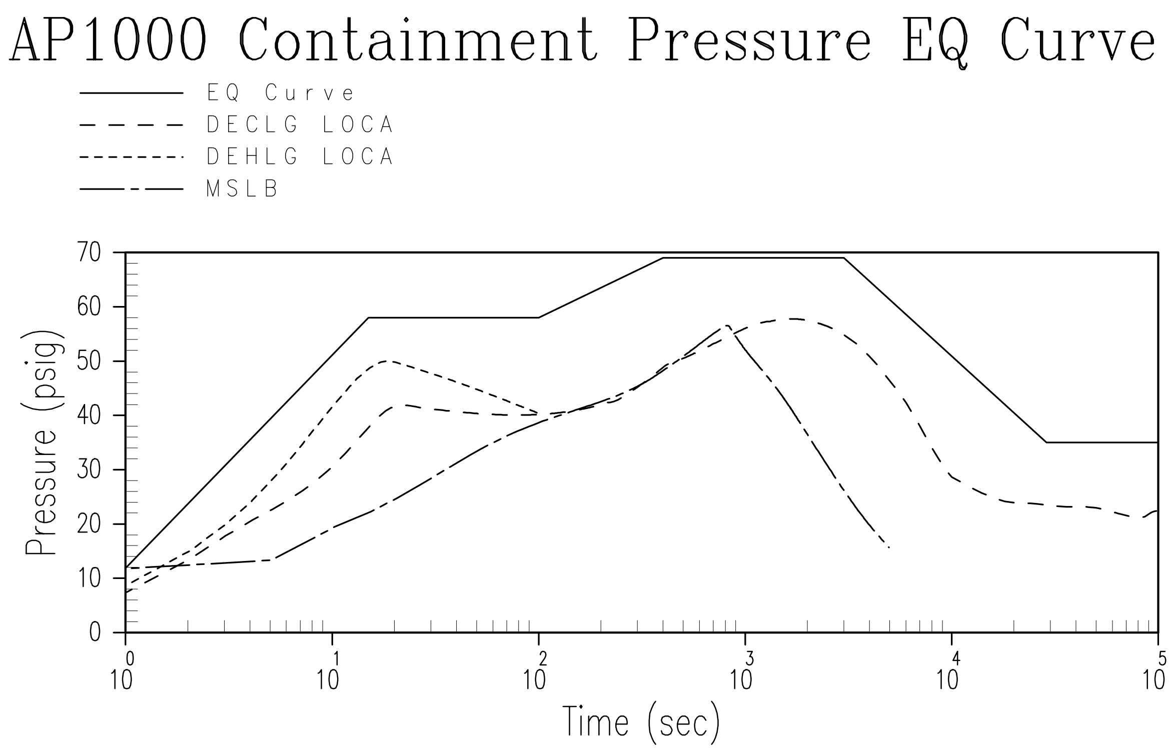


Figure 3D.5-8 (Sheet 2 of 2)

**Typical Combined LOCA/SLB/FLB
Inside Containment Pressure Test Envelope**

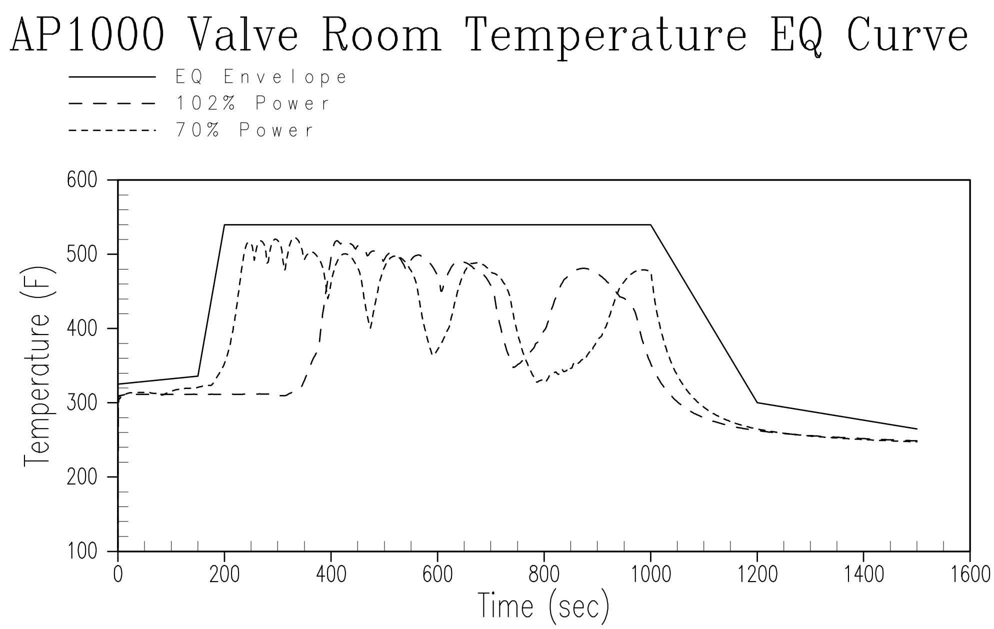


Figure 3D.5-9

Outside Containment Temperature Test Envelope

ATTACHMENT A

SAMPLE EQUIPMENT QUALIFICATION DATA PACKAGE (EQDP)

The equipment qualification data package consists of the following elements:

Section 1.0–Specifications
Section 2.0–Qualification Program
Section 3.0–Qualification by Test
Section 4.0–Qualification by Analysis
Section 5.0–Qualification by Experience
Section 6.0–Qualification Program Conclusions
Table 1–Qualification Summary

EQDP-_______
Rev. _______
{date issued}

EQUIPMENT QUALIFICATION DATA PACKAGE

Equipment	________________________________
Manufacturer	________________________________
Model	________________________________
Application	________________________________
Environment:	____ Harsh ____ Mild
Prepared by:	________________________________ {name}
Reviewed by:	________________________________ {name}
Approved by:	________________________________ {name}

This document provides or summarizes the seismic and environmental qualification of the equipment identified above in accordance with the AP1000 EQ Program Methodology.

1.0 SPECIFICATIONS

1.1 EQUIPMENT IDENTIFICATION: {create table(s) for details if a model series is to be qualified.}

Manufacturer	___________________________________
Model	___________________________________
Technical Manual	___________________________________
Drawings	___________________________________
Specification No.	___________________________________
Modifications	___________________________________

1.2 INSTALLATION REQUIREMENTS: {Cite vendor technical manual; details of mounting used for seismic test specimen(s); include any special requirements unique to Class 1E service}

1.3 ELECTRICAL REQUIREMENTS

1.3.1	Voltage:	__________	
1.3.2	Frequency:	__________	{if powered by AC}
1.3.3	Load:	__________	{as applicable}
1.3.4	Other:	__________	{identify and address as needed}

1.4 AUXILIARY DEVICES: {These are devices required to be interfaced with the subject equipment to provide qualification or operability but not specifically included or addressed in this document.}

1.5 PREVENTATIVE MAINTENANCE: {Identify manufacturer recommended maintenance activities required as part of the qualification program. Identify activities that are required to support qualification or the qualified life. "None" shall mean that maintenance is not essential to qualification or the qualified life. The following statement may be used in cases where qualification is not contingent upon maintenance or surveillance activities:

"No preventive maintenance is required to support the equipment qualified life. This does not preclude development of a preventive maintenance program designed to enhance equipment performance and identify unanticipated equipment degradation as long as this program does not compromise the qualification status of the equipment. Surveillance activities may also be considered to support the basis for, and a possible extension, of the qualified life."}

1.6 SAFETY FUNCTIONS

{Specify known safety functions for which qualification is intended to apply.}

1.7 PERFORMANCE REQUIREMENTS[a] for: {RCS Loop RTDs}

	Parameter	Normal Conditions	Abnormal Conditions	Containment Test Abnormal	DBE[b] Conditions Seismic	DBE[b] Conditions LOCA
1.7.1	Time requirement					
1.7.2	Performance					

1.8 ENVIRONMENTAL CONDITIONS[a] for Same Function

1.8.1	Temperature (°F)					
1.8.2	Pressure (psig)					
1.8.3	Humidity (%RH)					
1.8.4	Radiation (Rads)					

1.8.5 Chemicals

1.8.6 Vibration

1.8.7 Acceleration (g)

Notes: a: Test margin is not included in the parameters of this section.
b: DBE is the Design Basis Event.

{If more than one set of performance requirements and/or associated environmental conditions are to be specified, replicate these sections in pairs as "1.8 Performance ..." and "1.9 Environment ...", etc.}

2.0 QUALIFICATION PROGRAM

2.1 PROGRAM OBJECTIVE

The objective of this qualification program is to demonstrate, employing the recommended practices of Regulatory Guides 1.89 and 1.100 and IEEE 323-1974, 344-1987, {cite others as applicable} capability of the {Equipment description} to perform its/their safety related function(s) described in EQDP Section 1.7 while exposed to the applicable conditions and events defined in EQDP Section 1.8.

{Narrative should introduce an outline of the program plan. Table below to be completed as graphic reference. Table shall not be abbreviated; items must appear and be addressed by direct response.}

2.2 REFERENCES

{List test report(s) and information sources cited in this document}

	Qualification Method(s)		
CONDITION	**TEST**	**ANALYSIS**	**OTHER**
Aging:			
Thermal	________	________	________
Radiation	________	________	________
Vibrational	________	________	________
Operational Cycling	________	________	________
Electrical	________	________	________
Mechanical	________	________	________
Abnormal Environment	________	________	________
Inadvertent ADS Actuation	________	________	________
Seismic	________	________	________
LOCA	________	________	________
HELB Inside Containment	________	________	________
HELB Outside Containment	________	________	________
Post-accident Aging	________	________	________

NOTES:

{All spaces above to be noted as "Yes", "No", or "Note #". Notes will be appended to the table. Notes will also include items "Not Applicable" with terse explanation and/or forwarding reference.}

3.0 QUALIFICATION BY TEST (TEST PLAN AND SUMMARY)

3.1 SPECIMEN DESCRIPTION

{Identify the item or items to be tested}

3.2 NUMBER TESTED

{If more than one type is to be tested, identify how many of each. Subsequent Sections should clarify specifics for each.}

3.3 MOUNTING

{Identify specific seismic mounting details, referencing applicable drawings, instructions, documents. Note existence of differences from manufacturer recommendations}

3.4 CONNECTIONS

{Identify interfaces, both electrical and mechanical, identify any connectors or sealing assemblies used which are not provided with the equipment, or are not covered by this qualification.

3.5 TEST SEQUENCE PREFERRED

This section identifies the preferred test sequences as specified in IEEE 323-1974.

3.5.1 Inspection of Test Item
3.5.2 Operation (Normal Condition)
3.5.3 Operation (Performance Specifications Extremes: Section 1)
3.5.4 Simulated Aging
3.5.5 Vibration/Seismic
3.5.6 Operation (Simulated High Energy Line Break Conditions)
3.5.7 Operation (Simulated Post-HELB Conditions)
3.5.8 Inspection

3.6 TEST SEQUENCE ACTUAL

This section identifies the actual test sequence which constitutes the qualification program for this equipment. A justification for anything other than the preferred sequence is provided.

Test Sequence (from Section 3.5):

{List and explain; provide forwarding references to subsequent subsections as necessary}

3.7 **SERVICE CONDITIONS TO BE SIMULATED BY TEST**[1]

	Normal	Abnormal	Seismic	HELB	Post-HELB
3.7.1 Temperature (°F)					
3.7.2 Pressure (psig)					
3.7.3 Humidity (% RH)					
3.7.4 Radiation (Rads)					
3.7.5 Chemicals					
3.7.6 Vibration					
3.7.7 Seismic (g)					

(1) Test parameter margins are included for the worst-case known requirements applicable to the equipment type. Margin for a specific parameter is dependent on the requirements of each application or location for the equipment; these may vary.

(2) Post-accident operability addressed through simulated thermal aging. Temperature and other parameters are selected to envelop the requirements.

3.8 MEASURED VARIABLES

This section tabulates the variables and parameters required to be measured during each of the following tests in the qualification test sequence.

Tests: {example}
A: Thermal Aging
B: Mechanical Cycling
C: Irradiation
D: Seismic Test
E: HELB Test

	Required	Not Required
3.8.1 Category I – Environment		
3.8.1.1 Temperature	...	...
3.8.1.2 Pressure	...	...
3.8.1.3 Moisture	...	...
3.8.1.4 Gas Composition	...	...
3.8.1.5 Vibration	...	...
3.8.1.6 Time	...	...
3.8.2 Category II – Input Electrical Characteristics		
3.8.2.1 Voltage	...	...
3.8.2.2 Current	...	...
3.8.2.3 Frequency	...	...
3.8.2.4 Power	...	...
3.8.2.5 Other	...	...
3.8.3 Category III – Fluid Characteristics		
3.8.3.1 Chemical Composition	...	...
3.8.3.2 Flow Rate	...	...
3.8.3.3 Spray	...	...
3.8.3.4 Temperature	...	...
3.8.4 Category IV – Radiological Features		
3.8.4.1 Energy Type	...	...
3.8.4.2 Energy Level	...	...
3.8.4.3 Dose Rate	...	...
3.8.4.4 Integrated Dose	...	...
3.8.5 Category V – Electrical Characteristics		
3.8.5.1 Insulation Resistance	...	...
3.8.5.2 Output Voltage	...	...
3.8.5.3 Output Current	...	...
3.8.5.4 Output Power	...	...
3.8.5.5 Response Time	...	...
3.8.5.6 Frequency Characteristics	...	...
3.8.5.7 Simulated Load	...	...

	Required	Not Required
3.8.6 Category VI – Mechanical Characteristics		
3.8.6.1 Thrust	...	...
3.8.6.2 Torque	...	...
3.8.6.3 Time	...	...
3.8.6.4 Load Profile	...	...
3.8.7 Category VII – Auxiliary Equipment		
3.8.7.1 {as applicable, also see Section 1.4 of EQDP}	...	...

3.9 TYPE TEST SUMMARY

3.9.1 Normal Environment Testing

Operation of the {equipment} under normal conditions is demonstrated by {discuss test, checks, et. al. which provide baseline performance data} ... , as reported in Reference _.

3.9.2 Abnormal Environment Testing

Operation of the {equipment} under abnormal conditions is demonstrated by {discuss test, checks, et. al. which provide baseline performance data} ... , as reported in Reference _.

3.9.3 Aging Simulation Procedure

{Describe the aging mechanisms simulated and the sequence, including justifications as necessary.}

The test units were pre-conditioned to simulate an aged condition prior to subjecting them to the Design Basis Event (DBE) seismic and environmental conditions/simulation. The aged condition was achieved by separate phases of {accelerated thermal aging, thermal cycling, and radiation exposure to a total integrated gamma dose equivalent to a twenty-year normal dose plus the design basis accident dose, and accelerated flow induced and pipe vibration simulation}. Through all the pre-conditioning phases, the {equipment, performance} were monitored to verify {continuous operation}.

3.9.3.1 Design Life: {Also, justification of the bases for a design life goal should be provided, when used in mild-environment programs. Generally inapplicable to harsh-environment programs.}

3.9.3.2 Shelf Life: {Though not typically applicable, state any limitation in life, as well as conditions which may be detrimental if known.}

3.9.3.3 Thermal Aging: The qualified life is __ years based on an ambient temperature of {__°C (__°F) and a __°C temperature rise due to _______}. Calculations are based on a test temperature of __, test duration of ___ hours, and an activation of ___ eV (See References x, et al.)}.

3.9.3.4 Radiation Aging: The qualified life is limited by the expected radiation during the __-year life and the Design Basis Event. {Subtract accident TID from qualified TID; account for margin, remainder is to be compared to normal/abnormal radiation requirements to yield life limits.}

3.9.3.5 Operating Cycles: {Expected number of electrical and/or mechanical cycles, or numbers of actuations, as applicable. Estimated on the basis of the expected for the design, qualified, installed life of the equipment. Specification may be on a per annum or a per fuel cycle basis. Compare to cycle life data from test.}

3.9.3.6 Vibration Aging: {present bases; refer to test profile and/or Subsection 3.9.4}.

3.9.4 Seismic Tests

The seismic testing reported in Reference x was completed on aged equipment employing {method(s)} in accordance with Regulatory Guide 1.100 and IEEE 344-1987. ... {Summarize equipment condition and/or performance versus the acceptance criteria.} ... Actual margin should be determined for each application/location throughout the plant and verified to meet or exceed the margin requirements.

{Discuss or reference discussion of test anomalies.}

3.9.5 High Energy Line Break/Post HELB Simulation

The {equipment} were subjected to the HELB simulation temperature/pressure profile of Figure x. Following the __°F temperature peak, the temperature gradually declines to __°F and is held at saturated steam conditions for _ days, simulating a _____ period of Post-HELB operation. The test data and activation energy specified in Subsection 3.9.3.3 can be used to determine margin in post-accident aging for each application/location of the equipment.

{Summarize equipment condition and/or performance versus the criteria}

{Discuss or reference discussion of test anomalies.}

4.0 QUALIFICATION BY ANALYSIS

The AP1000 EQ Program does permit qualification solely on the basis of analyses for equipment outside the scope of 10CFR50.49. The following subsections discuss each of the analyses preformed, its test basis and justification, and summarizes conclusions documented in References x; et. al., which provided detailed accounts of each analysis.

{Each subsection will address a particular analysis, if more than one is performed to support qualification.}

4.x (EXAMPLE)

{The purpose and objective will be identified here. Subsections will provide necessary details per the following format.}

4.x.1 {Equipment, Characteristic or Aspect} Analyzed

{A general description of the equipment and its function based on applicable equipment and mounting drawings, and purchase orders.}

4.x.2 Equipment Specification(s)

{The applicable design standards shall be documented including any limitations imposed by the equipment specification. Installation detail considered or represented are to be included.}

4.x.3 Methods and Codes

{Description of analytical methods or techniques, computer program, mathematical model(s) used, and the method(s) of verification}

4.x.4 Acceptance Criteria

{The specific safety function(s), postulated failure modes, or the failure effects to be demonstrated by analysis.}

4.x.5 Model

{Description of mathematical model of equipment or feature analyzed.}

4.x.6 Assumptions and Justifications

{EXAMPLES: Description of the loading conditions to be used. Summary of stresses to be considered.}

4.x.7 Impact to Safety Function

{Summarize analytically established performance characteristics and their acceptability. Discussion and summary of the analytical results which demonstrate equipment structural integrity and, where appropriate, operability. Particular to cabinets, critical deflections should be determined and included in mounting requirements for spacing with respect to other equipment and structures.}

4.x.8 Conclusions

{Descriptive summary, including any conditions imposed on qualification or use; qualified life, limitations, surveillance/maintenance requirements, et. al.} Further discussion of this analysis is presented in Reference x.

4.Y ENVIRONMENTAL QUALIFICATION ANALYSIS FOR {VALVE SOFT PARTS}

{purpose and objective}

4.Y.1 Equipment Identification

{Per Subsection 6.2.3.1}

4.Y.2 Component Identification

{Per Subsection 6.2.3.1}

4.Y.3 Safety Related Functions

{Per Subsection 6.2.3.2}

4.Y.4 Component Acceptance Criteria

{Per Subsection 6.2.3.3}

4.Y.5 Service Conditions

{Per Subsection 6.2.3.4}

4.Y.6 Potential Failure Modes

{Per Subsection 6.2.3.5}

4.Y.7 Identify the Environmental Effects on Material Properties

Each non-metallic, including lubricants, is evaluated to determine the effect of the environmental conditions on the material properties. For each non-metallic, a radiation threshold level and maximum service temperature is identified.

The radiation threshold level and the maximum service temperature are identified using materials handbooks, textbooks, government and industry reports, and laboratory data. If the evaluation indicates that the lowest levels may be exceeded for certain equipment, higher levels are identified at which varying degrees of material degradation may occur.

Mechanical equipment is highly resistive to degradation due to elevated humidity levels: therefore, relative humidity is not included as a parameter to be evaluated for environmental qualification. Pressure can be discounted for most equipment types, as there are no foreseen failures due to elevated pressure levels for most mechanical equipment. However, pressure must be addressed in the evaluation.

The susceptibility of the non-metallic material to the chemicals due to the design basis accident and exposure to the process fluid is evaluated. The material information in the chemical handbooks is an acceptable source of qualification documentation.

4.Y.7.1 Perform Thermal Aging Analysis

Aging analysis is performed for organic materials. Mineral-based subcomponents are not considered to be sensitive to thermal aging during the design life of a plant and, therefore, are not analyzed.

Aging in mechanical components is associated with corrosion, erosion, particle deposits and embrittlement. In new construction, corrosion and erosion are considered by providing additional material thickness as a corrosion or erosion allowance above the required design. The other aging phenomena are considered during inservice inspections of operating components as contained in plant technical specifications and ASME Code, Section XI. Aging qualification of metallic parts of equipment except for corrosion and erosion is in compliance with ASME Code, Section XI, therefore aging effects on metallic components are not addressed herein.

The non-metallic material analysis for determining the expected qualified thermal life is performed using Arrhenius methodology. The thermal input during the operating time, as explained below, is deducted from the tested thermal aging of the material at service temperature to obtain the qualified life.

The component is evaluated for the specified post-accident operating time. The thermal input from the postulated accident profile (i.e., LOCA/MSLB) for the duration of the specified operating time is compared to the material thermal aging data. The Arrhenius model is used to perform this comparison. The component is evaluated for the maximum post-accident operating time unless a system analysis is performed to justify shorter operating times.

Analysis of the non-metallics should also take into account any degradation of the part due to its use in dynamic modes (i.e., moving part).

4.Y.7.2 Evaluate the Environmental Effects on Equipment Safety-Related Function

A conservative initial screening of the non-metallic subcomponents is made by comparison of the material capabilities (threshold radiation level and maximum service temperature) with the maximum postulated environmental conditions. If the threshold radiation values and the maximum service temperatures are above the maximum postulated environmental conditions, and if the material aging analysis demonstrates a service life sufficient to survive the accident duration, then the material is considered acceptable.

Those items which are not shown to be acceptable based on the above comparison are evaluated in further detail regarding:

- extent of material degradation
- material properties affected
- equipment/subcomponent function
- extent of equipment functional degradation
- location-specific environmental conditions

4.Y.8 Conclusions

{Per subsection 3D.6.2.3.7}

4.Y.9 EQ Maintenance Requirements

{Per subsection 3D.6.2.3.8}

5.0 QUALIFICATION BY EXPERIENCE

The AP1000 EQ Program does not typically permit qualification solely on the basis of operating experience in support of the qualification program for the {equipment}. For those instances where seismic experience data are to be used, the COL will provide documentation of the methodology. Operating experience is used for or to supplement the qualification of {equipment} with respect to the following conditions {list with justification}.

6.0 QUALIFICATION PROGRAM CONCLUSIONS

6.1 AGING

{Discuss specifics and state on limitations or requirements; specifics with respect to:

- Design Life Goal
- Thermal Aging
- Radiation Aging
- Operating Cycles
- Vibration Aging}

6.2 DBE QUALIFICATIONS

6.3 PROGRAM CONCLUSIONS

The qualification of the {equipment} is demonstrated by the completion of the simulated aging and Design Basis Event testing described herein and reported in Reference {1}.

{State any conditions imposed on qualification or qualified life, cite any lessons learned which necessitate future user actions to preserve continued qualification}

{Refer to Table 1}

Table 1

QUALIFICATION SUMMARY

SYSTEM	{RPS}
CATEGORY	Category(1) {a}
LOCATION	{Containment bldg.}
STRUCTURE/AREA	{Zone Number}
EQUIPMENT TYPE	{pressure transmitter }
MANUFACTURER	{____________}
MODEL	{____________}

PARAMETER	QUAL METHOD(2)	ENVIRONMENTAL EXTREMES QUALIFIED(3)	ENVIRONMENTAL EXTREMES SPECIFIED(4)	NOTES
NORMAL				
ABNORMAL				
QUALIFIED LIFE				{5}
SEISMIC	{Both}	Figure x	{Ref; Fig.}	
ACCIDENT		Figure x	{Ref; Fig.}	
Temperature	{Test}	____°F		
Pressure	{Test}	____ psig		
Rel. humidity	{Test}	____%		
Radiation	{Both}	____E+06 R(γ)		
	{Both}	____E+06 R(β)		
Chemistry	{Test}	{Note 6}		
Operability	{Both}			
Accuracy	{Test}			

NOTES:

1. Equipment category as per NUREG-0588, Appendix E, Section 2.
2. Qual. Methods are: Test, Analysis, Both (Test & Anal.), or Other.
3. Qualified values are test extremes which include margin.
4. Environmental parameters for the plant location are to be inserted. If more than one applicable, most extreme are to be cited
5. Qualified life estimated on basis of maximum normal temperature of ____°C (__°F) and a temperature rise of ____°C (____°F).
6. Chemistry Conditions: {pH and composition}.

ATTACHMENT B

AGING EVALUATION PROGRAM

B.1 Introduction

As stated in IEEE 323, aging of Class 1E equipment during normal service is considered as an integral part of the qualification program. The objective is not to address random age-induced failures that occur in-service and are detected by periodic testing and maintenance programs. The objective is to address the concern that some aging mechanisms, when considered in conjunction with the specified design basis events (DBE), may have the potential for common mode failure.

The AP1000 equipment qualification program addresses the aging concern and makes maximum use of available data and experience on aging mechanisms. This approach places primary emphasis on common mode failures due to enveloping design basis events. For example, reasonable assurance against common mode failures being induced because of a loss of heating, ventilation, and air conditioning (HVAC) is provided by adequate design, normal maintenance, and calibration procedures.

B.2 Objectives

The objectives of the aging evaluation program follow:

- To establish, where possible, the effects of the degradation due to aging mechanisms that occur before the occurrence of an accident, when safety-related equipment is called upon to function

- To provide increased confidence that safety-related equipment performs its safety-related function under the specified service condition.

B.3 Basic Approach

The general approach to addressing aging allocates equipment to one of two subprograms (A or B).

- Subprogram A includes electrical equipment required to perform a safety-related function in a high-energy line break (HELB) environment. For this equipment an aging simulation is included as part of the equipment qualification test sequence. The equipment is energized during the aging simulation.

- Subprogram B includes equipment required to mitigate high-energy line breaks but which, due to its location, is isolated from any adverse external environment resulting from the accident. For equipment in Subprogram B the single design basis event capable of producing an adverse environment at the equipment location is the seismic event. Aging, for Subprogram B, is not included in the equipment qualification test sequence. Significant aging mechanisms are determined by evaluation of available test data. Generally, this data is from separate programs conducted to demonstrate that aged components continue to meet

manufacturer's performance specifications under applicable seismic design basis event conditions and that seismic testing of unaged equipment is not invalidated by anticipated aging mechanisms.

B.4 Subprogram A

Electrical equipment required to perform a safety-related function in a high-energy line break (such as a loss of coolant accident, feed line break, or steam line break) environment is included in Subprogram A. This subprogram provides for an aging simulation to be included in the equipment's qualification test sequence.

B.4.1 Scope

The typical equipment scope and aging mechanisms applied under Subprogram A are shown in Tables 3D.B-1 and 3D.B-2, respectively. The equipment selected is that Class 1E equipment qualified to operate in a high-energy line break environment. The aging mechanisms discussed next are those to which the equipment may be potentially sensitive in its installed location.

B.4.2 Aging Mechanisms

The aging mechanisms that could potentially affect electrical equipment in Subprogram A are discussed under the following headings:

Time, in conjunction with:

- Operational stresses (current, voltage, operating cycles, Joulean self-heating)
- (External stresses (thermal, vibration, radiation, humidity, seismic).

The aging mechanisms considered potentially significant and to be simulated are identified in Table 3D.B-2 for each item of equipment in Subprogram A. Where applied, the aging mechanisms are simulated as described in the following discussions.

B.4.3 Time

For equipment subject to high-energy line break conditions, the most significant in-service aging mechanisms (that is, radiation and thermal) come into effect during reactor operation. Consequently, it can be assumed that the "aging clock" starts on plant startup.

B.4.4 Operational Stresses

Electrical Cycling

Electrical supplies to safety-related equipment are, in general, highly stable. So aging effects due to supply cycling during service are not anticipated. Where the equipment is anticipated to experience multiple startup and shutdown cycles, the equipment is electrically cycled to simulate the number of anticipated startup and shutdown cycles plus 10 percent.

Mechanical Cycling

Aging effects resulting from anticipated mechanical cycling of the equipment are simulated by applying, as a minimum, the number of cycles estimated to occur during the target qualified life plus 10 percent. Mechanical cycling covers such operations as switching and relay actuation.

Joulean Self-Heating

Where the equipment is not aged in a live condition, the aging effects resulting from Joulean self-heating are recognized by employing the equipment operating temperature as the datum temperature for assessing the accelerated thermal aging parameters to be employed.

B.4.5 External Stresses

Thermal Effects

Thermal effects are considered one of the most significant aging mechanisms to address. The equipment is thermally aged to simulate an end-of-qualified-life condition using the Arrhenius model to establish the appropriate conditioning period at elevated temperature. Where data is not available to establish the model parameters for the materials employed, a verifiably conservative value of 0.5 eV is used for activation energy (Attachment D).

For each piece of equipment an appropriate normal and abnormal operating temperature and an associated time history are determined for inclusion in the Arrhenius model. The equipment temperature is determined by the addition of an appropriate equipment specific ΔT to the external ambient temperature. Attachment D also provides information concerning the determination of appropriate ambient temperatures and time-temperature histories for use in thermal aging evaluation of equipment. Post-accident thermal aging is included by recognizing the higher post-accident ambient temperatures in determining the parameters employed for the post-accident accelerated thermal aging simulation.

In-Service Vibration

The majority of safety-related electrical equipment has a proven history of in-plant service. Thus, it is unlikely that a significant, undetected, failure mechanism exists because of low-level, in-plant vibration. In addition, a simulation of earthquakes smaller than the safe shutdown earthquake (SSE) employed during equipment and component seismic testing give added confidence that this potential aging mechanism is covered (See Attachment E, Section 4.4). For line-mounted equipment, in-service pipe and flow induced vibration may be significant. As a consequence, an additional vibration aging step is included in the aging sequence as indicated for certain items of equipment in Table 3D.B-2. (See Attachment E, Section 5.2.4.)

Radiation

Radiation during normal operation is not considered an aging mechanism for equipment subject to in-service integrated doses less than 10^4 rads. Research has established that no aging mechanisms are measurable below 10^4 rads (Attachment C) for materials and most components supplied in safety-related electrical equipment. Some devices may have performance limitations below 10^4

rads. For radiation doses in excess of 10^4 rads, the equipment is irradiated using a gamma (γ) source to a dose equivalent to the estimated dose to be incurred during normal operation for the target qualified life. The estimated doses employed are specified in the equipment qualification data package, Section 1.8.4, and are based on a 100 percent load factor, including appropriate margin. For Subprogram A equipment, the equivalent accident dose is usually applied before design basis event testing.

Humidity

The use of materials significantly affected by humidity is avoided. For equipment subject to high energy line break environments, the aging effects due to humidity during normal operation are judged to be insignificant compared to the effects of the high-temperature steam accident simulation. Therefore, no additional humidity aging simulation is required.

Seismic Aging

The potential aging effects of low-level seismic activity and some low-level, in-plant vibration are addressed by employing a simulation of two earthquakes of 50 percent of the magnitude of a safe shutdown earthquake before seismic testing of the aged equipment.

B.4.6 Synergism

An important consideration in aging is the possible existence of synergistic effects when multiple stress environments are applied simultaneously. The potential for significant synergistic effects is addressed by the conservatisms inherent in using the "worst-case" aging sequence, conservative accelerated aging parameters and conservative, design basis event test levels which provide confidence that any synergistic effects are enveloped.

B.4.7 Design Basis Event Testing

Design basis event testing subsequent to equipment aging is discussed in Appendix 3D as to guidelines for defining high-energy line break environments and seismic conditions. Testing for equipment specific test environments and seismic parameters is discussed in Attachment A, Section 3.0.

B.4.8 Aging Sequence

The aging mechanisms applied to equipment subject to high-energy line break environments are determined by definition of the aging environments at the equipment location and by a subsequent evaluation of the sensitivity of the equipment to these environments. If the sensitivity of the equipment is not known, aging mechanisms are simulated by conservative methods as previously described. Those aging mechanisms that are simulated for typical equipment subject to high-energy line break environments are shown in Table 3D.B-2.

The order in which each of the aging mechanisms is applied is as shown in Table 3D.B-2. This order is considered to be conservative, as no aging mechanism is anticipated to be capable of reducing the impact of the previously applied mechanisms. As an example, thermal aging is applied before radiation aging to preclude the annealing out of radiation-induced defects.

Similarly, the effects of mechanical aging are considered more significant when applied to equipment that has already been preaged to address thermal and radiation phenomena.

B.4.9 Performance Criterion

The basic acceptance criterion is that the qualification tests demonstrate the capability of the aged equipment to perform prespecified, safety-related functions consistent with meeting the performance specification of Attachment A, Section 1.7 of the applicable equipment qualification data packages while exposed to the associated environmental conditions defined in Attachment A, Section 1.8.

B.4.10 Failure Treatment

When thermal aging is simulated at an equipment level, a conservative value for the activation energy is assumed for the components composing the equipment. As a consequence, many components are grossly overaged, and failure of some of the components is expected during the aging simulation. When three test units are preaged, in the event of such failure(s), one of the following options is selected.

- when a particular component fails in one of the three test units, the failure is considered random. The failed component is replaced by a new component, and the test is continued
- when a particular component fails in more than one of the three test units, either:

    1. the failed components are replaced by new identical components and the aging simulation continued. The claimed qualified life of the unit is consistent with the minimum aging period simulated by at least two of the three units; or
    2. the failed components is replaced by identical components specifically aged to the qualified life by assuming for thermal aging a less conservative activation energy specifically determined for the component, or
    3. the failed components are replaced by a different type of component which is aged for a period equal to the test units.

When less than three test samples prevent such a conclusion from being reached, any failures are investigated to ascertain whether the failure mechanism is of common mode origin. Should a common mode failure mechanism be identified as having caused the failure, a design change is implemented to eliminate the problem. Supplemental or repeat tests will be completed to demonstrate compliance with the acceptance criteria.

B.5 Subprogram B

Subprogram B includes Class 1E equipment not required to perform a safety related function in a high-energy line break environment. It involves a review of available information to demonstrate the absence of significant in-service aging mechanisms. For equipment allocated to this subprogram, the single design basis event capable of producing an adverse environment at the equipment location is the seismic event. Seismic testing completed on unaged equipment is

verified as valid by demonstrating via this subprogram that no available information suggests that aged materials and components would not continue to meet their design specification during a seismic event.

B.5.1 Scope

Subprogram B includes both a review of material analysis and the results of a component testing program for equipment not required to perform a safety-related function in a high-energy line break environment. Equipment is included that is required to mitigate high-energy line breaks but which, because of the equipment location, is isolated from the adverse environment resulting from the accident. Typical equipment allocated to Subprogram B is identified in Table 3D.B-1.

B.5.2 Performance Criteria

Available Material Analysis – For equipment and components for which aging is addressed by evaluation of appropriate mechanisms, the basic performance criterion is that the evaluation of test data demonstrates the effect of aging is minor and does not affect the capability of the aged equipment to perform prespecified functions. This is consistent with meeting the performance specification of Attachment A, Section 1.7 of the applicable equipment qualification data package while exposed to the associated environmental conditions defined in Attachment A, Section 1.8.

Available Component Aging Data – Random component failure or unacceptable performance due to aging is detected by routine maintenance and equipment calibration during service. The objective of Subprogram B is to provide reasonable assurance that a seismic event does not constitute a common mode failure mechanism capable of inducing unacceptable performance characteristics in aged components. Consequently, the single performance criterion for the aging portion of the qualification sequence requires that the component not fail to perform its general function, not that the component meets the original design and procurement specifications.

For the seismic event simulation, the component is considered acceptable if, during and after the simulation, it does not exhibit any temporary or permanent step change in performance characteristics. Failure of one of three components tested is considered a random failure, subject to an investigation concluding the observed failure is not common mode.

B.5.3 Failure Treatment

In the event of failure to demonstrate conformance to criteria, the following options are available for resolution of qualification with respect to age:

- Establish a maintenance and surveillance program

- Replace the materials or components with those constructed of materials of known acceptable characteristics.

Table 3D.B-1

TYPICAL CLASS 1E EQUIPMENT SCOPE AND SUBPROGRAM ALLOCATION

Aging Method	Equipment
Subprogram A	Valve Motor Operators Solenoid Valves Externally Mounted Limit Switches Pressure Transmitter (Group A) Differential Pressure Transmitter (Group A) Resistance Temperature Detectors Neutron Detectors Pressure Sensor Batteries*
Subprogram B	Pressure Transmitter (Group B) Differential Pressure Transmitter (Group B) Main Control Board Switch Modules Recorders (Post-Accident Monitoring) Indicators (Post-Accident Monitoring) Instrument Bus Distribution Panels Instrument Bus Power Supply (Static Inverter) Motor Control Centers Integrated Protection Cabinets (IPC) Engineered Safety Features Actuation Cabinets (ESFAC) Logic Cabinets Reactor Trip Switchgear Reactor Coolant Pump Switchgear

Note:
* To comply with R.G. 1.158

Table 3D.B-2

AGING MECHANISM SEQUENCE

Equipment	Location	Subprogram	Burn-in	Aging Mechanisms						DBE	
				Thermal	Radiation	Mechanical	Vibration	Electrical	Seismic	Seismic	HELB
Safety-related Valve Motor Operators	I/C O/C	A A		X X	X X	X X	X X		X X	X X	X
Safety-related Solenoid Valves	I/C O/C	A A		X X	X X	X X	X X		X X	X X	X
Safety-related Externally Mounted Limit Switches	I/C O/C	A A		X X	X X	X X	X X		X X	X X	X
Pressure Transmitters	I/C&OC	A	X	X	X				X	X	X
Differential Pressure Transmitters	I/C&OC	A	X	X	X				X	X	X
Resistance Temperature Detectors: Well Mounted	I/C	A		X	X		X		X	X	X
Excore Neutron Detectors	I/C	A		X	X				X	X	X
Pressure Sensor	I/C	A							X	X	X

ATTACHMENT C

EFFECTS OF GAMMA RADIATION DOSES BELOW 10^4 RADS ON THE MECHANICAL PROPERTIES OF MATERIALS

C.1 Introduction

One potential common-mode failure mechanism to consider in the qualification of safety-related equipment is gamma radiation. As part of a qualification program, the effect of gamma radiation dose is considered for two purposes: as a component of the high-energy line break environment and as a potential aging mechanism that could reduce the capability of safety-related equipment to perform safety-related functions under design basis event conditions (seismic or high-energy line break).

The scope of this attachment is limited to consideration of the effect of radiation for that substantial portion of equipment that does not experience an adverse change in external environment as a result of a high-energy line break, and for which, therefore, the only gamma radiation concern is an in-service aging mechanism.

This attachment assumes that the equipment contains devices that have been selected for performance through the total integrated dose expected in service. For example, devices such as integrated circuits may have a limit of 1000 rads established, in which case the following discussion applies for its installed life. The information in this attachment is not adequate to be applied to equipment that must perform its function in a high-energy line break.

The primary purpose of equipment qualification is to reduce the potential for common-cause failures due to environmental effects during the qualified life. Random failures that inevitably occur inservice are accommodated by the redundancy and diversity of the design of safety-related systems. Furthermore, in-service maintenance and testing programs are designed to detect such random failures. The chances of two identical components that perform identical functions failing during the same limited time period in between routine tests considered insignificant because of the following:

- General low failure rate of components used in nuclear equipment
- Minor differences in component material or geometric tolerances or both
- Minor differences in operating environment.

Therefore, failures that are induced in components by normal background gamma radiation below 10^4 rads (10^3 rads for some devices) alone are considered to be random. Thus, the only gamma radiation concern addressed for equipment not subject to an adverse high-energy line break environment is the potential for an aging mechanism resulting in a deterioration in component properties such that, when subject to seismic stress, a common-cause failure results. When considering such a failure mode, the aging mechanism of concern is not one that affects the electrical properties of components but one that reduces the mechanical strength and flexibility of components.

C.2 Scope

This report summarizes available information concerning the effects of gamma radiation on material mechanical properties. It justifies that for a gamma dose of less than 10^4 rads there are no observable radiation effects that impact material mechanical properties. Of the materials investigated, only Teflon TFE is subject to an alteration of mechanical properties for a gamma dose of less than 10^5 rads. Information is drawn from several sources listed as references in Section C.5. They include various texts concerning radiation effects and damage and pertinent reports.

C.3 Discussion

The primary effects of gamma photons on materials are ionization, material heating (primarily at high dose rates, which is of negligible significance here), and some displacement damage caused by high-energy photons. Some other types of radiation have effects similar to those induced by gamma radiation. This allows the use of data obtained from exposure of material to an alternate radiation to provide limited information concerning the effects of exposure to gamma radiation.

For example, the primary consequence of fast-neutron bombardment of material is atom displacement. Therefore, if the effect of radiation on a material property is primarily dependent on atom displacement, it is inferred that for an equivalent dose (rads) of gamma and fast-neutron radiation, data obtained from neutron irradiation provides a conservative estimate of the effect of gamma irradiation in producing displacements.

The same type of inference is drawn for the ionization effect of charged particle (for example, electron, proton, alpha particle) irradiation. Charged particles do not have the penetration capability that gamma or neutron radiations exhibit as a result of extensive interaction between charged particles and atomic charge centers.

Table 3D.C-1 summarizes information derived from the listed references. The information relates to the effect of gamma radiation on material mechanical properties. Table 3D.C-1 presents either the threshold dose (that dose at which an effect on any mechanical property can first be detected) or, the dose that results in the identified effect. This provides a general indication of the susceptibility of material mechanical properties to gamma radiation.

An evaluation of the information available on inorganic materials summarized in Table 3D.C-1 shows that the mechanical damage threshold for gamma radiation is many orders of magnitude greater than 10^4 rads. For the organic materials listed in Table 3D.C-1, a histogram comparing threshold dose level and frequency of material susceptibility is provided. In instances for which a material threshold dose is not indicated in Table 3D.C-1, a threshold value is assumed which is one order of magnitude lower than the indicated damage dose. Where information is available, referenced documents indicate that the difference between threshold dose and 25 percent damage dose is about a factor of three. Thus, a factor of 10 supplies substantial margin in estimating the threshold dose level. Figure C-1 shows that any indications of mechanical property damage thresholds below 10^4 rads would be extremely unusual.

The references listed do not identify the existence of materials whose mechanical properties are deteriorated when exposed to a gamma radiation dose up to 10^4 rads. So it can be concluded that

common-cause failures do not occur in electrical equipment during or after a seismic event as a result of radiation-induced degradation up to 10^4 rads.

This is supported by NRC documentation available as an attachment to "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors," which provides further justification for the use of 10^4 rads as a threshold for mechanical damage. The NRC information appears to be consistent with the information provided in Table 3D.C-1.

C.4 Conclusions

For Class 1E equipment subject to a lifetime gamma dose of up to 10^4 rads, it is not necessary to address radiation aging for qualification purposes provided that the equipment is not required to perform a safety-related function in a high-energy line break environment.

As previously noted, this appendix does not apply to electrical properties of components in safety-related equipment.

C.5 References

1. Ricketts, L. W., "Fundamentals of Nuclear Hardening of Electronic Equipment," R. G. Krieger Publishing Co., 1986.

2. NASA Tech Brief Vol. 10, No. 5, Item #3, "Response of Dielectrics to Space Radiation," October 1986.

3. IRT Study 4331-006, "Design Guidelines for Transient Radiation Effects on Tactical Army Systems," Harry Diamond Labs, June 12, 1981.

4. Regulatory Guide 1.89, Rev. 1.

5. Hanks, C. L., and Hamman, D. J., "The Effect of Radiation on Electrical Insulating Materials," REIC Report No. 46, Radiation Effects Information Center, Battelle Memorial Institute, Columbus, Ohio, June 1969.

6. Kangilaski, M., "The Effects of Neutron Irradiation on Structural Materials," REIC Report No. 45, Radiation Effects Information Center, Battelle Memorial Institute, Columbus, Ohio, June 1967.

7. Hanks, C. L., and Hamman, D. J., "The Effect of Nuclear Radiation on Capacitors," REIC Report No. 44, Radiation Effects Information Center, Battelle Memorial Institute, Columbus, Ohio, December 1966.

8. Chapin, W. E., Drennan, J. E., and Hamman, D. J., "The Effect of Nuclear Radiation on Transducers," REIC Report No. 43, Radiation Effects Information Center, Battelle Memorial Institute, Columbus, Ohio, October 1966.

9. Drennan, J. E., and Hamman, D. J., "Space Radiation Damage to Electronic Components and Materials," REIC Report No. 39, Radiation Effects Information Center, Battelle Memorial Institute, Columbus, Ohio, January 1966.

10. Larin, F., "Radiation Effects in Semiconductor Devices," John Wiley and Sons, New York, 1968.

11. Billington, D. S., and Crawford, J. H., "Radiation Damage in Solids," Princeton University Press, Princeton, New Jersey, 1961.

12. Corbett, J. W., "Electron Radiation Damage in Semiconductors and Metals," Academic Press, New York, 1966.

13. Ricketts, L. W., "Fundamentals of Nuclear Hardening of Electronic Equipment," Wiley-Interscience, New York, 1972.

14. Kircher, J. F., and Bowman, Richard E., "Effect of Radiation on Materials and Components," Reinhold Publishing Corp., New York, 1964.

15. Bolt, R. O., and Carroll, J. G., "Radiation Effects on Organic Materials," Academic Press, New York, 1963.

16. Kaplan, Irvin, "Nuclear Physics," Addison-Wesley, 1962.

Table 3D.C-1 (Sheet 1 of 2)

RADIATION-INDUCED DEGRADATION OF MATERIAL MECHANICAL PROPERTIES

Material	Mechanical Damage	Threshold Dose for Comments
Structural Metals	10^{19} n/cm^2 (fast neutron spectrum)	Similar to cold work (10^{10} rads)
Inorganic Materials	~10^{17} n/cm^2 (fast neutron spectrum)	Borated materials have lower threshold values for neutron irradiation.
Elastomers		
Natural Rubber	$2x10^6$ rads(C)	
Polyurethane Rubber	$9x10^5$ rads(C)	
Styrene-Butadiene Rubber	$2x10^6$ rads(C)	
Nitrile Rubber	$7x10^6$ rads(C)	Compression set is 25% degraded
Neoprene Rubber	$7x10^6$ rads(C)	
Hypalon	~10^7 rads(C)	Variable
Acrylic Rubber	$9x10^7$ rads(C)	Variable
Silicone Rubber	10^7 rads(C)	~25% damage
Fluorocarbon Rubber	$9x10^7$ rads(C)	~25% hardness, 80% elongation
Polysulfate Rubber	10^8 rads(C)	
Butyl Rubber	10^7 rads(C)	~25% damage
One rad (C) is the field of radiation that will produce 100 ergs/gm in carbon.		
Plastic		
Teflon TFE	$1.7x10^4$ rads(C)	
Kel-F	$1.3x10^6$ rads(C)	
Polyethylene	$\geq 10^7$ rads(C)	
Polystyrene	10^8 rads	
Mylar	10^6 rads(C)	Conservative
Polyamide (Nylon)	$8.6x10^5$ rads(C)	
Diallyl Phthalate	10^8 rads(C)	
Polypropylene	10^7 rads(C)	
Polyurethane	$7x10^8$ rads(C)	

Table 3D.C-1 (Sheet 2 of 2)

RADIATION-INDUCED DEGRADATION OF MATERIAL MECHANICAL PROPERTIES

Material	Mechanical Damage	Threshold Dose for Comments
Plastic (Continued)		
Kynar (400)	10^7 rads(C)	
Acrylics	$8.2x10^5$ rads	
Amino Resins	10^6 rads	
Aromatic Amide-Imide		
Resins	10^7 rads	
Cellulose Derivatives	$3x10^7$ rads	25% damage
Polyester, Glass Filled	$8.7x10^8$ rads	
Phenolics	$3x10^8$ rads(C)	25% damage
Silicones	10^8 rads(C)	
Polycarbonate Resins	$5x10^7$ rads	25% damage to elongation
Polyesters	~ 10^5 - 10^6 rads	
Styrene Polymers	$4x10^7$ rads(C)	
Styrene Copolymers	$4x10^7$ rads(C)	25% damage
Vinyl Polymers	$1.4x10^6$ – $8.8x10^7$ rads(C)	
Vinyl Copolymers	$1.4x10^6$ – $8.8x10^7$ rads(C)	
Encapsulating Compounds		
RTV 501	$2x10^6$ rads	
Sylgard 182	$2x10^6$ rads	
Sylgard 1383	$2x10^6$ rads	
Polyurethane Foam	$2x10^6$ rads	
Epoxies	10^9 rads	

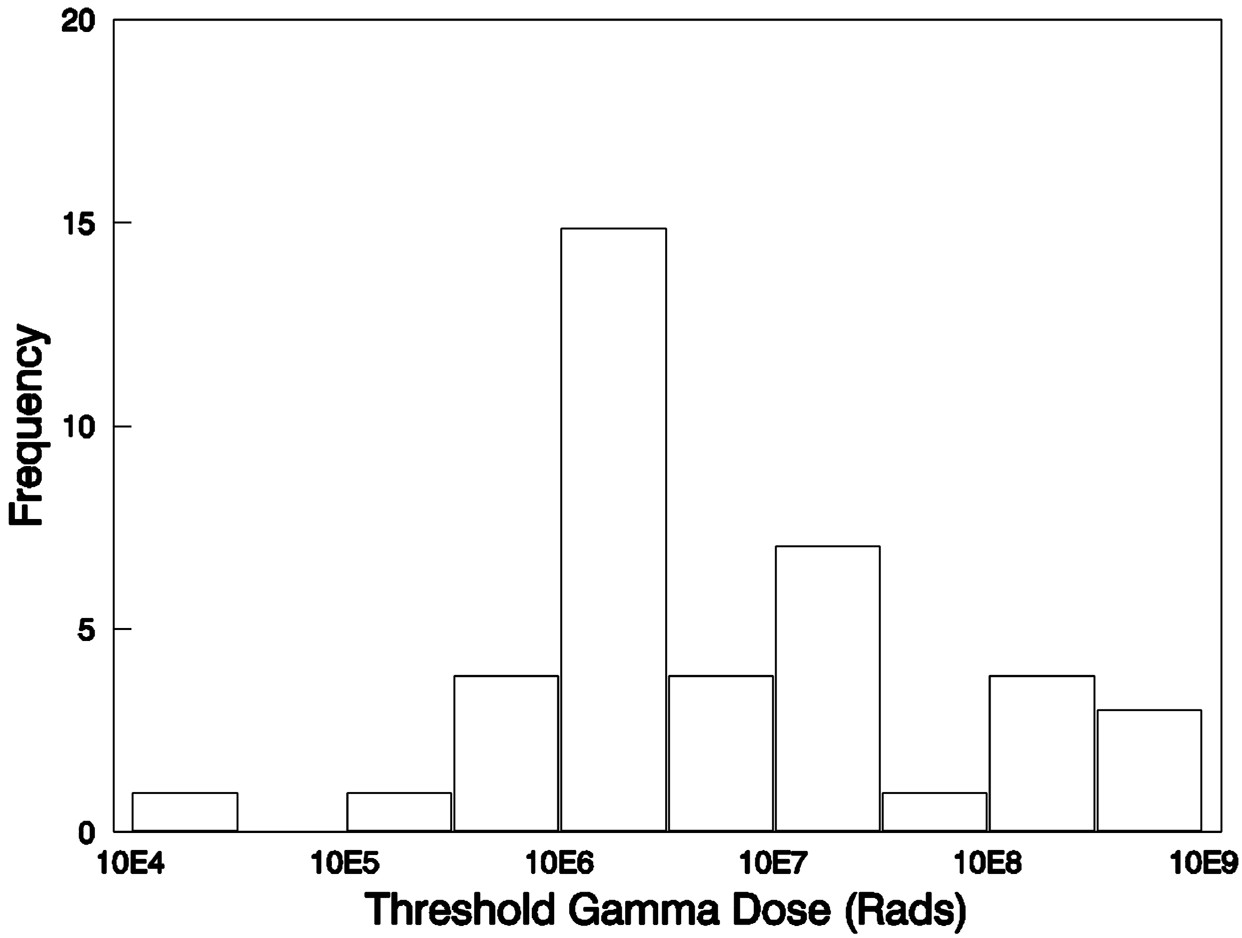


Figure 3D.C-1

Histogram of Threshold Gamma Dose for Mechanical Damage to Elastomers, Plastics, and Encapsulation Compounds

ATTACHMENT D

ACCELERATED THERMAL AGING PARAMETERS

D.1 Introduction

Attachment B describes the approach employed in the AP1000 equipment qualification program to address the aging requirement of IEEE 323. For equipment required to perform a safety-related function in a high-energy line break environment, the AP1000 equipment qualification program includes an aging simulation as part of its qualification test sequence (Subprogram A of Attachment B).

For equipment not required to perform a safety related function in a high-energy line break environment, the single design basis event considered is a seismic event. Aging, in this case (Subprogram B of Attachment B) is not usually included in the test sequence. Aging, where significant, is addressed by separate qualification of aged components, using conservative testing under applicable seismic design basis event conditions.

Thermal effects are one of the primary aging mechanisms addressed by the AP1000 equipment qualification program described in Attachment B for equipment containing nonmetallic or nonceramic materials. When thermal aging effects are established as potentially significant to the capability of the component or equipment to perform its safety-related function under design basis event conditions, or in the absence of evidence to the contrary, the component or equipment is thermally aged to simulate an end-of-qualified-life condition before design basis event testing. Equipment required to operate in a high-energy line break environment is also thermally aged to simulate the post-accident conditions consistent with its established functional requirements.

This attachment defines the appropriate thermal environments considered for each item of equipment in the AP1000 equipment qualification program and establishes consequent accelerated thermal aging parameters for use in the qualification programs.

D.2 Arrhenius Model

If an aging mechanism is governed by a single chemical reaction, the rate of which is dependent on temperature alone, the Arrhenius equation can be used as the basis for establishing the accelerated aging parameters:

$$\frac{dR}{dt} = Ae^{\frac{-E}{kT}} \tag{1}$$

where:

E = activation energy (eV)
k = Boltzmann's constant (8.62×10^{-5} eV/°K)
A = constant factor

T = material temperature (°K)

$\frac{dR}{dt}$ = reaction rate = aging rate

Integration gives:

$$\Delta R = Be^{\frac{-E}{kT}} \Delta t \qquad (2)$$

where:

ΔR = change in measured property due to aging
Δt = time for aging effect ΔR to occur
B = constant factor

If the accelerated aging process employed correctly simulates the change in properties due to aging under normal operating or post-accident temperature conditions, then:

$$\Delta R_1 = \Delta R_0 \qquad (3)$$

and

$$B\,T_1\,e^{\frac{-E}{kT_1}} = B\,T_0\,e^{\frac{-E}{kT_0}}$$

and

$$\text{Ln}\ t_1 = \frac{-E}{k}\frac{T_1 - T_0}{T_1 T_0}$$

where:

T_1 = accelerated aging material temperature (°K)
t_1 = time at temperature T_1
T_0 = material temperature under normal operating or post-accident conditions (°K)
t_0 = time at temperature T_0

From Equation 3, given an activation energy (E) for the material, the time required at any selected elevated temperature can be calculated to simulate the ambient aging effects.

This model has been verified to represent the thermal aging characteristics of nonmetallic and non-ceramic materials and is employed in the AP1000 equipment qualification program to derive accelerated thermal aging parameters. The only material dependent parameter input into this model, when establishing the accelerated aging parameters, is the activation energy. This parameter is a direct measure of the chemical reaction rate governing the thermal degradation of the material.

D.3 Activation Energy

A single material may have more than one physical property that thermally degrades (for example, dielectric strength, flexural strength.) As a consequence, the material exhibits different activation energies with respect to each property. The activation energy selected is the one that reflects the physical property most significant to the safety-related function performed or the stresses applied to the material by the design basis fault(s) considered.

In actual practice, however, rarely is the choice so simple. Electrical components are invariably made up of more than one material. In many cases either the materials employed are not known in any chemical detail but just by a general organic or industrial trade name, or the appropriate activation energy is not known.

Where an activation energy is not available that reflects the material or component as well as the physical property of interest, a single conservative activation energy is used.

A distribution of activation energies (Figure 3D.D-1) was produced by EPRI (Reference 1) based on 170 materials. An independent review of materials used in Westinghouse-supplied equipment is summarized in Table 3D.D-1 and plotted in similar form in Figure 3D.D-2. A statistical analysis indicates that 95 percent of the activation energies exceed about 0.4 eV from the EPRI data and 0.6 eV from the Westinghouse data. Based on this information, a value of 0.5 eV is selected for use throughout this program whenever specific activation energies are not available. Employing a low value of activation energy in deriving the accelerated aging parameters causes materials having a high activation energy to be overaged with respect to the simulated conditions.

D.4 Thermal Aging (Normal/Abnormal Operating Conditions)

This section establishes the methodology employed and derives a typical set of accelerated aging parameters for equipment in various plant locations.

D.4.1 Normal Operation Temperature (T_0)

In determining the ambient operating temperature (T_0) of the component/material/equipment under investigation, the following is considered:

- External ambient temperature (T_a)
- Temperature rise in cabinet/enclosure (T_r)
- Self-heating effects (T_j)

where $T_o = T_a + T_r + T_j$

D.4.1.1 External Ambient Temperature (T_a)

a) For equipment located in areas supplied by an air-conditioning system, a typical value assumed for (T_a) throughout the qualified life is 68°F (20°C). For air-conditioning systems, two excursions per year to 91°F (33.3°C), each lasting 72 hours, has a negligible additional aging effect.

b) For equipment located in areas supplied by a ventilation system, a typical value assumed (T_a) throughout the qualified life is 77°F (25°C). Two excursions per year to 122°F (50°C), each lasting 72 hours, has a negligible additional aging effect.

D.4.1.2 Temperature Rise in Enclosure (T_r)

This temperature rise is estimated based on the heat generated (radiative and conductive) by equipment inside or attached to the enclosure. For example, limit switches may be affected by process heat through the valve. Temperatures measured during test runs may be available. A typical value for temperature rise inside an electronics cabinet is 10°C.

D.4.1.3 Self-Heating Effects (T_j)

For equipment that is energized during most of its life, a self-heating effect is measured or established. If the equipment is energized only for short durations, this effect may be determined to be negligible. Temperature effects due to the solenoid of an energized valve may be significant (over 40°C). In determining junction temperatures of semiconductor devices, known operating parameters along with the thermal impedance are used. If the power dissipation is not known, a 50 percent operating stress is assumed.

D.4.2 Accelerated Aging Temperature (T_i)

Temperatures used for actual accelerated thermal aging tests are determined based on the equipment or component specifications in an attempt to prevent damage from high temperature alone and second-order (non-Arrhenius) effects such as the glass transition temperature of plastics. A maximum of 130°C is typically used for electronic component aging, but this is evaluated on a case basis. If the device is energized during the accelerated aging process, the self-heating effect as determined in the preceding section is added to the oven temperature to determine the total aging temperature (T_i).

D.4.3 Examples of Arrhenius Calculations

D.4.3.1 For a Normally Energized Component Aged Energized – The Self-Heating Effect is Added to Both (T_o) and (T_i):

Conditions:

T_a = 25°C, T_r = 10°C
T_j = 25°C, eV = 0.5,
Aging time = t_i
Oven temperature = 130°C
Qualified life goal = 10 years

Therefore

T_o = 25 + 10 + 25 = 60°C = 333°K
T_i = 130 + 25 + 155°C = 428°K

$$t_1 = 10e \; \frac{-0.5}{K} \frac{(428-333)}{(428 \times 333)} = 1831 \text{ hours}$$

D.4.3.2 For a Normally De-energized Component Aged Energized – the Self-heating Effect is Added Only to T_i:

Conditions: $T_a = 25°C$, $T_r = 10°C$
$T_j = 25°C$, eV = 0.5, Aging time = t_1
Oven temperature = 130°C
Qualified life goal = 10 years

Therefore $T_o = 25 + 10 = 35°C = 308°K$
$T_i = 130 + 25 + 155°C = 428°K$

$$t_1 = 10e\ \frac{-0.5}{K}\ \frac{(428-308)}{(428\times 308)} = 445 \text{ hours}$$

D.5 Post-Accident Thermal Aging

Most cases, some safety-related postaccident performance capability is specified by the functional requirements. As a consequence, to qualify equipment to IEEE 323, the effects of post-accident thermal aging must be simulated after the high-energy line break test. This section establishes the accelerated thermal aging parameters employed in performing this simulation.

D.5.1 Post-Accident Operating Temperatures

Assuming continuous operation of containment safeguards systems following an accident, the containment environment temperature is reduced to the external ambient temperature well within one year for any postulated high-energy line break. However, to allow for possible variations in plant operations following an accident, the limiting design high-energy line break envelope is assumed to remain constant at 155°F (68°C) between four months and one year. As indicated in Figure 3D.D-3, the limiting design profile post-accident is defined by the LOCA envelope (Figure 3D.5-6) starting at one day.

For safety-related equipment located inside containment, either the self-heating effects of the operating unit, under post-accident conditions, may be insignificant compared to the heat input from the external environment (transmitters, RTDs), or the unit may not be in continuous operation during this phase (valve operators). So it may not be necessary to add a specific temperature increment to account for self-heating of these devices following an accident. The profile reproduced here as Figure 3D.D-3 is then input at T_0 into the Arrhenius equation to calculate appropriate accelerated aging parameters for post-accident conditions. However, as noted in Section D.4, if the equipment is energized during the aging simulation period, the self-heating effect is added to both T_o and T_i.

D.5.2 Accelerated Thermal Aging Parameters for Post-Accident Conditions

The aging temperature most often used for post-accident simulation is 250°F (121°C). This temperature is selected as a maximum for electronic components and is generally used for tests. Using this value and the conservative activation energy of 0.5 eV, the Arrhenius equation is applied to the curve in Figure 3D.D-3 from one day to four months or to one year in small increments of time. The required aging times to simulate these small increments are then summed

to yield a total test time of 42 days to simulate four months and about 67 days to simulate one year post-accident operation. Including appropriate margin adds four and seven days respectively to the total test time.

If an activation energy of 0.8 eV is justified, the Arrhenius equation yields 19 days to simulate four months and 26 days to simulate one year with two days and three days margin to be included in the total test time.

D.6 References

1. EPRI NP-1558, Project 890-1, "A Review of Equipment Aging Theory and Technology," September 1980.

Table 3D.D-1 (Sheet 1 of 2)

ACTIVATION ENERGIES FROM WESTINGHOUSE REPORTS

Material	Electron Volts
Melamine-Glass, G5	0.29
Epoxy B-725	0.48
Ester-Glass, GPO-3	0.57
RTV Silicone	0.60
Phenolic-Asbestos, A	0.61
Nylon 33 GF	0.70
Acetal	0.73
Mineral Phenolic	0.74
Silicone Varnish	0.74
Polypropylene	0.81
Polysulfone	0.83
Phenolic-Cotton, C	0.84
Formvar	0.85
Epoxy	0.88
Epoxy Adhesive	0.89
Nylon	0.90
Pressboard	0.91
Kapton	0.93
Silicone	0.94
Phenolic-Asbestos, A	0.94
Cast Epoxy	0.98
Urethane-Nylon	0.99
Phenolic-Glass, G-3	1.01
Polycarbonate	1.01
Phenolic-Paper, X	1.02
Epoxy Wire	1.05
Epoxy-Glass, FR-4	1.05
Varnish Cotton	1.06
PVC	1.08
Ester-Glass, GPO-1	1.09
Cellulose Phenolic	1.10
X-Link Ethylene	1.11
Urethane	1.12
Ester-Glass, GPO-2	1.13
Ester-Nylon	1.14

Table 3D.D-1 (Sheet 2 of 2)

ACTIVATION ENERGIES FROM WESTINGHOUSE REPORTS

Material	Electron Volts
Ester-Glass, GPO-1	1.16
32102BK Varnish	1.16
Vulcanized Fiber	1.16
Cellulose Mineral Phenolic	1.17
Mylar	1.18
Cast Epoxy	1.18
32101EV Varnish	1.18
Epoxy	1.18
Silicone	1.18
Phenolic-Paper, XX	1.20
Vulanized Fiber	1.21
Cellulose Phenolic	1.24
Phenolic-Glass, G-3	1.24
Kraft Phenolic	1.25
Neoprene	1.26
Amide-Imide Varnish	1.31
Loctite 75	1.38
Acetyl. Cotton	1.39
Silicone-Asbestos	1.41
Epoxy-Glass, FR-4	1.50
Mylar	1.58
Nomex	1.59
Omega Varnish	1.59
Epoxy-Glass, G-11	1.64
Polythermaleze	1.64
Kraft Paper	1.67
Valox 310SE-0	1.75
Varnished Kraft	1.86
Nomex	1.91
Ester-Glass, GPO-3	2.03
Phenolic-Cotton, C	2.12
Melamine-Glass, G-5	2.18

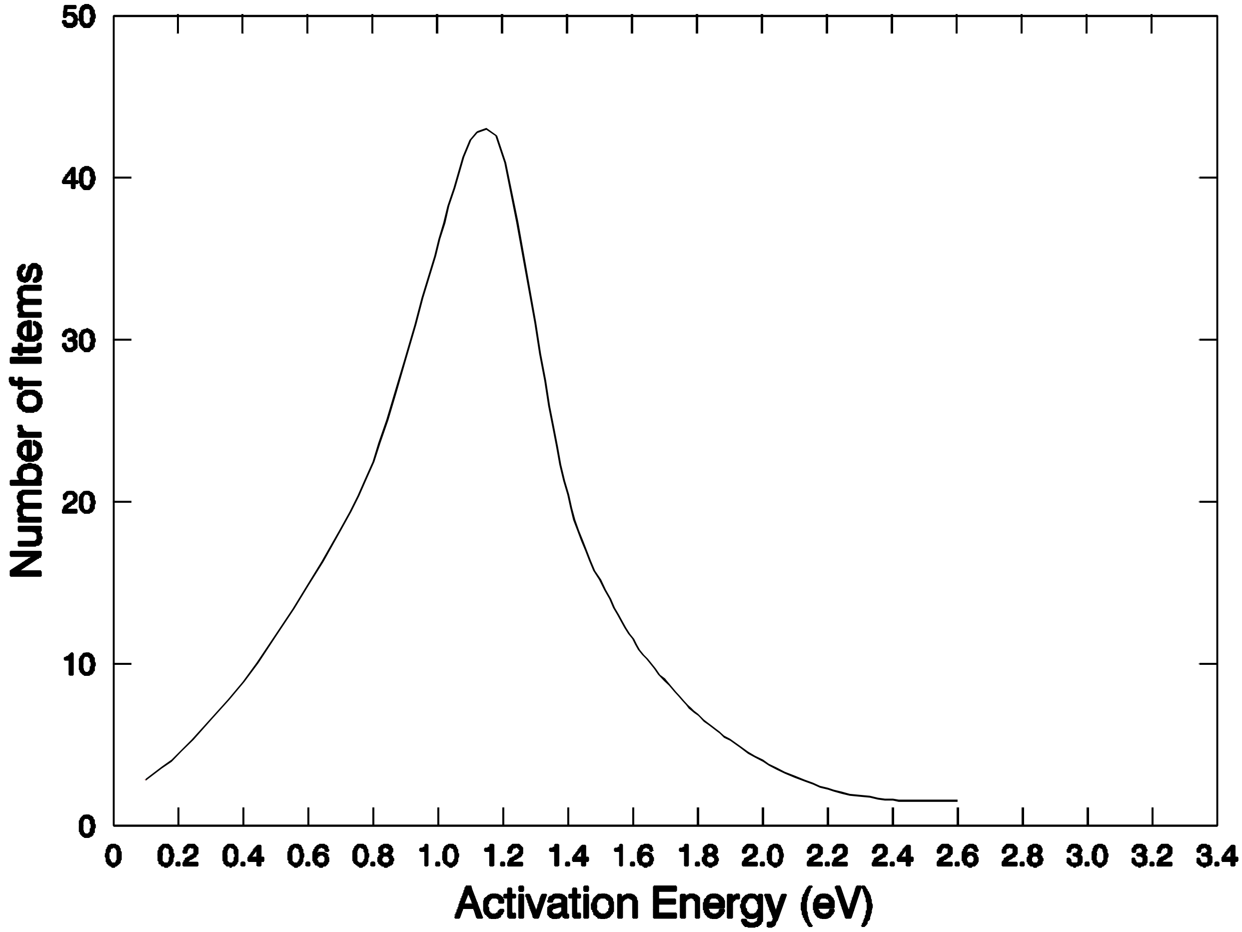


Figure 3D.D-1

Frequency Distribution of Activation Energies of Various Components/Materials (EPRI Data)

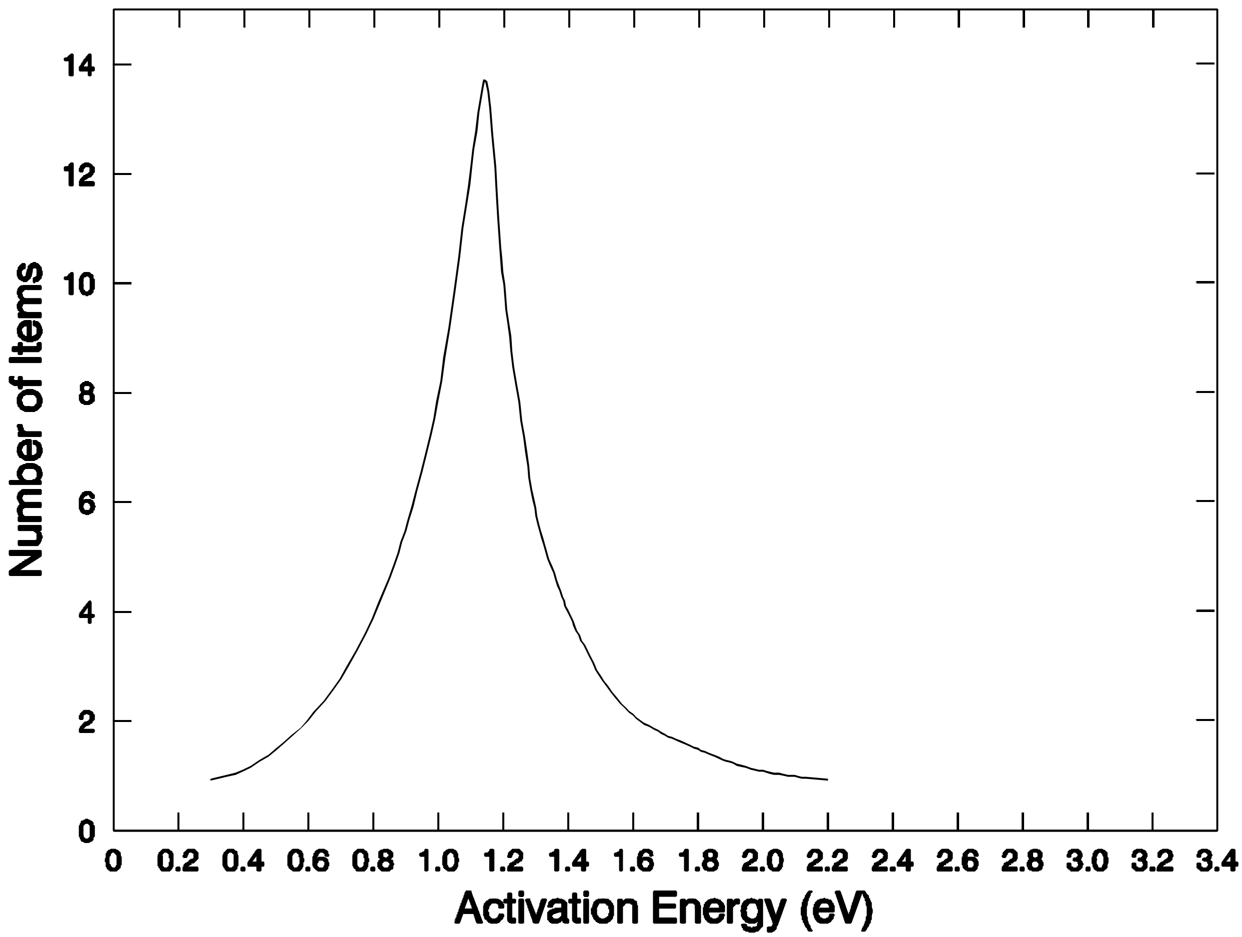


Figure 3D.D-2

Frequency Distribution of Activation Energies of Various Components/Materials (Westinghouse Data)

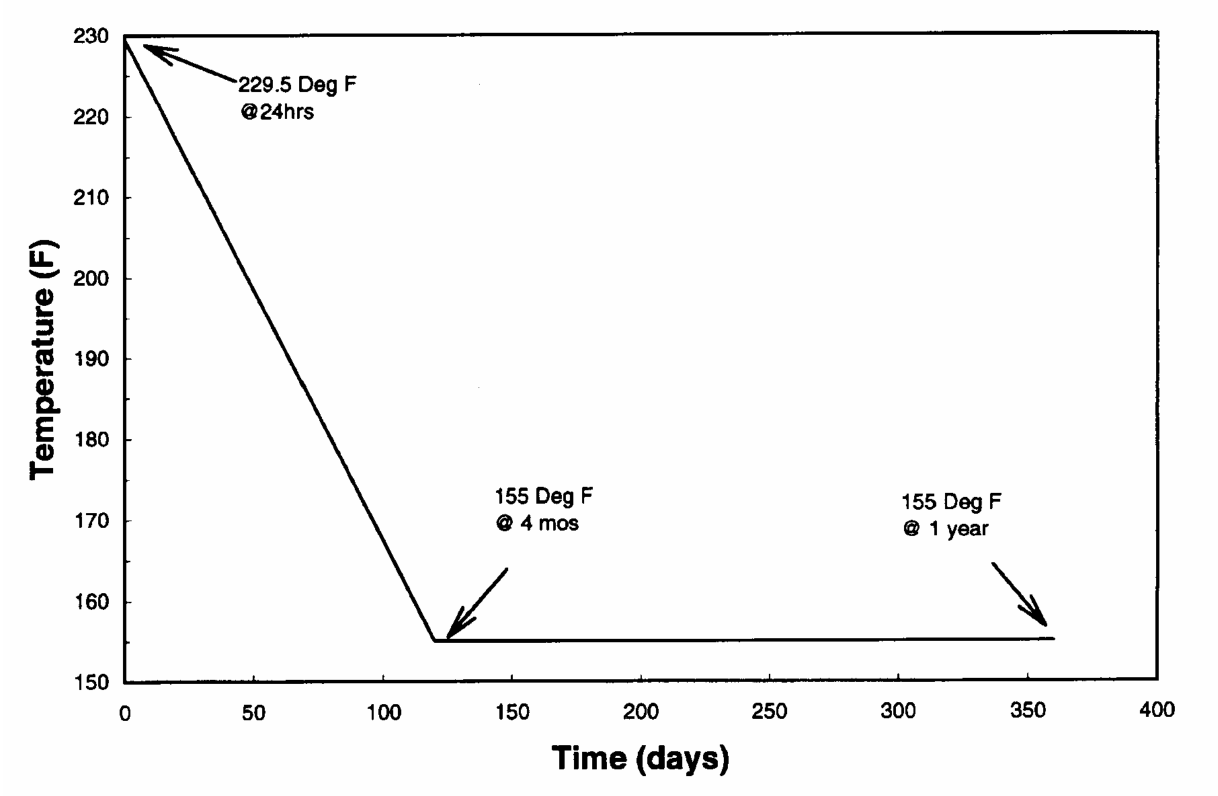


Figure 3D.D-3

Post-Accident Temperature Profile

ATTACHMENT E

SEISMIC QUALIFICATION TECHNIQUES

E.1 Purpose

The following is the methodology used to seismically qualify Seismic Category I mechanical and electrical equipment for the AP1000 equipment qualification program. Qualification work covered by this appendix meets the applicable requirements of IEEE 344-1987 and 382-1985.

The design and mounting of non-safety related equipment located in close proximity of seismic Category I equipment is not covered by this document.

E.2 Definitions

The following are definitions of terms unique to or distinct from common industry usage. (See Section E.4.2.)

E.2.1 1/2 Safe Shutdown Earthquake

The 1/2 safe shutdown earth (SSE) is the earthquake level used during seismic testing to seismically age safety-related equipment before performing safe shutdown earthquake testing.

E.2.2 Seismic Category I Equipment

Seismic Category 1 equipment consists of structures, systems, and components required to withstand the effects of the safe shutdown earthquake and remain structurally intact, leak-tight (in case of pressurized systems), and functional to the extent required to perform their safety-related function.

E.2.3 Active Equipment

Equipment that must perform a mechanical or electrical operation during or after (or both) the safe shutdown earthquake in order to accomplish its safety-related function.

E.2.4 Passive Equipment

Equipment where maintenance of structural or pressure integrity is the only requirement necessary for accomplishing its safety-related function.

E.3 Qualification Methods

This section presents a general description of the seismic qualification methods used by AP1000 for the seismic qualification of Seismic Category I safety-related mechanical and electrical equipment. Three methods are used: test, analysis, and a combination of the two. The approaches for qualification by testing and by analysis are discussed in Section E.5 and Section E.6, respectively. The following discussion covers the conditions under which each approach is used

and the general requirements applicable to the use of the methods. The qualification sequence is defined in Appendix 3D.

E.3.1 Use of Qualification by Testing

The preferred method for seismic qualification of safety-related Class 1E electrical and electromechanical equipment is seismic testing. The nature of the seismic and vibrational input used depends on where the equipment is used. For equipment mounted so that the seismic environment includes frequency content between 1 and 33 hertz (hard mounted), the seismic test input is multifrequency. For equipment mounted so that seismic ground motion is filtered to contain one predominant structural mode (line mounted), single frequency testing is appropriate. This is the case for equipment mounted on piping systems, ductwork, or cable trays.

E.3.2 Use of Qualification by Analysis

Analysis is used for seismic qualification when one of the following conditions is met:

- The equipment is too large or the interface support conditions cannot adequately be simulated on the test table.

- The only requirement is to maintain structural integrity during a postulated seismic event.

- The equipment represents a linear system, or the nonlinearities can conservatively be accounted for in the analysis. This approach is also applicable to the development of the seismic environment, required response spectrum curve, at the mounting location of a component attached to a larger structure when the device is seismically qualified by separate component testing.

- The analysis is used to document the seismic similarity of the equipment provided and that previously qualified by testing.

Seismic qualification of safety-related electrical equipment by analysis alone is not permitted.

E.4 Requirements

E.4.1 Damping

Damping level of a component or system describes its capability to dissipate vibrational energy during a seismic event. The damping level used defines the response magnitude of an ideal single degree of freedom linear oscillator when subjected to the specified input as documented by the required response spectrum (RRS) curve. The significance of the damping value used depends on whether qualification is by testing or analysis.

E.4.1.1 Testing

Equipment qualification by testing involves subjecting the base of the equipment to a representative seismic acceleration time history. The response characteristics of the equipment are a function of the inherent damping present in the equipment. In this case the damping value used

(typically five percent) serves as a convenient means of showing the compliance of the test response spectrum (TRS) with the required response spectrum.

E.4.1.2 Analysis

In the case of qualification by analysis, the damping level used is representative of the damping actually present in the equipment. Unless other documented equipment damping data is available, the values specified in Table 3.7.1-1 of Chapter 3 are used.

E.4.2 Interface Requirements

As part of the seismic qualification program, consideration is given to the definition of the clearances needed around the equipment mounted in the plant to permit the equipment to move during a postulated seismic event without causing impact between adjacent pieces of safety-related equipment. This is done as part of seismic testing by measuring the maximum dynamic relative displacement of the top and bottom of the equipment.

When performing qualification by analysis, the relative motion is obtained as part of the analytical results. These motions are reported in the qualification report and are used to determine the required clearance between adjacent pieces of equipment.

In addition, the qualification program takes into account the restraining effect of other interfaces, such as cables and conduits attached to the equipment, which may change the dynamic response characteristic of the equipment. (Also See Section E.7.2.)

E.4.3 Mounting Simulation

The mounting conditions simulated by analysis or during seismic test are representative of the equipment as-installed mounting conditions used for the AP1000 equipment. When an interfacing structure exists between the safety-related equipment being qualified and the floor or wall at which the equipment mounting required response spectrum is specified, its flexibility is simulated as part of the qualification program. If this is not done, justification must be provided, demonstrating that the deviations in mounting conditions do not affect the applicability of qualification program. (See also Section E.7.2.)

E.4.4 1/2 Safe Shutdown Earthquake

The AP1000 makes use of a small earthquake having the intensity of one-half of the safe shutdown earthquake at the safety-related equipment mounting location to simulate the fatigue effects of smaller earthquakes that may occur before the postulated safe shutdown earthquake. These small earthquakes correspond to the operating basis earthquakes (OBEs) referenced in IEEE 344-1987. When qualification by testing is used, five of these small earthquakes are used to vibrationally age the equipment before the safe shutdown earthquake. When qualification by analysis is used, two safe shutdown earthquake events are used to simulate the fatigue aging effects. Each event contains 10 peak cycles. These stress cycles are used to verify that the equipment is not subject to failure due to low cycle fatigue.

E.4.5 Safe Shutdown Earthquake

The safe shutdown earthquake required response spectrum curve defines the seismic qualification basis for each piece of safety-related equipment. The seismic level varies according to the mounting location of the equipment. When equipment qualification is based on testing, an additional 10 percent test acceleration margin is added as specified in IEEE 323-1974.

E.4.6 Other Dynamic Loads

Hydrodynamic loads are considered as part of the qualification program, where applicable.

E.5 Qualification by Test

Seismic qualification testing is the preferred method for electrical, mechanical, and electromechanical equipment. The nature of the test input used depends on whether the equipment is hard mounted or line mounted. The test program consists of the following elements: environmental aging (if required), mechanical aging, vibrational aging, and safe shutdown earthquake testing. For those cases where the equipment is also subject to a loss of coolant or a high-energy line break accident, these accidents are simulated on the same qualification specimen after completion of the testing previously discussed. (See Sections 3D.4.4 and 3D.7.4.)

The characteristics of the required seismic and dynamic input motions should be specified by the response spectrum or time history methods. These characteristics, derived from the structures or systems seismic and dynamic analyses, should be representative of the input motions at the equipment mounting locations.

For seismic and dynamic loads, the actual test input motion should be characterized in the same manner as the required input motion, and the conservatism in amplitude and frequency content should be demonstrated (that is, the test response spectrum should closely resemble and envelop the required response spectrum over the critical frequency range).

Since seismic and the dynamic load excitation generally have a broad frequency content, multi-frequency vibration input motion should be used. However, single frequency input motion, such as sine beats, is acceptable provided the characteristics of the required input motion indicate that the motion is dominated by one frequency (for example, by structural filtering effects), or that the anticipated response of the equipment is adequately represented by one mode, or in the case of structural integrity assurance, that the input has sufficient intensity and duration to produce sufficiently high levels of stress for such assurance. Components that have been previously tested to IEEE-344-1971 should be reevaluated or retested to justify the appropriateness of the input motion used, and requalified if necessary.

For the seismic and dynamic portion of the loads, the test input motion should be applied to one vertical axis and one principal axis (or two orthogonal axes) simultaneously unless it can be demonstrated that the equipment response motion in the horizontal direction is not sensitive to the vibratory motion in the horizontal direction, and vice versa. The time phasing of the inputs in the vertical and horizontal directions must be such that a purely rectilinear resultant input is avoided. An acceptable alternative is to test with vertical and horizontal inputs in-phase, and then repeat the

test with inputs 180 degrees out-of-phase. In addition, the test must be repeated with the equipment rotated 90 degrees horizontally.

E.5.1 Qualification of Hard-Mounted Equipment

Hard-mounted equipment is seismically tested mounted on a test table capable of producing multifrequency, multiaxis inputs. The waveform characteristics of the input are random and scaled in such a way that the test response spectrum equals or exceeds the required response spectrum (including margin). The input signal meets the requirements of Section 7.6.3 of IEEE 344-1987.

Furthermore, the test input simulates the multidirectional nature of the earthquake. The preferred method for meeting this requirement is to the use a triaxial test table capable of producing three statistically independent, orthogonal input motions. In this case the seismic testing consists of five 1/2 safe shutdown earthquake tests and one safe shutdown earthquake test in one orientation.

Using a biaxial test table is acceptable if it is justified that the horizontal and vertical test inputs conservatively simulate the three-dimensional nature of the seismic event. One acceptable approach is to mount the equipment on the test table with its front-to-back axis oriented at 45 degrees to the horizontal drive axis and scale the horizontal component of the input by a factor of the square root of two. Statistically independent inputs are preferred and, if used, the test can be performed in two stages, with the equipment rotated 90 degrees about the vertical axis. In this case, the five 1/2 safe shutdown earthquake inputs need to be applied only in the first orientation.

If a dependent biaxial test table is used, the test is performed in four stages. The first stage involves five 1/2 safe shutdown earthquake tests and one safe shutdown earthquake test in the first orientation. The second, third, and fourth orientations are obtained by successively rotating the equipment 90 degrees clockwise from its previous position. One safe shutdown earthquake test is performed in each of the last three orientations.

Each multifrequency test has a minimum of 15 seconds of strong motion input. The strong motion portion is preceded and followed by a period of testing where the test input is ramped up and ramped down, respectively, so that the equipment is not subjected to impact loading. The adequacy of each test run is evaluated using the criteria set forth in Section 7.6.3.1 of IEEE 344-1987.

E.5.2 Qualification of Line-Mounted Equipment

Line-mounted equipment, because of the dynamic filtering characteristics of its mounting, is effectively subject to single frequency input. This condition is common for valves and sensors supported by piping systems, cable trays, and duct systems. This equipment is qualified consistent with the requirements of IEEE 382-1985.

In some cases this equipment may also be used in the hard-mounted condition. In this case multifrequency, multiaxis testing is also required unless justification is provided that the previous single frequency tests demonstrate the capability of the equipment to operate under the hard-mounted seismic conditions. Because of the large size of typical valves, it may be necessary to perform separate testing of the operators and valve assembly.

E.5.2.1 Seismic Qualification Test Sequence

The seismic qualification process is broken down into the following steps:

1. Mount the equipment on a rigid test fixture and perform a resonant search test to demonstrate that the equipment is structurally rigid (fundamental frequency greater than 33 hertz) and does not amplify the seismic motions acting at the valve mounting interface.

2. Perform single frequency testing on the line-mounted equipment.

3. Perform multifrequency, multiaxis testing on the equipment, if appropriate.

   If a valve assembly is seismically qualified, additional testing is needed:

4. Perform a static pull test on the valve.

5. Perform a static seismic analysis using a verified model of the valve and its extended structure to demonstrate that the valve has adequate structural strength to perform its safety-related function without exceeding the design allowable stresses specified in ASME Code, Section III, Subsection NB, NC, or ND for pressure-retaining parts, as appropriate, and Subsection NF for nonpressure-retaining parts.

E.5.2.2 Line Vibration Aging

Line-mounted equipment may be subject to operational vibrations resulting from normal plant operations. The potential fatiguing effect of this vibrational aging is simulated as part of the qualification program. This requirement is satisfied by subjecting the equipment to a sine sweep from 5 to 100 to 5 hertz at an acceleration level of 0.75g or such reduced acceleration at low frequencies to limit the double amplitude to 0.025 inch as specified in Section 5.3.1 of IEEE 382-1985.

E.5.2.3 Single Frequency Testing

The single frequency testing acceleration waveform is either sine beat or sine dwell applied at one-third octave frequency intervals as specified in IEEE 382-1985. Each dwell has a time length adequate to permit performance of functional testing, with a minimum time of 15 seconds. To account for the three-dimensional nature of the seismic event, the test input level is taken as the square root of two times the required input motion (RIM) level specified in IEEE 382. The level includes the 10 percent test margin. Each test series is performed using single axis input. The test series is performed successively in each of three orthogonal axes.

E.5.2.4 Seismic Aging

The aging effect of the five 1/2 safe shutdown earthquake earthquakes can be simulated by exposing the equipment to two sinusoidal sweeps at one-half of the safe shutdown earthquake required input motion level in each orthogonal axis. Each sweep shall go from 2 to 35 hertz to 2 hertz at a rate not to exceed one octave per minute. One sweep is performed with the equipment in its inactive mode, and the other with the equipment in its safety-related operational mode.

E.5.2.5 Static Pull Testing of Valves

The seismic testing just discussed is normally performed only on the valve operator and the attached appurtenances. If the valve assembly is rigid, the operability of the valve assembly during a postulated seismic event may be demonstrated by performing a static pull test using a peak acceleration value equivalent to a triaxial acceleration of 6g. If the valve assembly is determined to be flexible, a supplemental analysis of the seismic response of the flexible valve and its supporting piping is performed to determine the actual acceleration level present at the center of gravity of the valve assembly.

The valve is placed in a suitable test fixture with the operator and appurtenances mounted as in the normal valve. The valve is mounted so that the extended structure is freestanding and supported only by the valve nozzles. The valve is positioned so that the horizontal and vertical load components simulating the three-dimensional nature of the seismic event produce a worst-case stress condition in the valve extended structure.

During testing, the valve shall be internally pressurized. Static loads simulating dead weight and seismic loads are applied. The tests are normally performed at ambient temperature. These loads simulate to the extent feasible the load distribution acting on critical parts of the valve assembly. The valve is actuated using the actuator system seismically qualified according to IEEE 382-1985. The valve assembly is cycled from its normal to the desired safety-related position within the time limits defined in the equipment specification. Leakage measurements are made, where required, and compared to the allowable values specified in the valve design specification.

E.5.3 Operational Conditions

When equipment being qualified performs a safety-related function during the safe shutdown earthquake, the equipment is operated and monitored to demonstrate that the equipment functions properly before, during, and after the seismic event. If the test time is not long enough to complete the required functional tests, the length of the strong motion test time is increased to permit completion of the required functional testing.

Where functional testing is dependent on external electrical supply, the testing is performed using the worst-case electrical supply conditions.

E.5.4 Resonant Search Testing

Resonant search testing is performed to provide data on the natural frequency and dynamic response characteristics of the equipment qualified. For hard-mounted equipment being qualified by seismic testing, resonant search testing is done to provide additional information but is not required for qualification of the equipment. This is an important consideration because frequency testing for hard-mounted equipment is normally performed with the equipment mounted on the test table, where dynamic interaction of the table and the equipment has a significant effect on the measured natural frequency.

For qualification of line-mounted valve assemblies, it is necessary that the assemblies be rigid. To meet this requirement, the assembly mounted to a rigid test fixture so that the frequencies measured are indeed representative of the valve assembly. If it is not feasible to provide a rigid

fixture, as is likely the case when testing such very large valves, as the main steam and feedwater isolation valves, additional tests and analyses may be required to determine if the apparent flexibility measured is due to the test fixture or to the characteristic of the valve assembly itself.

If the resonant search test data is being generated to verify the accuracy of an analytical modeling technique, the test specimen mounting details must accurately simulate the boundary conditions used in the analytical model.

E.6 Qualification by Analysis

Section E.3.2 defines the limits on the use of analysis to demonstrate seismic qualification of safety-related equipment. The following sections describe the analytical methods to be employed for qualification of equipment. There are two techniques, static and dynamic, used to qualify equipment. The success of either method depends on the ability of the analytical model to describe the response of the system to seismic loads. Alternative methods of analysis are accepted if their conservatism is documented.

The analysis is used to demonstrate the structural adequacy of the equipment being qualified. This is done by showing that the calculated stresses do not exceed the design allowable stresses specified in ASME Code, Section III, Subsection NB, NC, or ND for pressure-retaining equipment and Subsection NF for nonpressure-retaining equipment.

E.6.1 Modeling

Analysis may be performed by hand calculations, finite element, or mathematical models that adequately represent the mass and stiffness characteristics of the equipment. The model contains enough degrees of freedom to adequately represent the dynamic behavior over the frequency range of interest. It includes the essential features of the equipment.

Dynamic properties reflect the in-service operating conditions, such as structural coupling, dynamic effects of contained liquids, and externally applied restraints (where appropriate). Where the modeled equipment exhibits some nonlinear behavior, this nonlinearity is modeled unless justification is provided that it is insignificant or that the linear model provides conservative results. The adequacy of the model or of the modeling techniques is shown by comparing the predicted responses to the responses predicted by benchmark problems or modal testing. Acceptable benchmark problems include hand calculations, analysis of the same problem using a comparable verified public-domain program, empirical data, or information from the technical literature.

In addition to documenting the modeling technique, a quality assurance program is in place that defines the requirements for the control, verification, and documentation for the computer programs used for qualification of safety-related equipment. The computer programs used in the qualification process are verified on the same computer on which the qualification analysis is performed.

E.6.2 Qualification by Static Analysis

For rigid equipment, the seismic forces resulting from one seismic input direction are calculated for each node point by multiplying the nodal mass in that direction by the appropriate zero period acceleration (ZPA) floor acceleration. The combined system response of the equipment to the simultaneous loads acting in all three directions is calculated by combining the three components, using the square root sum of the squares (SRSS) method. The square root sum of the squares method is used to account for the statistical independence of the individual orthogonal seismic components.

E.6.3 Qualification by Dynamic Analysis

If the lowest natural frequency of the equipment lies below the cutoff frequency, the response of the equipment to the seismic event in each orthogonal direction will be dynamically amplified and the equipment is said to be flexible. The analysis is performed in compliance with the guidelines set forth in the SSAR and in Regulatory Guides 1.92, 1.100, and 1.122.

The preferred method of analysis is the response spectrum method. In this method the responses in each equipment mode are calculated separately and combined by the square root sum of the squares method, provided the modes are not closely spaced. (Consecutive modes are said to be closely spaced if their frequencies differ from that of the first mode in the group by less than 10 percent.) The responses for each mode in a group are combined absolutely. The group response is then combined with the remaining modal responses using the square root sum of the squares method. The responses for each of the three orthogonal seismic components can then be combined as discussed in Section E.6.2. The applicable damping levels are noted in Table 3.7.1-1 of Chapter 3.

E.6.3.1 Response Analysis

Modes up to and including the cutoff frequency are included in this summation. In some cases, the structure is basically rigid, with some of the flexible mode representing local effects. This situation is evaluated by reviewing the modal masses applicable to a given seismic input direction. If the sum of the effective modal masses used in the response spectrum analysis is greater than 0.9 times the total equipment mass, the model is assumed to adequately represent the total equipment mass. If this criterion is not satisfied, it means that a significant part of the equipment seismic response is due to the static seismic response of the higher equipment modes (above the cutoff frequency). If this situation occurs, the analyst determines the component of the response due to the higher modes and combines it with the flexible response component by square root sum of the squares. (This requirement is discussed in the SSAR, Subsection 3.7.2.)

E.6.3.2 Static Coefficient Method

As an alternative to the response spectrum method, the static coefficient method of analysis may be used. In this method the frequencies of the equipment are not determined, but a static analysis is performed, assuming that a peak acceleration equal to 1.5 times the peak spectral acceleration given in the applicable required response spectrum acts on the structure.

E.6.3.3 Time History

The time-history method of analysis is the preferred method of analysis when the equipment exhibits significant nonlinear behavior or when it is necessary to generate response spectra for specific component mounting locations in the equipment. The acceptable methods that are used to develop the seismic time histories are discussed in Regulatory Guide 1.122, ASME Code, Section III, Appendix N, and in Section 6.2 of IEEE 344-1987.

E.7 Performance Criteria

E.7.1 Equipment Qualification by Test

The performance criterion for qualification of equipment is that the equipment successfully perform its safety-related function during and after the postulated seismic event. Acceptance requires, as a minimum, that:

- No spurious or unwanted outputs occur in the circuits that could impair the safety-related functional operability of the equipment;
- No gross structural damage of the equipment occur during the seismic event that could lead to the equipment or any part thereof becoming a missile. Local inelastic deformation of the equipment is permitted; and,
- Satisfactory completion of specified baseline tests are demonstrated before, during, and after the seismic test sequence.

E.7.2 Equipment Qualification by Analysis

E.7.2.1 Structural Integrity

The analysis verifies that the equipment, when subjected to the worst case combination of operating and seismic loads, maintains its structural integrity. In addition the analysis shows that the equipment is not subject to low cycle fatigue failure when subject to postulated seismic loading. Finally the analysis verifies that seismically induced equipment motion does not lead to impacting with other nearby equipment.

E.7.2.2 Operability

Analysis can be used to demonstrate equipment operability for those pieces of equipment where structural integrity or limitation of deformation guarantees operability. As an example the analysis of active equipment verifies that the combination of operating and postulated seismic loads do not produce stress levels or deformations that exceed established functional limits. The rationale for use of these limits is justified.

APPENDIX 3E

HIGH-ENERGY PIPING IN THE NUCLEAR ISLAND

This appendix identifies high-energy piping in the nuclear island with a diameter larger than 1 inch. Candidate leak-before-break piping is identified in Figures 3E-1 through 3E-5 along with other piping for which high-energy pipe failures are postulated. These figures also identify piping in the break exclusion zones inside and outside containment. These figures do not include piping of 1 inch size and smaller. Instrumentation and instrumentation lines are not included.

In addition to the high-energy pipe identified in the figures, the hot water heating system (VYS) includes a limited amount of high-energy piping in the auxiliary building. The subject piping is the 3 inch-diameter supply and return header piping for the heating coils in HVAC equipment in the auxiliary building. The hot water heating system lines in the auxiliary building sub-compartments that include seismic category 1 systems or components are restricted to pipe sizes less than or equal to 1 inch NPS. Therefore, there are no postulated pipe breaks in these lines on the nuclear island.

The selection of the failure type is based on whether the system is high or moderate energy during normal operating conditions of the system. High-energy piping includes those systems or portions of systems in which the maximum normal operating temperature exceeds 200°F or the maximum normal operating pressure exceeds 275 psig. Piping systems or portions of systems pressurized above atmospheric pressure during normal plant conditions and not identified as high energy are considered moderate energy. Piping systems that exceed 200°F or 275 psig for 2 percent or less of the time during which the system is in operation or that experience high-energy pressures or temperatures for less than 1 percent of the plant operation time are considered moderate energy. In piping whose nominal diameter is greater than 1 inch but less than 4 inches, only circumferential breaks are postulated at each selected location. No breaks are postulated for piping whose nominal diameter is 1 inch or less.

The three-letter code included in the line numbering identifies the pipe specification. The letters define the pressure class, material specification, and AP1000 equipment classification, respectively. The symbols used in Figures 3E-1 through 3E-5 are the same as the P&ID figures. See Figure 1.7-2 for additional information on the drawing legend and for the key for the pipe specification. Section 3.2 includes additional information on the AP1000 equipment classification.

This page intentionally blank

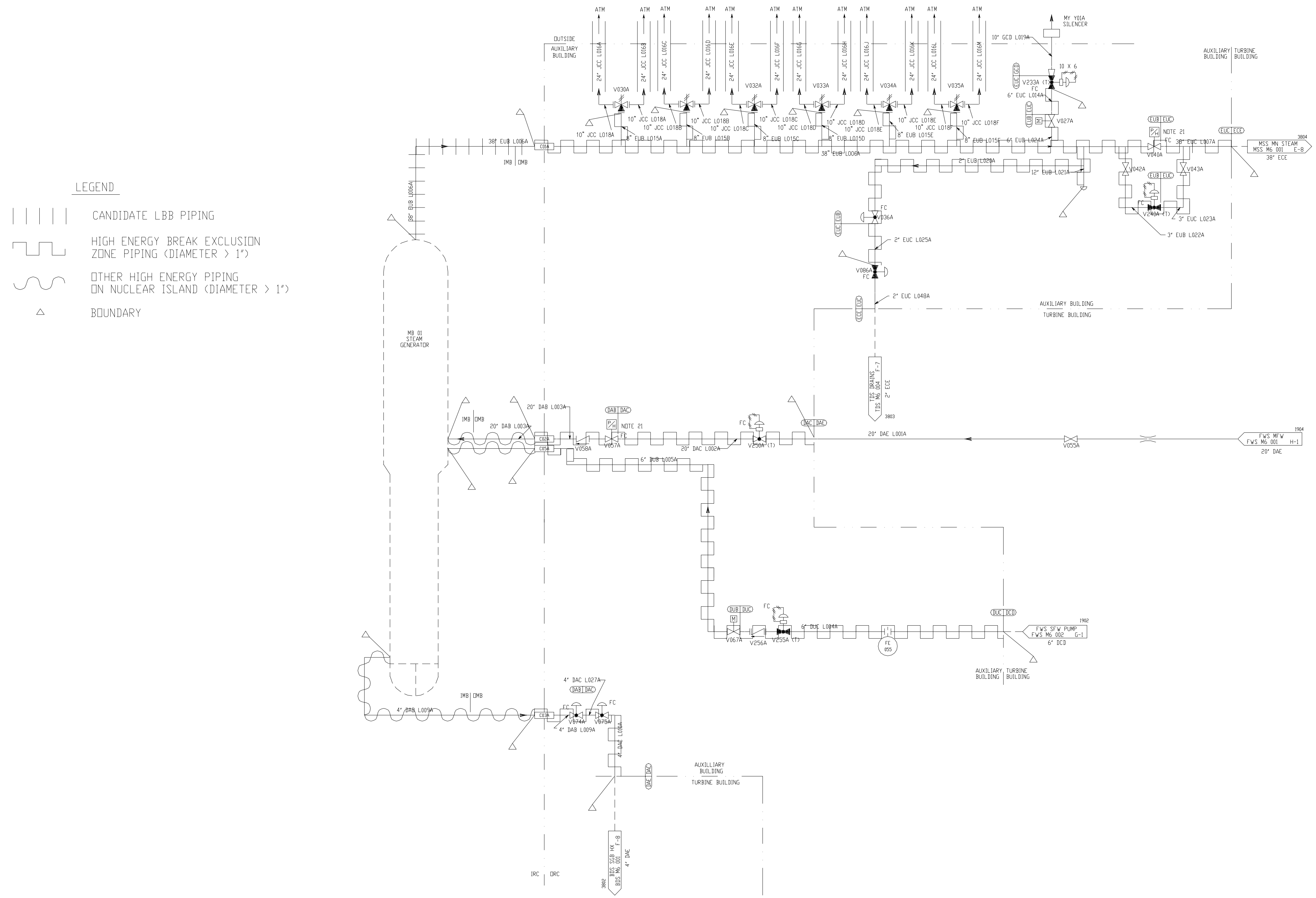


Figure 3E-1 (Sheet 1 of 2)

High Energy Piping – Steam Generator System

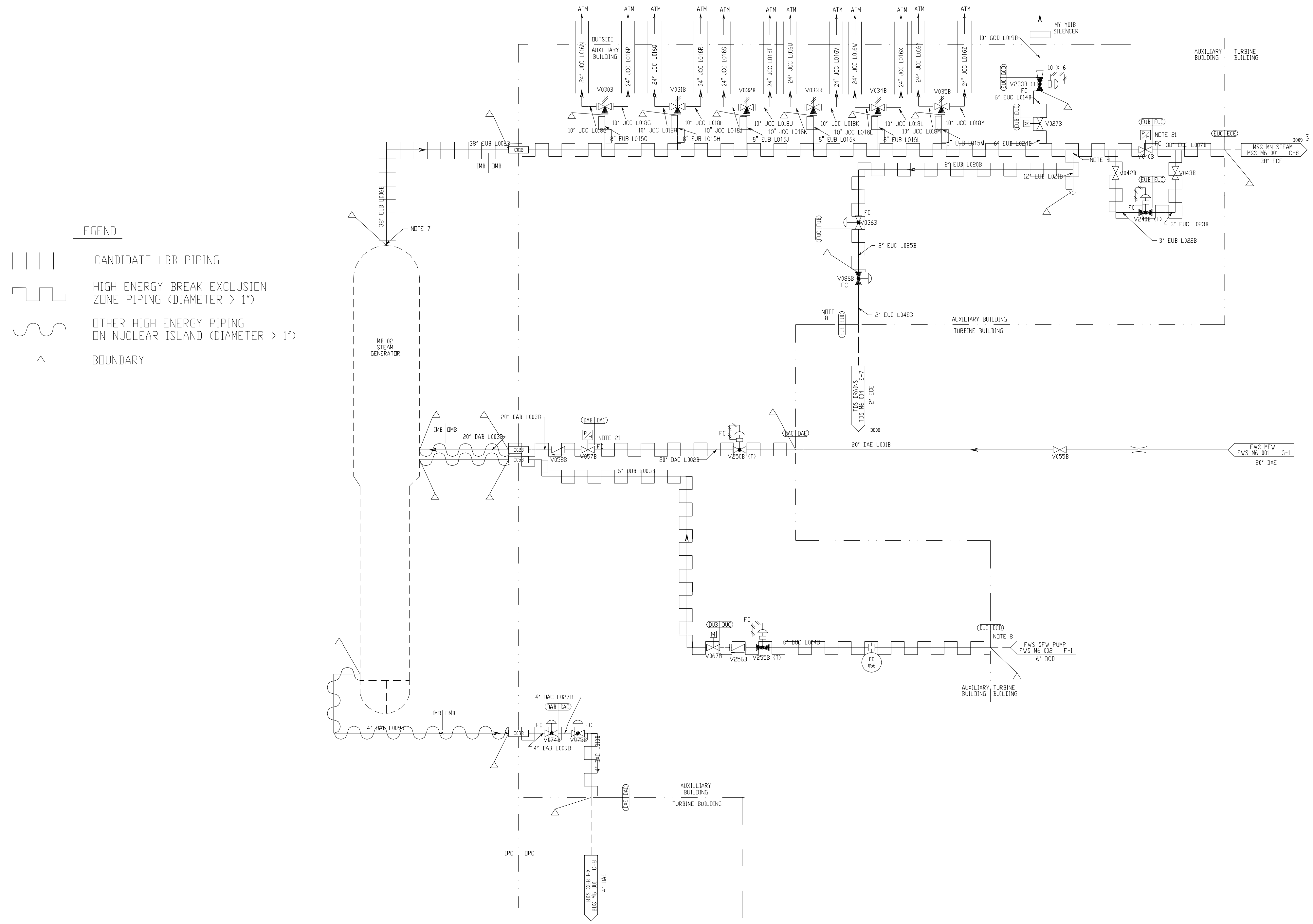


Figure 3E-1 (Sheet 2 of 2)

High Energy Piping – Steam Generator System

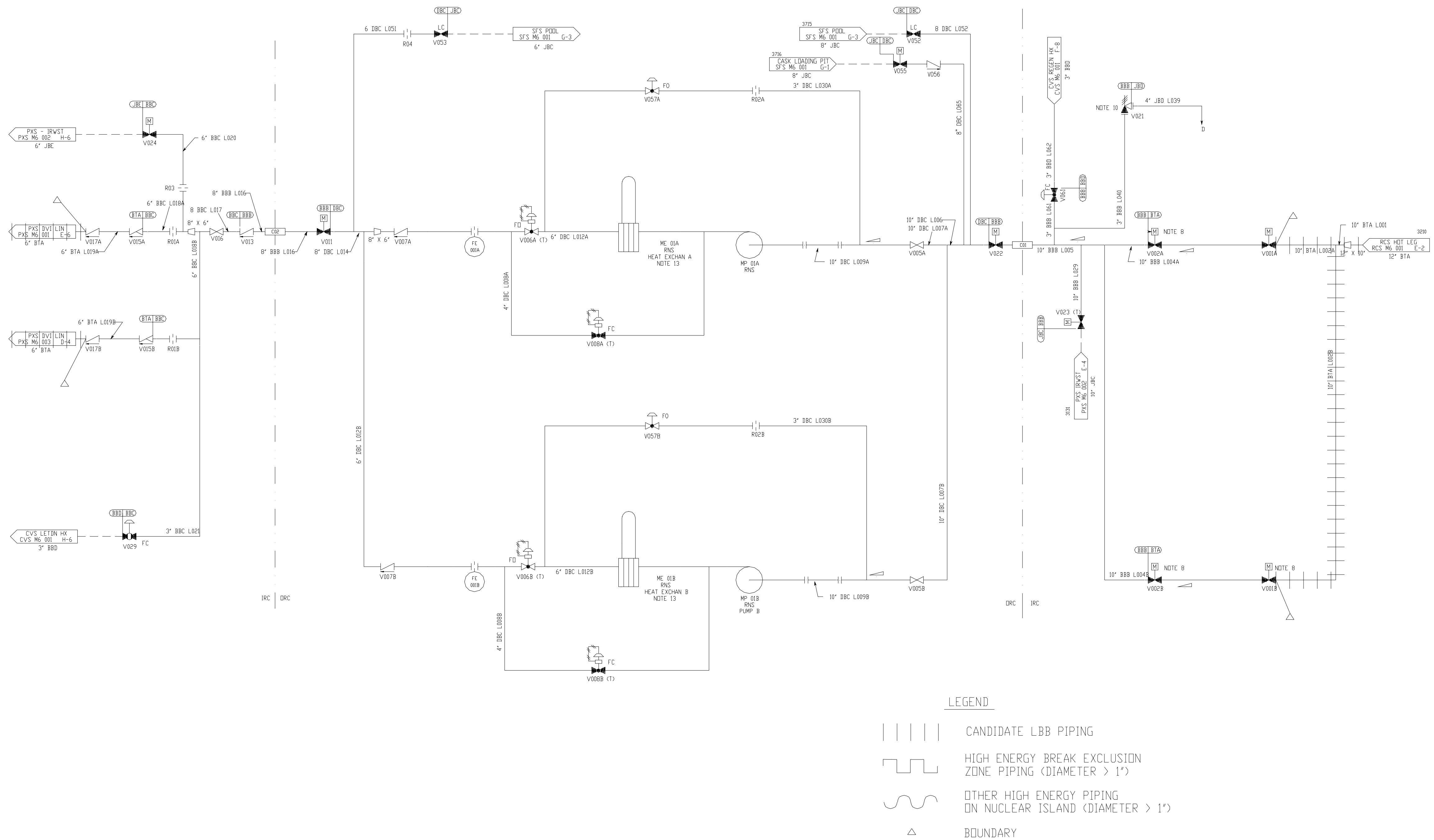


Figure 3E-2

High Energy Piping – Normal Residual Heat Removal System

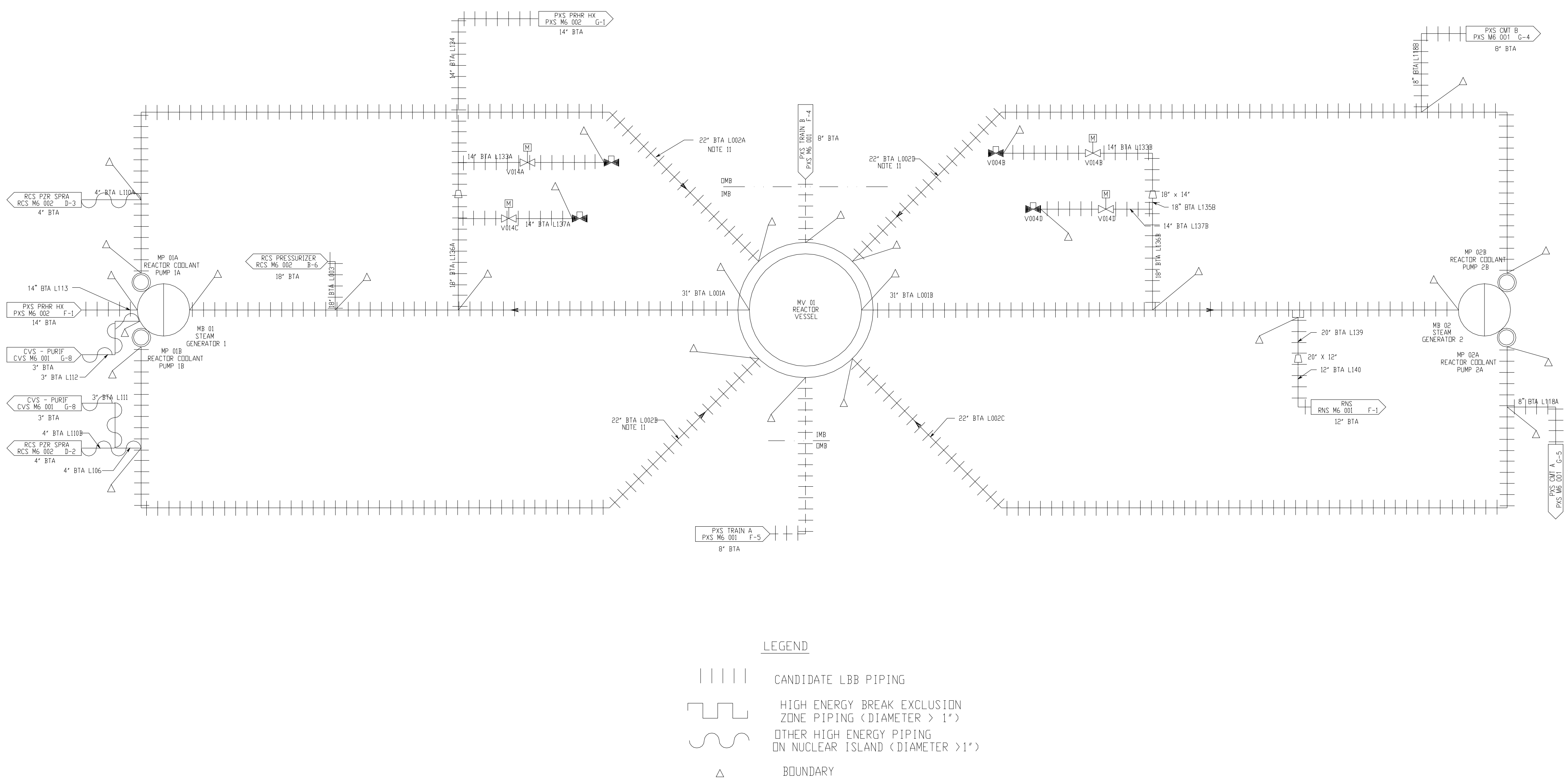


Figure 3E-3 (Sheet 1 of 2)

High Energy Piping – Reactor Coolant System

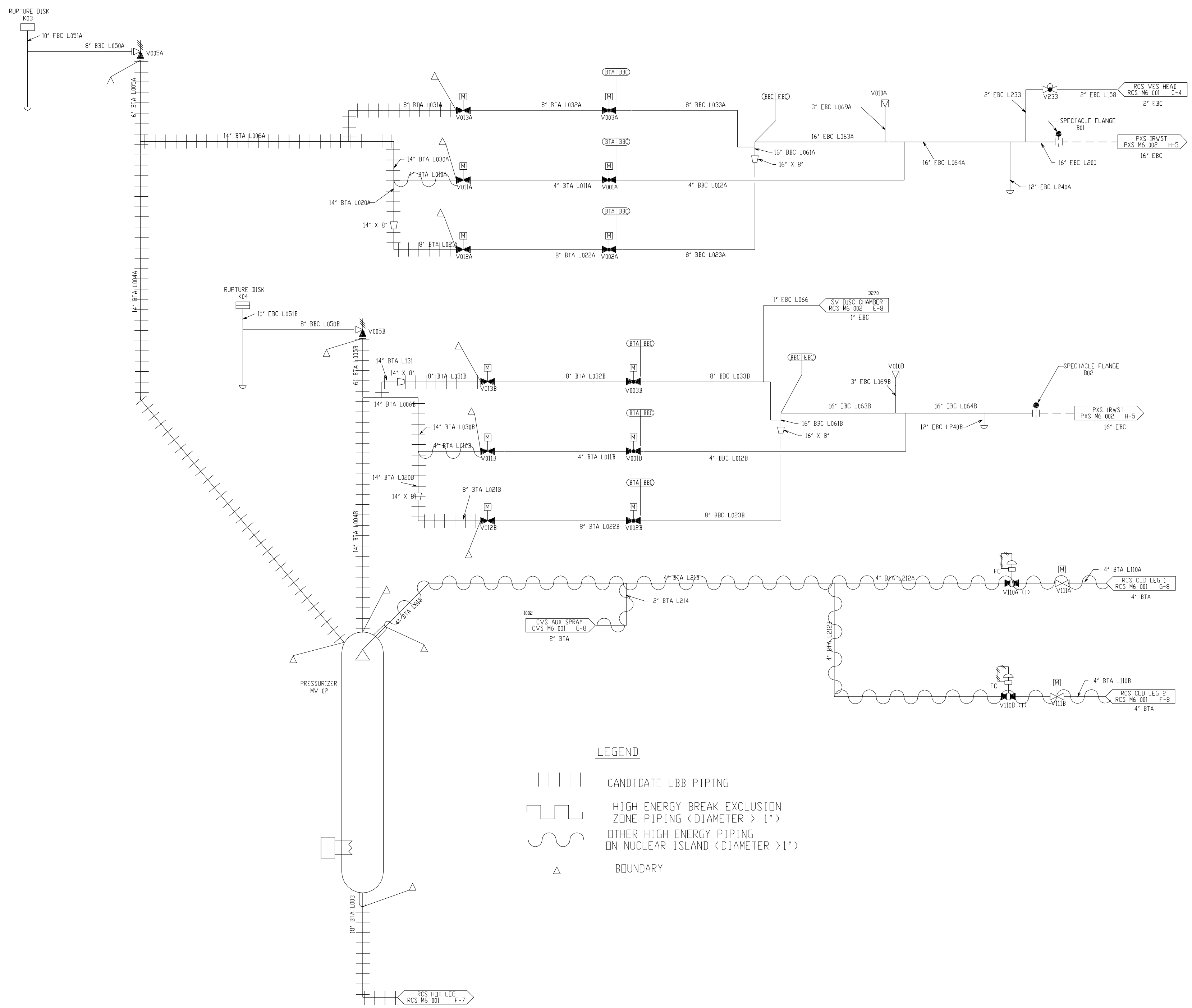


Figure 3E-3 (Sheet 2 of 2)

High Energy Piping – Reactor Coolant System

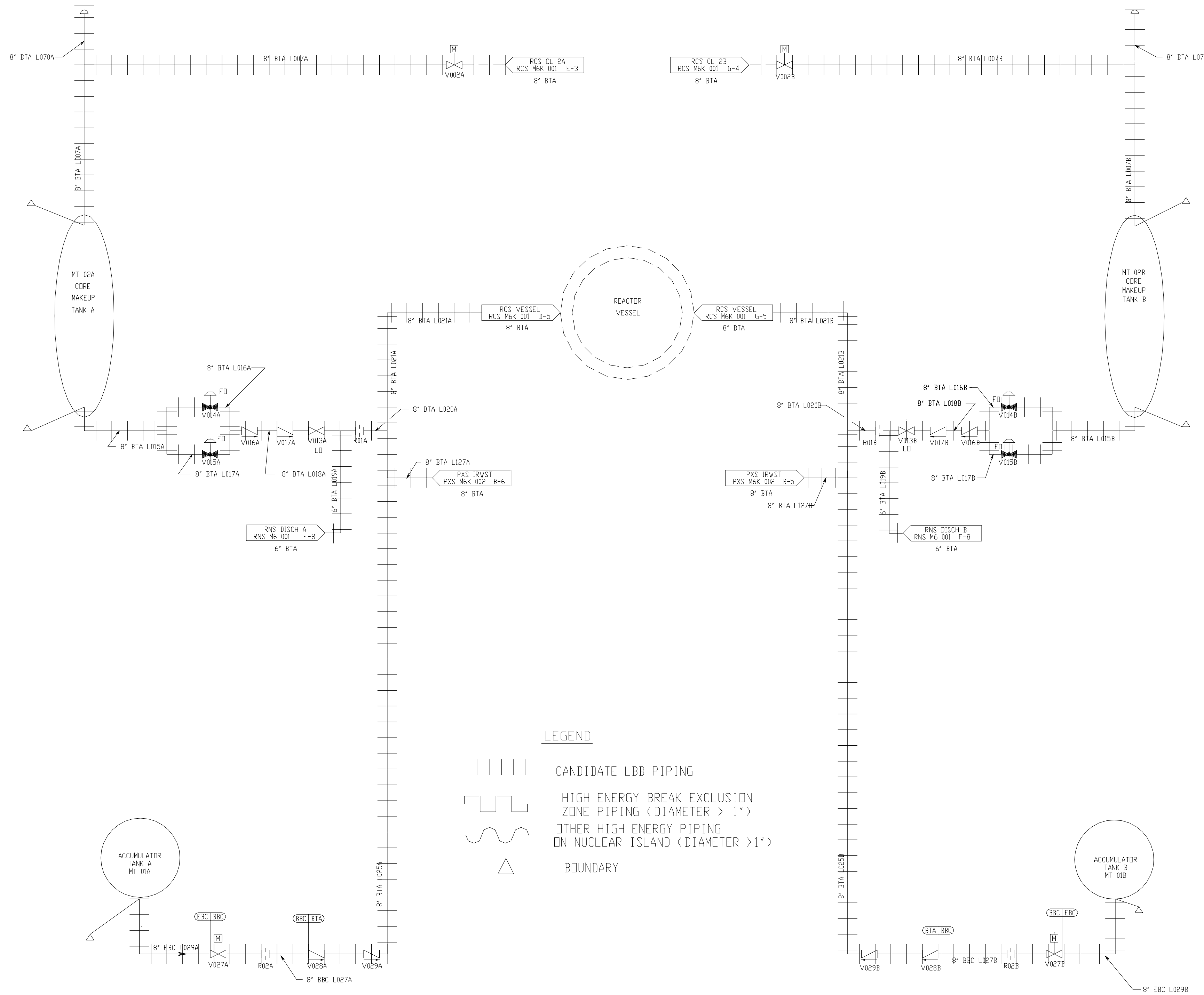


Figure 3E-4 (Sheet 1 of 2)

High Energy Piping – Passive Core Cooling System

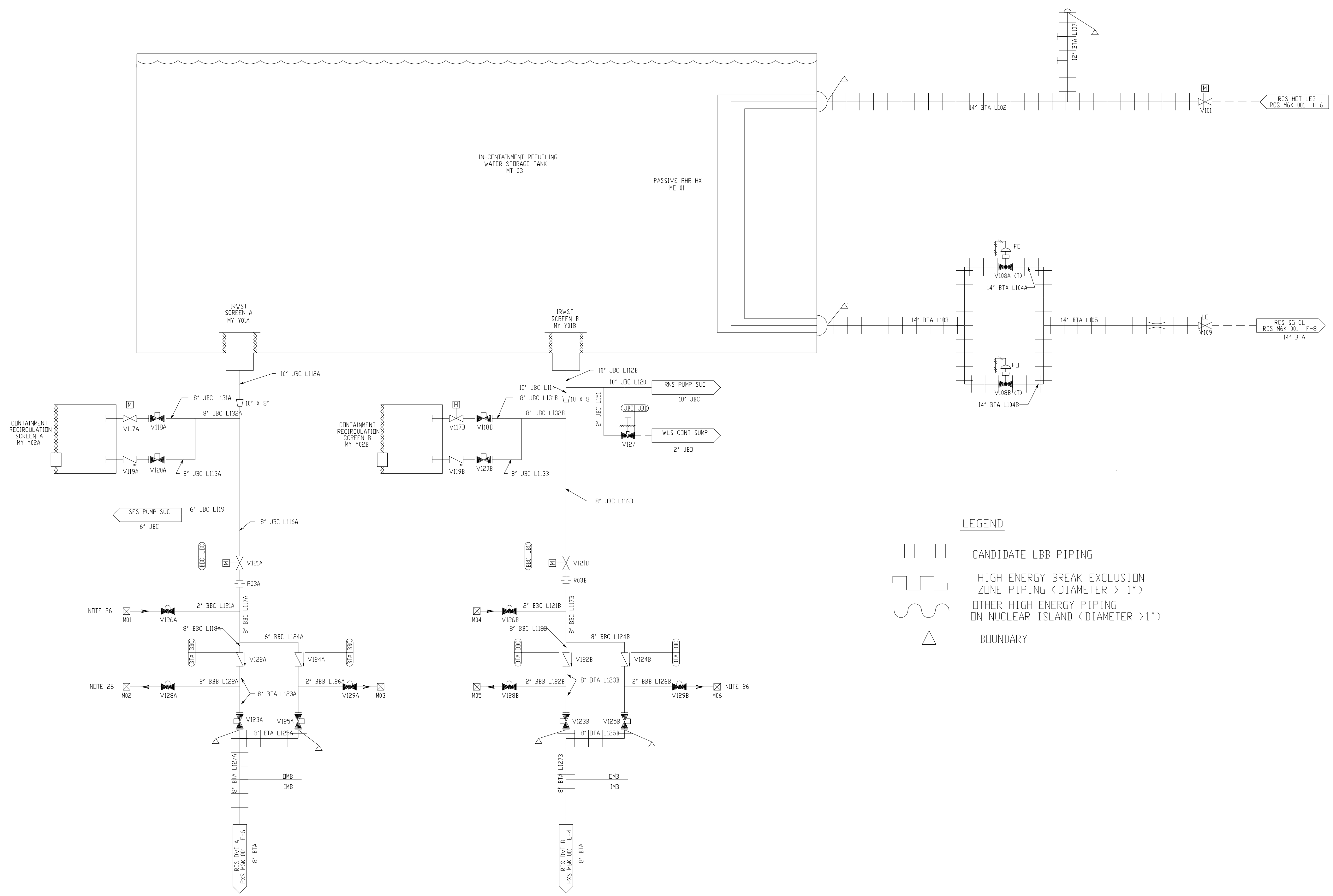


Figure 3E-4 (Sheet 2 of 2)

High Energy Piping – Passive Core Cooling System

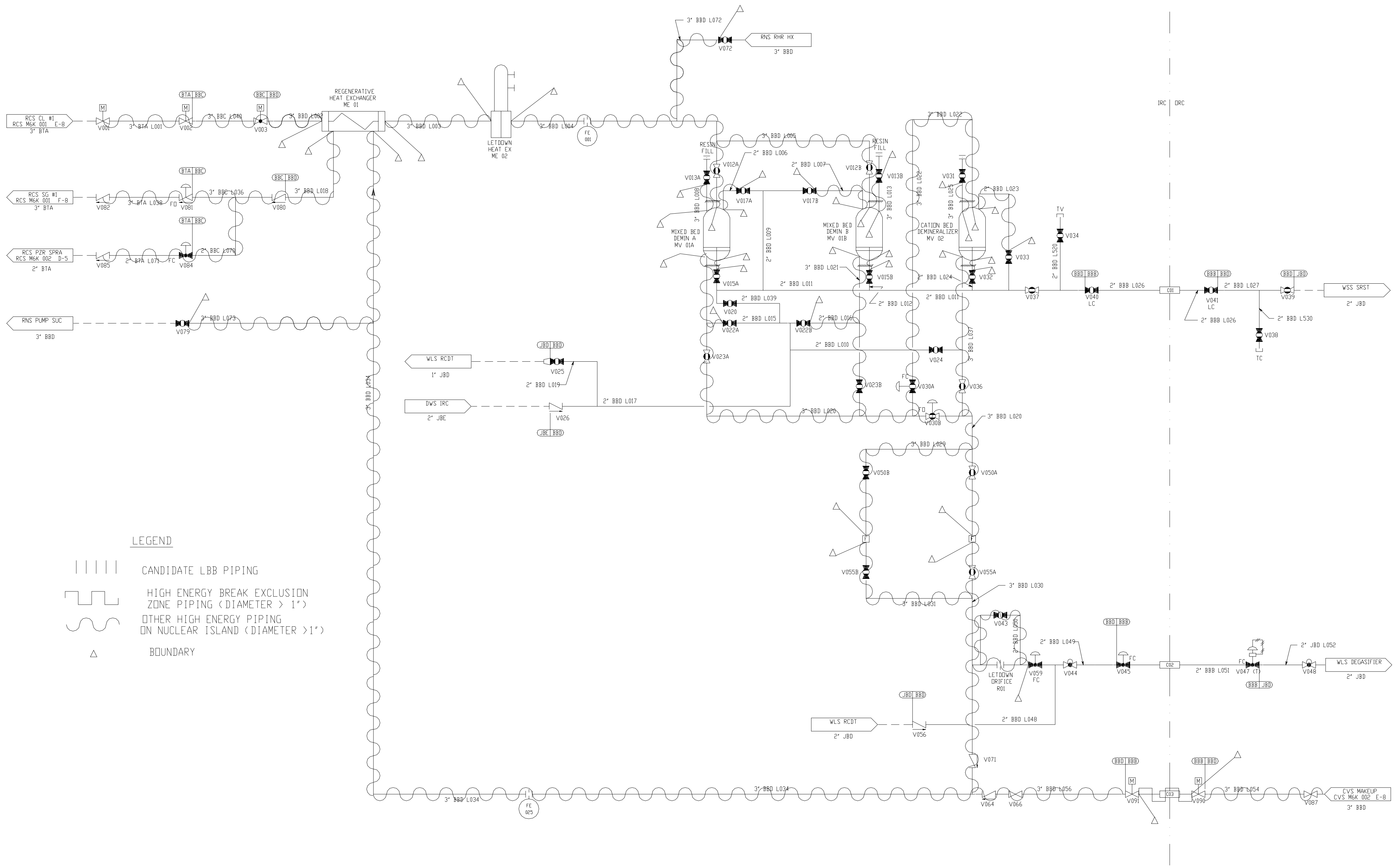


Figure 3E-5 (Sheet 1 of 2)

High Energy Piping – Chemical and Volume Control System

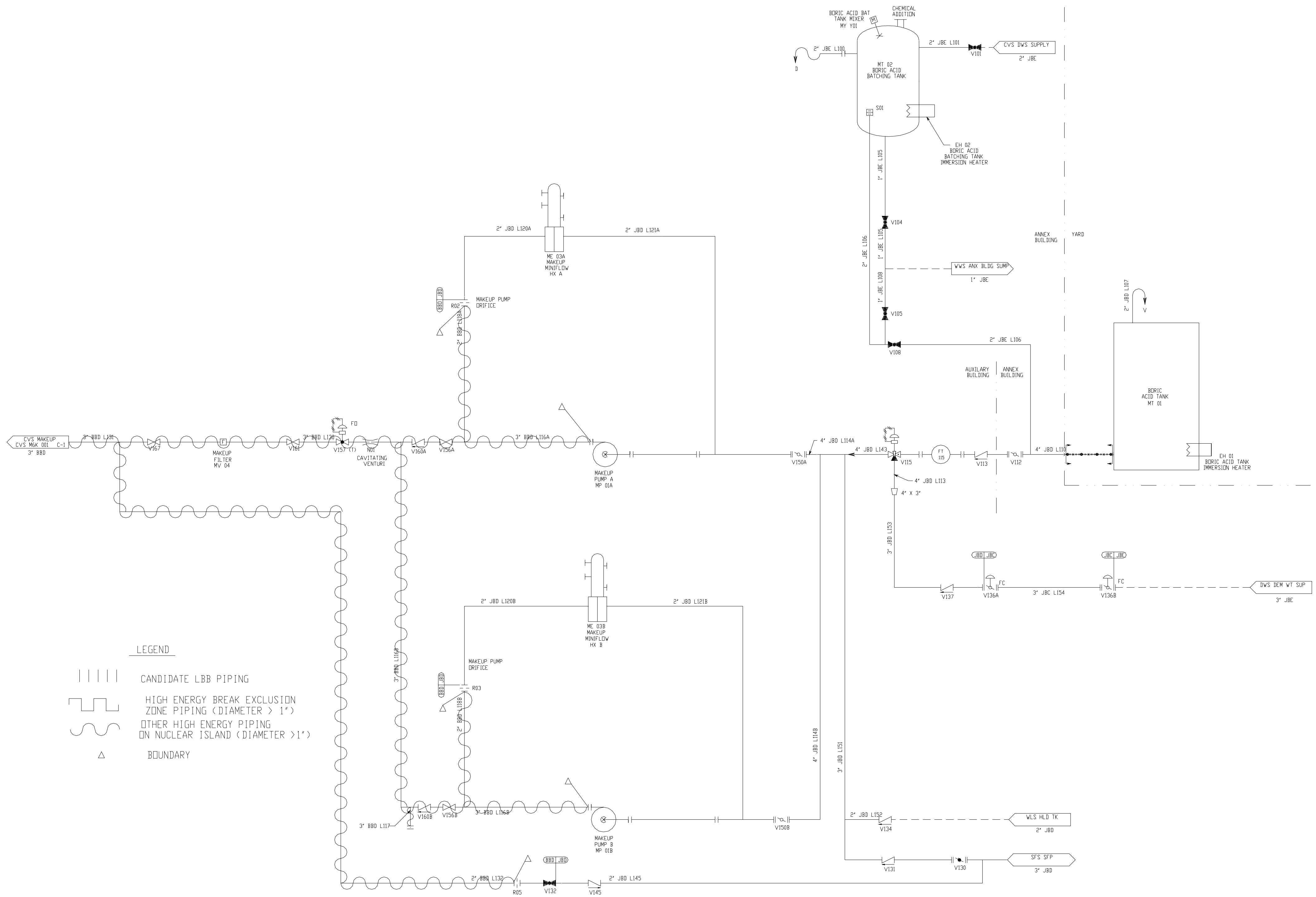


Figure 3E-5 (Sheet 2 of 2)

High Energy Piping – Chemical and Volume Control System

APPENDIX 3F

CABLE TRAYS AND CABLE TRAY SUPPORTS

This appendix provides the design criteria for seismic Category I cable trays and their supports. Seismic Category II cable trays and their supports are also designed utilizing the design criteria of this appendix.

3F.1 Codes and Standards

The design of cable trays and their supports conform to the following codes and standards:

- American Iron and Steel Institute (AISI), Specification for the Design of Cold Formed Steel Structural Members, 1996 Edition and Supplement No. 1, July 30, 1999

- American Institute of Steel Construction (AISC), Specification for the Design, Fabrication and Erection of Steel Safety Related Structures for Nuclear Facilities, AISC-N690-1994

- Institute of Electrical and Electronic Engineers (IEEE), Standard 344-1987, IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations

- National Electrical Manufacturers Association (NEMA), Standard Publication No. VE 1-1998, Metallic Cable Tray Systems

3F.2 Loads and Load Combinations

3F.2.1 Loads

3F.2.1.1 Dead Load (D)

Dead load includes the weight of the cable trays, their supports and the cables inside the trays and any permanently attached items. Temporary items used during construction or maintenance are removed prior to operation.

It also includes the weight of

- Cable tray covers and
- Other components and fittings

3F.2.1.2 Construction Live Load (L)

Live load consists of a load of 250 pounds to be applied only during construction on the tray at a critical location to maximize flexural and shear stresses. This load is not combined with seismic loads.

3F.2.1.3 Safe Shutdown Earthquake (E_s)

Seismic response of the cable trays and their supports are produced due to seismic excitation of the supports.

3F.2.1.4 Thermal Load

These loads are usually not considered and trays are provided with expansion joints in accordance with NEMA.

3F.2.2 Load Combinations

The following load combinations are used for designing the cable trays and their supports:

(a) D + L
(b) D + E_s

3F.3 Analysis and Design

Cable trays and their supports are designed to maintain structural integrity. The stresses are maintained within the allowable limits as specified in subsection 3F.3.3. Section properties and weights of the trays are obtained from manufacturer's data.

3F.3.1 Damping

The maximum damping ratio is 10 percent unless the configuration is demonstrated to be similar to that of the tests described in Reference 19 of subsection 3.7.6.

As stated in subsection 3.7.1.3, the damping ratio used for the AP1000 cable tray systems may be based on test results presented in Reference 19 (subsection 3.7.6). The cable tray test program conducted by ANCO Engineers Inc. included more than 2000 dynamic tests of representative cable tray system design and construction. The test configurations included items such as various tray types on rigid supports, various tray hanger systems, effects of tray types, effects of strut connections and effects of bracing spacing, unbraced and braced tray systems. Cable ties were also used during the test program. Based on observations during the tests, the high damping values within the cable tray system are provided mainly by the movement, sliding or bouncing of the cables within the tray. The tests show that, for unloaded trays, the damping ratio closely approximates the 7 percent used for bolted structures, and a minimum damping value of 20 percent is maintained with cable ties at spacing greater than or equal to four feet. The tests show that for loaded trays, the damping ratio increases with increased cable loading, reaching a value of 30 percent at cable fill ratio of 50 percent to 100 percent. The major factors which affect the damping ratio of the cable tray systems are the input acceleration level, cable fill ratio, and the ability of the cables to move within the trays during a safe shutdown earthquake.

The AP1000 cable tray system design requires no sprayed-on material for fire protection. Cable ties are provided at spacing greater than 4 feet, thereby permitting cable movement within the trays. The damping ratio used for the cable tray system is dependent on the level of seismic input and the amount of cable fill within the trays. As shown in Figure 3.7.1-13, the 20 percent constant

damping ratio may be used for trays loaded to more than 50 percent and subjected to input floor acceleration greater than 0.35g. For cable trays loaded to less than 50 percent and lower than 0.35g input floor acceleration, linearly interpolated lower damping values may be used.

3F.3.2 Seismic Analysis

The methodology for seismic analysis is provided in subsection 3.7.3 Seismic loads are determined by either using the equivalent static load method of analysis or by performing dynamic analysis.

Stresses are determined for the seismic excitation in two horizontal and one vertical direction. The stresses in the three directions are combined using the square root of the sum of the squares (SRSS) method as described in subsection 3.7.2.6.

3F.3.3 Allowable Stresses

The basic stress allowables for the cable trays are based on the American Iron and Steel Institute specification. The basic stress allowables for cable tray supports utilizing light gage cold rolled channel type sections are based on the manufacturer's published catalog values. The basic stress allowables for cable tray supports utilizing rolled structural shapes are in accordance with ANSI/AISC N-690 and the supplemental requirements described in subsection 3.8.4.5.2.

The allowable stresses for the load combinations are as follows:

D + L	Basic Allowable
D + E_s	1.6 times basic allowable for tension and 1.4 times basic allowable for compression

3F.3.4 Connections

Connections are designed in accordance with the applicable codes and standards listed in subsection 3F.1. For connections used with light gage cold rolled channel type sections, design is based on the manufacturer's published catalog values. Supports are attached to the building structure by bolted or welded connections. Fastening of the supports to concrete structures meets the supplemental requirements given in subsection 3.8.4.5.1.

APPENDIX 3G

Appendix 3G not used.

APPENDIX 3H AUXILIARY AND SHIELD BUILDING CRITICAL SECTIONS

3H.1 Introduction

[*This appendix summarizes the structural design and analysis of structures identified as "Critical Sections" in the auxiliary and shield buildings. The design summaries include the following information:*

- *Description of buildings*
- *Governing codes and regulations*
- *Structural loads and load combinations*
- *Global analyses*
- *Structural design of critical structural elements*

Subsections 3H.2 through 3H.4 include a general description of the auxiliary building, a summary of the design criteria and the global analyses. Examples of the structural design are shown for twelve critical sections which are identified in subsection 3H.5 and shown in Figures 3H.5-1 (3 sheets). Representative design details are provided for these structures in subsection 3H.5.]*

3H.2 Description of Auxiliary Building

[*The auxiliary and shield buildings are reinforced concrete structures. The auxiliary building is one of the three buildings that make up the nuclear island and shares a common basemat with the containment building and the shield building. The auxiliary building general layout is shown in Figure 3H.2-1. It is a C-shaped section of the nuclear island that wraps around approximately half of the circumference of the shield building. The building dimensions are shown on key structural dimension drawings, Figure 3.7.2-12.*

The auxiliary building is divided into six areas, which are identified in Figure 3H.2-1. It is a 5-story building; three stories are located above grade and two are located below grade. Areas 1 and 2 (Figure 3H.2-1) have five floors, including two floors below grade level. The lowest floor at elevation 66'-6" is used exclusively for housing battery racks. The next higher floor, at elevation 82'-6", also has battery racks and some electrical equipment. The floor at the grade level, elevation 100'-0", has electrical penetration areas, a remote shutdown workstation room, and some Division A and Division C equipment. The main control room is situated on the floor at elevation 117'-6", which also has rooms for the main steam and feedwater lines. The floor at elevation 135'-3" carries air filtration and air handling units, chiller pumps, and other mechanical and electrical equipment. The roof for areas 1 and 2 is at elevation 153'-0".

Areas 3 and 4 of the auxiliary building are the areas east of the containment shield building. Valve and piping areas, and some mechanical equipment, are located in the basement floor at elevation 66'-6". The floor at elevation 82'-6" has a piping penetration area, a radiation chemistry laboratory, makeup pumps, and other mechanical equipment. The floor at grade level elevation 100'-0" has an electrical penetration room, a staging area for the equipment hatch, and the access opening to the annex building. The electrical penetration area, trip switchgears, and motor control centers occupy most of the floor at elevation 117'-6". The floor at elevation 135'-3"

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

is used for the storage of main control room air cylinders and provides access to the annex building. The roof for these areas is at elevation 160'-6".

Areas 5 and 6 include facilities for storage and handling of new and spent fuel. The spent fuel pool, fuel transfer canal, and cask loading and cask washdown pits have concrete walls and floors. They are lined on the inside surface with stainless steel plate for leak prevention. The walls and major floors are constructed using concrete filled steel plate modules. The new fuel storage area is a separate reinforced concrete pit providing temporary dry storage for the new fuel assemblies. A 150-ton cask handling crane travels in the east-west direction. The location and travel of this crane prevents the crane from carrying loads over the spent fuel pool to preclude them from falling into the spent fuel pool. Mechanical equipment is also located in this area for spent fuel cooling, residual heat removal, and liquid waste processing. This equipment is generally nonsafety-related.

The shield building forms area 7 of the auxiliary building. This appendix describes critical sections in the shield building roof and its connection to the cylindrical wall.]*

3H.3 Design Criteria

[*The auxiliary and shield building structures are reinforced concrete structures, structural modules, and horizontal concrete slabs supported by composite structural steel framing.*

- *Seismic forces are obtained from the equivalent static analysis of the three-dimensional finite element analysis models as described in subsection 3H.4. The shear wall and floor slab design also considers out-of-plane bending and shear forces due to loading, such as live load, dead load, seismic, lateral earth pressure, hydrostatic, hydrodynamic, and wind pressure.*

- *The shield building roof and the passive containment cooling water storage tank are analyzed using three-dimensional finite element models with the ANSYS and GTSTRUDL computer codes]* as described in subsection 3.8.4.4.1. [Loads and load combinations include construction, dead, live, thermal, wind, and seismic. Seismic loads are applied as equivalent static accelerations. The seismic response of the water in the tank is analyzed in a separate finite element response spectrum analysis with seismic input defined by the floor response spectrum.*

- *The structural steel framing is used primarily to support the concrete slabs and roofs. Metal decking, supported by the steel framing, is used as form work for the concrete slabs and roofs.*

- *The finned floors for the main control room and the instrumentation and control room ceilings are designed as reinforced concrete slabs in accordance with American Concrete Institute standard ACI 349. The steel panels are designed and constructed in accordance with American Institute of Steel Construction Standard AISC N690. For positive bending, the steel plate is in tension and the steel plate with fin stiffeners serves as the bottom reinforcement. For negative bending, compression is resisted by the stiffened plate and tension by top reinforcement in the concrete.*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

3H.3.1 Governing Codes and Standards

[*The primary codes and standards used in the design of the auxiliary and shield buildings are listed below:*

- *ACI 349-01, "Code Requirement for Nuclear Safety-Related Structure Steel" (refer to subsection 3.8.4.5 for supplementary requirements)*
- *ANSI/AISC N690-1994, "Specification for the Design, Fabrication and Erection of Safety-Related Steel Structures for Nuclear Facilities" (refer to subsection 3.8.4.5 for supplemental requirements).*]*

3H.3.2 Seismic Input

The SSE design response spectra are given in Figures 3.7.1-1 and 3.7.1-2. [*They are based on the Regulatory Guide 1.60 response spectra anchored to 0.30g, but are amplified at 25 Hertz to reflect larger high-frequency seismic energy content observed for eastern United States sites.*]* The nuclear island seismic analyses are summarized in section 3.7.2.

3H.3.3 Loads

[*The auxiliary and shield buildings are seismic Category I structures. The loads listed in the following subsections are used for the design of the building structures. All the listed loads are not necessarily applicable to all structures and their elements. Loads for which each structural element is designed are based on the conditions to which that particular structural element is potentially subjected.*]*

Dead Load (D):

[*The weight of all permanent construction and installations, including fixed equipment, is included as the dead load during its normal operating condition.*

The weight of minor equipment (not specifically included in the dead load), piping, cables and cable trays, ducts, and their supports was included as equivalent dead load (EDL). A minimum of 50 pounds per square foot (psf) was used as EDL. For floors with a significant number of small pieces of equipment, the total weight of miscellaneous small pieces of equipment, divided by the floor area of the room plus an additional 50 psf was used as the equivalent dead load.]*

Earth Pressure (H):

[*The static earth pressure acting on the structures during normal operation is considered in the design of exterior walls. The dynamic soil pressure, induced during a safe shutdown earthquake (SSE), is included as a seismic load.*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Live Loads (L):

[*The load imposed by the use and occupancy of the building is included as the live load. Live loads include floor area loads, laydown loads, fuel transfer casks, equipment handling loads, trucks, railroad vehicles, and similar items. The floor area live load is not applied on areas occupied by equipment whose weight is specifically included in the dead load. Live load is applicable on areas under equipment where access is provided, for instance, the floor under an elevated tank supported on legs.*

Floor loading diagrams are prepared for areas for component laydown. The diagrams show the location of major pieces of equipment and their foot-print loads or equivalent uniformly distributed loads.

The following live load items are considered in design:

A. Building floor loads

The following minimum values for live loads are used.

– *Structural platforms and gratings*	*100 psf*
– *Ground floors*	*250 psf*
– *All other elevated floors*	*200 psf* *(This load is reduced if the equivalent dead load for the floor is more than 50 psf. The sum of the live load and the equivalent dead load is 250 psf.)*

B. Roof loads

The roof is designed for a uniform snow load of 63 psf calculated in accordance with ASCE 7-98. This corresponds to ground snow load of 75 psf, exposure factor of 1.0, thermal factor of 1.0, and an importance factor of 1.2.

C. Concentrated loads for the design of local members

– *Concentrated load on beams and girders (in load combinations that do not include seismic load)*	*5,000 pounds so applied as to maximize moment or shear. This load is not carried to columns or walls. It is not applied in areas where no heavy equipment will be located or transported, such as the access control areas.*
– *Concentrated load on slabs (considered with dead load only)*	*5,000 pounds so applied as to maximize moment or shear. This load is not carried to columns or walls. It is not applied in access control areas.*

In design reconciliation analysis, if actual loads are established to be lower than the above loads, the actual loads are used for reconciliation.

D. Temporary exterior wall surcharge

When applicable, a minimum surcharge outside and adjacent to subsurface wall of 250 psf is applied.

E. Construction loads

The additional construction loads produced by cranes, trucks, and the like, with their pickup loads, are considered. For steel beams supporting concrete floors, the weight of the wet concrete plus 100 psf uniform load and 5,000 pounds concentrated load, distributed near points of maximum shear and moment, is applied. A one-third increase in allowable stress is permitted.

Metal decking and precast concrete panels, used as formwork for concrete floors are designed for the wet weight of the concrete plus a construction live load of 20 psf uniform or 150 pounds concentrated. The deflection during normal operation is limited to span in inches divided by 180, or 0.75 inch, whichever is less.

F. Crane loads

The impact allowance for traveling crane supports and runway horizontal forces is in accordance with AISC N690.

G. Elevator loads

The impact allowance used for the elevator supports is 100 percent, applied to design capacity and weight of car plus appurtenances, unless otherwise specified by the equipment supplier.

H. Equipment laydown and major maintenance

Floors are designed for planned refueling and maintenance activities as defined on equipment laydown drawings.]*

Wind Load

[*The wind loads are as follows:*

- *Design wind (W)*

  For the design of the exterior walls, wind loads are applied in accordance with ASCE 7-98 with a basic wind speed of 145 mph. The importance factor is 1.15, and the exposure category is C. Wind loads are not combined with seismic loads.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- *Tornado load (W_t)*

  The exterior walls of the auxiliary and shield buildings are designed for tornado. A maximum wind speed of 300 mph (maximum rotational speed: 240 mph, maximum translational speed: 60 mph) is used to design the structures.]*

Seismic Loads (E_s)

[*The SSE (E_s) is used for evaluation of the structures of the auxiliary and shield buildings. E_s is defined as the loads generated by the SSE specified for the plant, including the associated hydrodynamic loads and dynamic incremental soil pressure.*]*

Operating Thermal Loads (T_o)

[*Normal thermal loads for the exterior walls and roofs are addressed in the design. These correspond to positive and negative linear temperature gradients with the inside surface at an average 70°F and the outside air temperature at -40°F and +115°F, respectively. These loads are considered for the seismic Category I structures in combination with the SSE also. All exterior walls of the nuclear island above grade are designed for these thermal loads even if the exterior surface is protected by an adjacent building. The thermal gradient is also applied to the portion of the shield building between the upper annulus and the auxiliary building.*

Normal thermal loads for the passive containment cooling system (PCS) tank design are calculated based on the outside air temperature extremes specified for the safety-related design. With the water temperature in the tank assumed at +40°F, the positive and negative temperature gradients are determined for the outside surface at -40°F and +115°F respectively.

Normal thermal loads due to a thermal gradient in the structures below the grade level (exterior walls and basemat) are small and are not considered in the design.]*

Effects of Pipe Rupture (Y)

[*The evaluations consider the following loads:*

- *Accident design pressure load, P_a, within or across a compartment and/or building generated by the postulated pipe rupture, including the dynamic effects due to the pressure time history.*

  Main steam isolation valve (MSIV) and steam generator blowdown valve compartments are designed for a pressurization load of 6 pounds per square inch (psi).

- *Accident thermal loads, T_a, due to thermal conditions generated by the postulated pipe break and including T_o.*

Temperature gradients are based on an exterior air temperature of -40°F.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

The structural integrity of the west wall of the main control room is also evaluated for the jet impingement (Y_j)]*

3H.3.4 Load Combinations and Acceptance Criteria

[*Concrete structures are designed in accordance with ACI 349 for the load combinations and load factors given in Table 3.8.4-2. Steel structures are designed in accordance with AISC N690 for the load combinations and stress limit coefficients given in Table 3.8.4-1. The following supplemental requirements are applied for the use of AISC N690:*

- *In Section Q1.0.2, the definition of secondary stress applies to stresses developed by temperature loading only.*
- *In Section Q1.3, where the structural effects of differential settlement are present, they are included with the dead load, D.*
- *In Table Q1.5.7.1, the stress limit coefficients for compression are as follows:*
  - *1.3 instead of 1.5 in load combinations 2, 5, and 6*
  - *1.4 instead of 1.6 in load combinations 7, 8, and 9*
  - *1.6 instead of 1.7 in load combination 11*
- *In Section Q1.5.8, for constrained members (rotation and/or displacement constraint such that a thermal load causes significant stresses) supporting safety-related structures, systems, or components, the stresses under load combinations 9, 10, and 11 are limited to those allowed in Table Q1.5.7.1 as modified above.*]*

3H.4 Seismic Analyses

[*A global seismic analysis of the AP1000 nuclear island structure is performed to obtain building seismic response for the seismic design of nuclear safety-related structures. The seismic loads for the design of the shear walls and the slabs in the auxiliary building are based on an equivalent static analysis of the auxiliary building and the shield building 3D finite element models.*]* This analysis is described in subsection 3.7.2. [*For determining the out-of-plane seismic loads on flexible slabs and wall segments, spectral accelerations are obtained from time history analyses or from the relevant response spectra, using the 7 percent damping curve. Hand calculations are performed to estimate the out-of-plane seismic forces and the corresponding bending moment in each shear wall and floor slab element to supplement the loads obtained from the global seismic analysis.*

3H.4.1 Live Load for Seismic Design

[*Floor live loads, based on requirements during plant construction and maintenance activities, are specified varying from 50 to 250 pounds per square foot.*

For the local design of members, such as the floors and beams, seismic loads include the response due to masses equal to 25 percent of the specified floor live loads or 75 percent of the roof snow load, whichever is applicable. These seismic loads are combined with 100 percent of

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

the specified live loads, or 75 percent of the roof snow load, whichever is applicable. These live and snow loads are included as mass in calculating the vertical seismic forces on the floors and roof. The mass of equipment and distributed systems is included in both the dead and seismic loads.]*

3H.5 Structural Design of Critical Sections

[*This subsection summarizes the structural design of representative seismic Category I structural elements in the auxiliary building and shield building. These structures are listed below and the corresponding location numbers are shown on Figure 3H.5-1. The basis for their selection to this list is also provided for each structure.*

(1) South wall of auxiliary building (column line 1), elevation 66'-6" to elevation 180'-0". (This exterior wall illustrates typical loads such as soil pressure, surcharge, temperature gradients, seismic, and tornado.) – see subsection 3H.5.1.1 and Figures 3H.5-2 and 3H.5-3

(2) Interior wall of auxiliary building (column line 7.3), elevation 66'-6" to elevation 160'-6" (This is one of the most highly stressed shear walls.) – see subsection 3H.5.1.2 and Figure 3H.5-4

(3) West wall of main control room in auxiliary building (column line L), elevation 117'-6" to elevation 153'-0". (This illustrates design of a wall for subcompartment pressurization.) – see subsection 3H.5.1.3 and Figure 3H.5-12

(4) North wall of MSIV east compartment (column line 11), elevation 117'-6" to elevation 153'-0". (The main steam line is anchored to this wall segment.) – see subsection 3H.5.1.4 and Figure 3H.5-5

(5) Shield building cylinder, elevation 160'-6" to elevation 200'-0". (This includes the connection of the roof slab at elevation 180'-0" in (6) below.) – see subsection 3H.5.1.5 and Figure 3H.5-7

(6) Roof slab at elevation 180'-0" adjacent to shield building cylinder. (This is the connection between the two buildings at the highest elevation.) – see subsection 3H.5.2.1 and Figure 3.H.5-7

(7) Floor slab on metal decking at elevation 135'-3". (This is a typical slab on metal decking and structural steel framing.) – see subsection 3H.5.2.2 and Figure 3H.5-6

(8) 2'-0" slab in auxiliary building (tagging room ceiling) at elevation 135'-3". (This illustrates the design of a typical 2'-0" thick concrete slab.) – see subsection 3H.5.3.1 and Figure 3H.5-8

(9) Finned floor in the main control room at elevation 135'-3". (This illustrates the design of the finned floors.) – see subsection 3H.5.4 and Figure 3H.5-9

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

(10) *Shield building roof/PCCS water storage tank. (This is a unique area of the roof and water tank.) – see subsection 3H.5.6.3 and Figure 3H.5-11, sheet 8*

(11) *Shield building roof to cylinder location at columns. (This is the junction between the shield building roof and the cylindrical wall of the shield building.) – see subsections 3H.5.6.1 and 3H.5.6.2 and Figure 3H.5-11*

(12) *Divider wall between the spent fuel pool and the fuel transfer canal. (This wall is subjected to thermal and seismic sloshing loads.) – see subsection 3H.5.5.1 and Figure 3H.5-10*]*

3H.5.1 Shear Walls

Structural Description

[*Shear walls in the auxiliary building vary in size, configuration, aspect ratio, and amount of reinforcement. The stress levels in shear walls depend on these parameters and the seismic acceleration level. The range of these parameters and the stress levels in various regions of the most severely stressed shear wall are described in the following paragraphs.*

The height of the major structural shear walls in the auxiliary building ranges between 30 to 120 feet. The length ranges between 40 and 260 feet. The aspect ratio of these walls (full height/full length) is generally less than 1.0 and often less than 0.25. The walls are typically 2 to 5 feet thick, and are monolithically cast with the concrete floor slabs, which are 9 inches to 2 feet thick. Exterior shear walls are several stories high and do not have many large openings. Interior shear walls, however, are discontinuous in both vertical and horizontal directions. The in-plane behavior of these shear walls, including the large openings, is adequately represented in the analytical models for the global seismic response. Where the refinement of these finite element models is insufficient for design of the reinforcement, for example in walls with a large number of openings, detailed finite element models are used.

The shear walls are used as the primary system for resisting the lateral loads, such as earthquakes. The auxiliary building shear walls are also evaluated for flexure and shear due to the out-of-plane loads.]*

Design Approach

[*The auxiliary building shear walls are designed to withstand the loads specified in subsection 3H.3.3. Beside dead, live, and other normal operating condition loads, the following loads are considered in the shear wall design:*

- *Seismic loads*
  - *The SSE loads for the wall are obtained from the seismic analyses of auxiliary/shield buildings that are described in subsection 3H.4.*
  - *Calculations are performed by considering shear wall segments bounded by the floors below and above the segment and the adjacent walls perpendicular to, on both sides of, the segment under consideration. Appropriate boundary conditions are assumed for the*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

four edges of the segment. Natural frequency of wall segments are determined using finite element models or text book formulas for the frequency of plate structures. Corresponding spectral acceleration is determined from the applicable response spectrum.

- *Exterior walls, below grade level, are also evaluated for dynamic earth pressure exerted during an SSE for two cases:*

  - *Dynamic earth pressure calculated in accordance with ASCE 4-98*
  - *Passive earth pressure*

- *Accident pressure load*

  - *Shear walls of the main steam isolation valves (MSIV) rooms are designed for 6 pounds per square inch (psi) differential pressure acting in conjunction with the seismic loads. Member forces due to accident pressure and SSE are combined by absolute sum.*

  - *The main control room wall of the east MSIV compartment is evaluated for the pressure and the jet load due to a postulated main steamline break.*

- *Tornado load*

  For exterior walls above grade level, tornado loads are considered.

The design temperatures for thermal gradient are included in Table 3H.5-1.

The shear walls are designed for the load combinations, as applicable, contained in Table 3.8.4-2. The wall sections are designed in accordance with the requirements of ACI 349-01.]*

3H.5.1.1 Exterior Wall at Column Line 1

[*The wall at column line 1 is the exterior wall at the south end of the nuclear island. The reinforced concrete wall extends from the top of the basemat at elevation 66'-6" to the roof at elevation 180'-0". It is 3'-0" thick below the grade and 2'-3" thick above the grade.*

The wall is designed for the applicable loads including dead load, live load, hydrostatic load, static and dynamic lateral soil pressure loads, seismic loads, and thermal loads. As shown in Figure 3H.5-2, the wall is divided in 12 segments for design purpose. Table 3H.5-2 provides the listing and magnitude of the various design loads. Table 3H.5-3 presents the governing load combination for each wall segment and the details of the wall reinforcement. The actual reinforcement provided is compared to the required rebar area for each wall segment. Figure 3H.5-3 shows the typical reinforcement for the wall at column line 1.]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

3H.5.1.2 Wall at Column Line 7.3

[*The wall at column line 7.3 is a shear wall that connects the shield building and the nuclear island exterior wall at column line I. It extends from the top of the basemat at elevation 66'-6" to the top of the roof. The wall is 3 feet thick below the grade at elevation 100'-0" and 2 feet thick above the grade. Out-of-plane lateral support is provided to the wall by the floor slabs on either side of it and the roof at the top.*

Wall 7.3 is designed for the applicable loads described in subsection 3H.3.3.

For various segments of this wall, the corresponding governing load combination and associated design loads are shown in Table 3H.5-4.

Table 3H.5-5 presents the details of the wall reinforcement. The actual reinforcement provided is compared to the required reinforcement area for each wall segment. Typical wall reinforcement is also shown on Figure 3H.5-4]*

3H.5.1.3 Wall at Column Line L

[*The wall at column line L is a shear wall on the west side of the Main Control Room. It extends from the top of the basemat at elevation 66'-6" to the top of the roof. The wall is 2 feet thick. Out-of-plane lateral support is provided to the wall by the floor slabs on either side of it and the roof at the top. The segment of the wall that is a part of the main control room boundary is from elevation 117'-6" to elevation 135'-3".*

The auxiliary building design loads are described in subsection 3H.3.3, and the wall is designed for the applicable loads. In addition to the dead, live and seismic loads, the wall is designed to withstand a 6 pounds per square inch pressure load due to a pipe break in the MSIV room even though it is a break exclusion area. This wall segment is also designed to withstand a jet load due to the pipe break.

The governing load combination and associated design loads are those due to the postulated pipe rupture and are shown in Table 3H.5-6.

Table 3H.5-7 and Figure 3H.5-12 present the details of the wall reinforcement. The actual reinforcement provided is compared to the required reinforcement area for each wall segment.]*

3H.5.1.4 Wall at Column Line 11

[*The north wall of the MSIV east compartment, at column line 11 between elevation 117'-6" and elevation 153'-0", has been identified as a critical section.*

The segment of the wall between elevation 117'-6" and elevation 135'-3" is 4 feet thick, and several pipes such as the main steam line, main feed water line, and the start-up feed water line are anchored to this wall at the interface with the turbine building.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

The wall segment from elevation 135'-3" to elevation 153'-0" does not provide support to any high energy lines, and is 2 feet thick. This portion does not have to withstand reactions from high energy line breaks.

The wall is designed to withstand loads such as the dead load, live load, seismic load and the thermal load. The MSIV room is a break exclusion area, but the design also considered the loads associated with pipe rupture in the MSIV room, such as compartment pressurization, jet load, and the reactions at the pipe anchors. The loads on the pipe anchor include pipe rupture loads for breaks in the turbine building.

The wall structure is analyzed using three dimensional finite element analyses supplemented by hand calculations. Analyses are performed for individual loads, and design loads are determined for applicable load combinations from Table 3.8.4-2.

Typical wall reinforcement is shown in Figure 3H.5-5.]*

3H.5.1.5 Shield Building Cylinder at Elevation 180′-0″

[*The thickness of the cylindrical portion of the shield building wall is 3 feet.*

The wall is designed for the applicable loads described in subsection 3H.3-3. A detailed finite element analysis is performed to determine the design forces. The amount of reinforcement in horizontal and vertical directions provided on each face is the same. Typical reinforcement from elevation 200'-0" to 160'-6", above the auxiliary building roof, on each face, is shown in Figure 3H.5-7.

The reinforcement is shown on Figure 3H.5-7. The design of the shield building roof is described in 3H.5.6.]*

3H.5.2 Composite Structures (Floors and Roof)

[*The floors consist of a concrete slab on metal deck, which rests on structural steel floor beams. Several floors in the auxiliary building are designed as one-way reinforced concrete slabs supported continuously on steel beams. Typically, the beams span between two reinforced concrete walls. The beams are designed as composite with formed metal deck spanning perpendicular to the members. Unshored construction is used. For the floors, beams are typically spaced at about 6-feet intervals and spans are between 16 feet and 25 feet.*]*

Structural Description

[*A typical layout of these floors is shown in Figure 3H.5-6. The metal deck rests on the top flange of the structural steel floor beam, with the longitudinal axes of the metal deck ribs and floor beams placed perpendicular to each other. The depth of the ribs for 9-inch concrete floor slabs and 15-inch deep concrete roof slabs are 3 inches and 4.5 inches respectively. The concrete slab is tied to the structural steel floor beam by shear connectors, which are welded to the top flange of the floor beam. The concrete slab and the floor beams form a composite floor system. For the design loads after hardening of concrete, the transformed section is used to check the stresses.*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

The construction sequence is as follows:

- *The structural steel floor (floor beam, metal deck, and shear connectors) is fabricated in the shop, brought to the floor location, and placed in position. In some cases, the beams and deck are preassembled and placed as a module.*

- *The metal deck is used as the formwork, and concrete is poured on the metal deck. Until concrete hardens, the load is carried by the metal deck and the steel floor beam.*

- *During concreting, no shoring is provided.*]*

Design Approach

[*The floor design considers the dead, live, construction, extreme environmental, and other applicable loads identified in Section 3H.3.3. The design floor loading includes the equipment attached to the floor. The end condition for the steel beams is simply supported, or continuous. The seismic load is obtained using the applicable floor acceleration response spectrum (7 percent damping for the SSE loads).*

The load combinations applicable to the design of these floors are shown in Tables 3.8.4-1 and 3.8.4-2. The design of the floor system is performed in two parts:

- *Design of structural steel beams*
  - *The structural steel floor beams are evaluated to withstand the weight of wet concrete during the placement of concrete. The composite section is checked for the design loads during normal and extreme environment conditions. Shear connectors are also designed.*

- *Design of concrete slab*
  - *The concrete slab and the steel reinforcement of the composite section are evaluated for normal and extreme environmental conditions. The slab concrete and the reinforcement is designed to meet the requirements of American Concrete Institute standard ACI 349-01 "Code Requirements for Nuclear Safety-Related Structures."*
  - *The slab design considers the in-plane and out-of-plane seismic forces. The global in-plane and out-of-plane forces are obtained from the equivalent static analysis of the 3D finite element model of the auxiliary and shield buildings. The out-of plane seismic forces due to floor self-excitation are determined by hand calculations using the applicable vertical seismic response spectrum and slab frequency.*]*

3H.5.2.1 Roof at Elevation 180′-0″, Area 6 (Critical Section is between Col. Lines N & K-2 and 3 & 4)

[*The layout of this segment of the roof is shown in Figure 3H.5-7 as Region "B." The concrete slab is 15 inches thick, plus 4.5-inch deep metal deck ribs. It is composite with 5 feet deep plate girders, spaced 14'-2" center to center, by using shear connectors. The girder flanges are 20" x 2" and the web is 56" x 7/16". The girders span approximately 64 feet in the north-south*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

direction and are designed as simply supported. The concrete slab between the girders behaves as a one-way slab and is designed to span between the girders.

The roof girders are designed for dead and live loads, including construction loads (with wet concrete) with simple support end conditions. A one-third increase in allowable stress is permitted for the construction load combination.

The girders are also evaluated as part of the composite beam after drying of concrete. The composite roof structure is designed to withstand dead and live load / snow load, as well as the wind, tornado and seismic loads.

A typical connection of the roof slab to the shield building is shown in Figure 3H.5-7. The figure shows the arrangement of reinforcement at the connection in the fuel building roof, the shield building cylindrical wall, and the walls of the auxiliary building just below the roof. The design summary is shown in Table 3.H.5-10.]*

3H.5.2.2 Floor at Elevation 135′-3″, Area 1 (Between Column Lines M and P)

[*The design of a typical composite floor is shown in Figure 3H.5-6. The design summary is shown in Table 3.H.5-11. The concrete slab is 9 inches thick, plus 3-inch deep metal deck ribs. The floor beams are typically W14x26.*

- *The floor beams are designed for construction load (with wet concrete) with simple support end conditions. The design loads include the dead load and a construction live load of 100 pounds per square foot (psf) distributed load plus 5000 pounds concentrated load near the point of maximum shear and moment. A one-third increase in allowable stress is permitted.*

- *The floor beams are also evaluated as part of the composite beam after drying of the concrete. Because of continuity of rebars into the wall and the connection of the bottom flange to the support embedment, the end support condition is considered as fixed.*]*

3H.5.3 Reinforced Concrete Slabs

[*Reinforced concrete floors in auxiliary building are 24 inch or 36 inch thick. These floors are constructed with 16" or 28" of reinforced concrete placed on the top of 8 inch thick precast concrete panels. The 8" thick precast concrete panels are installed at the bottom to serve as the formwork and withstand the load of wet concrete slab. The main reinforcement is provided in the precast panels which are connected to the concrete placed above it by shear reinforcement. The precast panels and the cast-in-place concrete act together as a composite reinforced concrete slab. Examples of such floors are the Tagging Room ceiling slab at elevation 135 ft 3 inches in Area 2, and the Area 5/6 elevation 100'-0" slab between column lines 1 & 2.*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

3H.5.3.1 Tagging Room Ceiling

The tagging room (room number 12401) location is shown on Figure 1.2-8. [*Figure 3H.5-8 shows the typical cross section and reinforcement. The design summary is shown in Table 3.H.5-12. Design dimensions of the Tagging Room Ceiling are as follows:*

Room Size:	*16'-0" x 11'-10"*
Boundary Conditions:	*Fixed at Walls J and K*
Clear Span:	*16'-0"*
Slab Thickness:	*Total = 24 inches* *Precast Panel = 8 inches* *Cast-in-Place = 16 inches*

*The two precast concrete panels, each 5'-11" wide and spanning over 16'-0" clear span, are installed to serve as the formwork.]**

3H.5.4 Concrete Finned Floors

[*The ceilings of the main control room, and the instrumentation and control rooms in the auxiliary building are designed as finned-floor modules. A typical floor design is shown in Figure 3H.5-9. A finned floor consists of a 24-inch-thick concrete slab poured over a stiffened steel plate ceiling. The fins, welded to stiffen the steel plate, are half inch by 9 inch rectangular sections perpendicular to the plate. Shear studs are welded on the other side of the steel plate, and the steel and concrete act as a composite section. The fins are exposed to the environment of the room and enhance the heat-absorbing capacity of the ceiling. Several shop-fabricated steel panels, cut to room width and placed side by side perpendicular to the room length, are used to construct the stiffened plate ceiling in a modularized fashion. The stiffened plate with fins is designed to withstand construction loads prior to concrete hardening.*

The main control room ceiling fin floor is designed for the dead, live, and the seismic loads. The design summary is shown in Table 3.H.5-13.

The finned floor structure is evaluated for the load combinations listed in Tables 3.8.4-1 and 3.8.4-2.]*

Design Methodology

[*The finned floors are designed as reinforced concrete slabs in accordance with ACI Standard 349. For positive bending, the steel plate is in tension. The steel plate with fin stiffeners serves the function of bottom rebars. For negative bending, the potential for buckling due to compression in this element is checked by using the criteria of American National Standards Institute/American Institute of Steel Construction standards ANSI/AISC N690-94. Twisting, and therefore lateral buckling of the stiffener, is restrained by the concrete.*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

The finned floors resist vertical and in-plane forces for both normal and extreme loading conditions. For positive bending, the concrete above the neutral axis carries compressive stresses and the stiffened steel plate resists tension. Negative bending compression is resisted by the stiffened plate and tension by top rebars in the concrete. The neutral axis for negative bending is located in the stiffened plate section, and the concrete in tension is assumed inactive. Horizontal in-plane forces are resisted by the stiffened plate and longitudinal rebars.

Minimum top reinforcement is provided in the slab in each direction for shrinkage and temperature crack control. In addition, top reinforcement located parallel to the stiffeners is used as tension reinforcement in negative bending. The stiffened plate provides crack control capability for the bottom of the slab in the transverse direction.

Composite section properties, based on an all steel-transformed section, as detailed in Section Q1.11 of ANSI/AISC N690-94, are used to check the following:

- *Weld strength between stiffener and the steel plate*
- *Spacing of the shear studs for the composite action*

The stiffened plate alone is designed to resist all construction loads prior to the concrete hardening. The plate is checked against the criteria for bending and shear, specified in ANSI/AISC N690-94, Sections Q1.5.1.4 and Q1.5.1.2. In addition, the weld between the stiffener and the steel plate is checked to satisfy the code requirements.]*

3H.5.5 Structural Modules

[*Structural modules are used for some of the structural elements on the south side of the auxiliary building. These structural modules are structural elements built up with welded steel structural shapes and plates. The modules consist of steel faceplates connected by steel trusses as shown in Figure 3.8.3-2. The primary purpose of the trusses is to stiffen and hold together the faceplates during handling, erection, and concrete placement. The thickness of the steel faceplates is 0.5 inch except in a few local areas. The nominal spacing of the trusses is 30 inches. Shear studs are welded to the inside faces of the steel faceplates. Faceplates are welded to adjacent faceplates with full penetration welds so that the weld is at least as strong as the plate. The structural wall modules are anchored to the concrete base by reinforcing steel dowels or other types of connections embedded in the reinforced concrete below. After erection, concrete is placed between the faceplates.*

These modules include the spent fuel pool, fuel transfer canal, and cask loading and cask washdown pits. The structural modules are similar to the structural modules for the containment internal structures (see description in subsection 3.8.3 and Figures 3.8.3-8, 3.8.3-14, 3.8.3-15 and 3.8.3-17). Figure 3.8.4-5 shows the location of the structural modules in the auxiliary building. The structural modules extend from elevation 66'-6" to elevation 135'-3".

The loads and load combinations applicable to the structural modules in the auxiliary building are the same as for the containment internal structures]* (subsection 3.8.3.5.3) [*except that there are no ADS nor pressure loads due to pipe breaks.*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

The design methodology of these modules in the auxiliary building is similar to the design of the structural modules in the containment internal structures]* described in subsection 3.8.3.5.3.

3H.5.5.1 West Wall of Spent Fuel Pool

[*Figure 3H.5-10 shows an elevation of the west wall of the spent fuel pool (column line L-2), and element numbers in the finite element model. The wall is a 4 feet thick concrete filled structural wall module.*

A finite element analysis of the spent fuel building module is performed for seismic, thermal and hydrostatic loads with the following assumptions:

- *The analysis model includes the structure between Lines 2 and 4, Lines I and N, and between El. 66'-6" and 135'-3", and is fixed at the base. There is no support at elevation 135'-3".*
- *The seismic input consists of floor response spectra derived from the spectra for the floor at El. 135'-3", which are conservatively applied at the basemat level as ground response spectra.*
- *The thermal loads are applied as linearly varying temperatures between the inner and outer faces of the walls and floors.*
- *The hydrostatic loads are applied to the spent fuel pool walls and floors, which is considered full with water. This provides the loads for the design of the divider wall.*
- *The seismic sloshing is modeled in the spent fuel pool.*

The concrete filled structural wall modules are designed as reinforced concrete structures in accordance with the requirements of ACI-349. The face plates are treated as reinforcing steel.

Methods of analysis are based on accepted principles of structural mechanics and are consistent with the geometry and boundary conditions of the structures. Both computer codes and hand calculations are used.

Table 3H.5-8 shows the magnitude of typical design loads, load combinations, and the required and provided plate thickness for certain critical locations. The steel plates are generally half inch thick. The plate thickness is increased close to the bottom of the gate through the wall where the opening results in high local member forces. The first part of the table shows the member forces due to individual loading. The lower part of the table shows the governing load combinations. The steel plate thickness required to resist mechanical loads is shown at the bottom of the table as well as the thickness provided. The maximum principal stress for the load combination including thermal is also tabulated. If this value exceeds the yield stress at temperature, a supplemental evaluation is performed. For these cases, the maximum stress intensity range is shown together with the allowable stress intensity range which is twice the yield stress at the temperature.]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

3H.5.6 Shield Building Roof

[*The shield building roof is a reinforced concrete shell supporting the passive containment cooling system tank and air diffuser. The structural configuration is shown on sheets 7, 8 and 9 of Figure 3.7.2-12. Air intakes are located at the top of the cylindrical portion of the shield building. The conical roof supports the passive containment cooling system tank as shown in Figure 3.8.4-7. The conical roof is constructed using double tee precast concrete panels with temporary support during erection on the containment vessel. The location of the precast panels and double tee webs are shown on sheet 1 of Figure 3H.5-11. The precast panels are six inches thick and the remaining 18 inches of concrete is cast in place after erection of the precast panels. The design of critical areas is discussed below. These areas include the tension ring at the connection of the conical roof to the cylindrical wall, the columns between the air inlets just below the air inlets, and the connection of the exterior wall of the passive containment cooling system tank to the conical roof.*]*

3H.5.6.1 Tension Ring

[*The connection between the conical roof and the air inlet columns is designated as the tension ring. It spans as a beam across the air inlets. The governing load for the tension ring is axial tension. The maximum tension is about 1200 kips under normal operating loads. SSE seismic loads result in maximum axial loads of about 1800 kips. The combined load ranges from 3000 kips tension to 600 kips compression. The maximum axial tension results in a reinforcement stress of 37 ksi. The reinforcement will also see tensile stresses due to other member force components, primarily torsion and bending about the horizontal axis. The maximum axial compression results in a concrete compressive stress of 270 psi. This is less than 10 percent of the concrete compressive strength. The ring is designed as a tension member; shear stirrups are provided to carry the shear and torsion without taking credit for concrete shear strength. The reinforcement is shown in Figure 3H.5-11. The reinforcement required and provided is summarized in sheet 1 of Table 3H.5-9.*]*

3H.5.6.2 Column (shear wall) between Air Inlets

[*The column between the air inlets has plan dimensions of 36" x 183" and is 78" high. Its primary loading is vertical load due to dead and seismic loads and horizontal seismic shear. It is designed as a shear wall. The axial compression is about 1400 kips under normal operating loads. SSE seismic loads result in maximum axial loads of about 1600 kips. The combined load ranges from 3000 kips compression to 300 kips tension. The maximum horizontal shear is 2600 kips in-plane and 800 kips out-of-plane (D.L. = 300, SSE = 500). The 3000 kips compression corresponds to an axial compressive stress of about 460 psi. These loads and the associated bending moments result in a maximum concrete compressive stress of 1000 psi and a maximum concrete tensile stress of 600 psi at the base of the column assuming gross concrete section properties. The reinforcement is shown in Figure 3H.5-11. The reinforcement required and provided is summarized in sheet 2 of Table 3H.5-9.*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

3H.5.6.3 Exterior Wall of the Passive Containment Cooling System Tank

[*The exterior wall of the passive containment cooling system tank is two feet thick. The wall starts at the tank floor elevation of 298' 9". There is a stainless steel liner on the inside surface of the tank. The wall liner consists of a plate with stiffeners and welded studs on the concrete side of the plate. Leak chase channels are provided over the liner welds. The reinforcement in the concrete wall is designed without taking credit for the strength provided by the liner. The governing loads for design of the exterior wall are the hydrostatic pressure of the water, the in-plane and out-of-plane seismic response, and the temperature gradient across the wall. The reinforcement is shown in sheet 8 of Figure 3H.5-11. The reinforcement required and provided is summarized in sheet 3 of Table 3H.5-9.*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-1

[*NUCLEAR ISLAND: DESIGN TEMPERATURES FOR THERMAL GRADIENT*]*

Structure	*Load*	*Temperature (°F)*		*Remark*
PCS Tank Walls	*Normal Thermal, T_o*	*(Outside)* *-40* *+115*	*(Inside)* *+40* *+40*	–
Roofs and Exterior Walls Above Grade Air Temperatures	*Normal Thermal, T_o*	*(Outside)* *-40* *+115*	*(Inside)* *+70* *+70*	–
	Accident Thermal, T_a	*-40* *-40*	*+132* *+212*	*MSIV room* *Fuel handling area*
Roofs and Exterior Walls Above Grade Concrete Temperatures	*Normal Thermal, T_o*	*(Outside)* *-21.6* *-22.8* *-25.4* *+3.2*	*(Inside)* *+47* *+48.4* *+51.5* *+46.6*	 *24" thickness* *27" thickness* *36" thickness* *15" insulated roof*
		+109.1 *+108.0* *+107.5* *+98.6*	*+79.2* *+80.7* *+81.3* *+81.3*	*24" thickness* *27" thickness* *36" thickness* *15" insulated roof*
	Accident Thermal, T_a	*-40* *-40* *+63*	*+132* *+212* *+212*	*MSIV room* *Fuel handling area* *Insulated roof*
Interior Walls/Slabs Concrete Temperatures	*Normal Thermal, T_o*	*(Side 1)* *N/R*	*(Side 2)* *N/R*	–
	Accident Thermal, T_a	*+70* *+70*	*+132* *+212*	*MSIV room* *Fuel handling area*
Exterior Walls Below Grade	*Normal Thermal, T_o*	*N/R*	*N/R*	–
	Accident Thermal, T_a	*N/R*	*N/R*	–
Basemat	*Normal Thermal, T_o*	*N/R*	*N/R*	–
	Accident Thermal, T_a	*N/R*	*N/R*	–
Shield Building (Between Upper Annulus and Auxiliary Building)	*Normal Thermal, T_o*	*(Outside)* *-40* *+115*	*(Inside)* *+70* *+70*	–
	Accident Thermal, T_a	*-40* *N/R*	*+132* *N/R*	*MSIV room wall* *Rest of wall*

Notes:
1. *N/R means loads due to a thermal gradient are not required to be considered.*
2. *Based on ACI 349-01 (Appendix A), the base temperature for the construction is assumed to be 70°F.*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-2 (Sheet 1 of 2)

**[*EXTERIOR WALL ON COLUMN LINE 1*
FORCES AND MOMENTS IN CRITICAL LOCATIONS]***

(See Figure 3H.5-2 for Locations of Wall Sections.)

Load Type	Load Description	Out-of-Plane Moment (k-ft/ft)						Out-of-Plane Shear (kips/ft)			
		Wall Section						Wall Section			
		1	2	3	4	5	6	1	3	4	6
D	DEAD LOAD										
	Wall Weight	-5.3	5.92	2.2	0.7	0.7	2.2	-1.4	-0.4	-0.4	0.6
	Static Surcharge	2.1	-1.7	0.5	0.4	-0.8	0.4	1.5	-1.9	2.2	-1.6
L	LIVE LOAD										
	Floor Live Load	-1.2	0.9	0.6	-0.1	-0.7	-0.3	-0.2	-0.2	-0.2	-0.2
	Crane/Cask Load	0	0	-0.1	-0.1	0.9	0.4	-0.2	-0.05	-0.2	-0.2
	Hydrostatic	29.2	-13.9	2.1	3.2	-1.3	1.2	14.4	-3.1	1.5	-0.5
H	LATERAL SOIL PRESSURE										
	At Rest Pressure	14.5	-6.9	2.1	2.5	-0.7	1.10	7.7	-1.6	0.6	-0.4
E_s	SEISMIC										
	Global Behavior	12.1	5.5	5.4	5.3	3.3	3.5	3.48	1.6	1.4	9.8
	Passive Soil Press.	-164.1	-76.5	7.4	11.2	-7.6	9.7	77.6	-19.8	-18.4	-3.6
	Dyn. Soil Press.	-103.1	-47.6	5.4	4.7	-15.1	-8.4	49.3	24.9	-9.0	-6.5
T_o	THERMAL										
	Operating	8.9	3.2	7.2	9.5	20.1	42.4	0.6	0.6	-1.5	-6.8

Notes:
Moment w/o sign indicates tension on the outside face of wall.
Moment w/- sign indicates tension on the inside face of wall.

Load Type	Load Description	In-Plane Axial and Shear Loads (kips/ft)[(1)]			
		Vertical		Horizontal	
		Tension/Compression	Shear	Tension/Compression	Shear
E_o	SEISMIC				
	El. 66.5' to 100.0'	154.8	93.8	23.0	93.8
	El. 100.0' to 180'	159.9	62.9	77.1	62.9

Note:
1. The in-plane loads provided in the table above are enveloping values for the wall panel at the elevations shown.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-2 (Sheet 2 of 2)

[*EXTERIOR WALL ON COLUMN LINE 1 FORCES AND MOMENTS IN CRITICAL LOCATIONS*]*

Load Type	Load Description	Out-of-Plane Moment (k-ft/ft)						Out-of-Plane Shear (kips/ft)			
		Wall Section						Wall Section			
		7	8	9	10	11	12	7	9	10	12
D	DEAD LOAD										
	Wall Weight	-2.2	3.7	2.3	0.7	0.2	0.2	0.05	0.05	0.1	0.2
	Static Surcharge	0.3	0	0	0	0	0	0.03	0.03	0	0
L	LIVE LOAD										
	Floor Live Load	-1.6	2.0	1.3	1.4	-1.8	-0.6	0.3	-0.2	-1.6	-1.6
	Crane/Cask Load	0.4	-2.6	-2.9	9.8	0.9	-1.8	-0.2	-0.3	-0.4	-0.7
	Hydrostatic	-1.60	0	0.40	0.40	0	0	-0.1	0	0	0
H	LATERAL SOIL PRESSURE										
	At Rest Pressure	1.1	0	-0.30	-0.2	0	0	0	0	0	0
E_s	SEISMIC										
	Global Behavior	25.2	74.4	78.7	79.1	115.4	27.7	13.1	4.3	13.7	13.5
	Passive Soil Press.	8.6	0	-0.1	-0.3	0	0	0	0	0	0
	Dyn. Soil Press.	7.3	0	0	0	0	0	0	0	0	0
T_o	THERMAL										
	Operating	51.2	65.4	74.5	77.6	43.1	12.4	-0.6	-1.2	6.2	3.6

Notes:
Moment w/o sign indicates tension on the outside face of wall.
Moment w/- sign indicates tension on the inside face of wall.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-3

**[*EXTERIOR WALL ON COLUMN LINE 1*
DETAILS OF WALL REINFORCEMENT (*in*^{2}*/ft*)]***

(See Figure 3H.5-2 for Locations of Wall Sections.)

Load Combination	Location	Required			Provided		
		Vertical	Horizontal	Shear	Vertical	Horizontal	Shear
WALL SECTION 1, 2, 3							
				0.5			0.80
$1.0D+1.0L+1.0H+1.0E_s$	Outside Face	2.9	1.1		4.16	1.27	
	Inside Face	1.9	1.1		2.67	1.27	
WALL SECTION 4, 5, 6							
				0.25			0.40
$1.0D+1.0L+1.0H+T_o$	Outside Face	1.4	1.0		3.12	1.27	
	Inside Face	1.4	1.15		2.67	1.27	
WALL SECTION 7, 8, 9							
				NR			None
$1.0D+1.0L+1.0H+1.0T_o$	Outside Face	2.5	3.0		3.12	3.12	
	Inside Face	2.1	1.2		3.12	1.69	
WALL SECTION 10, 11, 12							
				NR			None
$1.0D+1.0L+1.0H+1.0T_a$	Outside Face	2.8	2.5		3.74	3.12	
	Inside Face	1.2	1.5		3.12	2.34	

Note:
NR – Not Required

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-4

**[*INTERIOR WALL AT COLUMN LINE 7.3*
FORCES AND MOMENTS IN CRITICAL LOCATIONS]***

(Units: kips, ft)

Load Combination	M_X	M_Y	M_{XY}	T_X	T_Y	T_{XY}
From Roof to Elevation 135'-3"						
$0.9D - E_s$		37.7	54.6		157.2	253.9
$0.9D + T_o + E_s$	265.5		56.2	488.3		160.5
Elevation 135'-3" to 117'-6"						
$0.9D + T_o + E_s$		3.5	0.6		208.8	68.7
$D + L - E_s$	0.7		0.7	35.4		160.4
Elevation 117'-6" to 100'-0"						
$D + T_o + E_s$		14.4	3.0		146.2	132.0
$D + L - E_s$	0.7		1.5	117.9		205.7
Elevation 100'-0" to 82'-6"						
$0.9D + T_o – E_s$		5.5	1.2		93.7	182.5
$0.9D + T_o – E_s$	9.6		1.2	42.8		182.5
Elevation 82'-6" to 66'-6"						
$0.9D + T_o + E_s$		20.9	2.9		86.8	41.0
$D + L - E_s$	5.3		1.7	40.5		8.7

Note:
X is along the horizontal direction, and Y is in the vertical direction.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-5

[INTERIOR WALL ON COLUMN LINE 7.3 DETAILS OF WALL REINFORCEMENT]*

Wall Segment	***Location***	***Reinforcement on Each Face (in²/ft)***	
		Required	***Provided***
From Roof to Elevation 155'-6"	*Horizontal (1)*	*3.67*	*6.24*
	Vertical (1)	*2.86*	*3.12*
Elevation 155'-6" to 135'-3"	*Horizontal*	*4.47*	*5.66*
	Vertical	*4.30*	*5.66*
Elevation 135'-3" to 124'-0"	*Horizontal*	*1.76*	*2.06*
	Vertical	*2.20*	*2.56*
Elevation 124'-0" to 117'-6"	*Horizontal*	*1.75*	*2.06*
	Vertical	*2.44*	*2.56*
Elevation 117'-6" to 107'-0"	*Horizontal*	*2.99*	*3.12*
	Vertical	*2.78*	*3.12*
Elevation 107'-0" to 100'-0"	*Horizontal*	*2.30*	*2.56*
	Vertical	*2.86*	*3.12*
Elevation 100'-0" to 82'-6"	*Horizontal*	*1.93*	*2.06*
	Vertical	*2.29*	*2.54*
Elevation 82'-6" to 66'-6"	*Horizontal*	*0.78*	*1.00*
	Vertical	*0.97*	*1.44*
Wall Segment	***Location***	***Reinforcement (in²/ft²)***	
		Required	***Provided***
From Roof to Elevation 155'-6"	*Stirrups*	*2.61*	*3.60*
Elevation 155'-6" to 135'-3"	*Stirrups*	*2.05*	*2.64*

Note:

1. *Additional local reinforcement in this wall segment, at the interface with the shield building, is shown in the figure.*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-6

**[*INTERIOR WALL AT COLUMN LINE L*
FORCES AND MOMENTS IN CRITICAL LOCATIONS]***

(Units: kips, ft)

Load Combination	M_X	M_Y	M_{XY}	T_X	T_Y	T_{XY}
Elevation 117'-6" to 135'-3"						
$0.9D + E_s + R_a + P_a + Y_j$		256.9	65.0		40.3	118.0
$D + L + E_s + R_a + P_a + Y_j$	194.4		71.1	15.4		107.3

Note:
X is along the horizontal direction, and Y is in the vertical direction.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-7

**[*INTERIOR WALL ON COLUMN LINE L*
DETAILS OF WALL REINFORCEMENT]***

Wall Segment	*Type*	*Reinforcement (in^2/ft^2)*	
		Required	***Provided***
Elevation 117'-6" to 135'-3"	*Horizontal*	*3.45*	*4.39*
	Vertical	*5.00*	*5.37*
Shear Reinforcement:			
Elevation 117'-6" to 135'-3"	*T headed bars*	*2.07*	*2.64*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-8 (Sheet 1 of 5)

[*DESIGN SUMMARY OF SPENT FUEL POOL WALL DESIGN LOADS, LOAD COMBINATIONS, AND COMPARISONS TO ACCEPTANCE CRITERIA ELEMENT NO. 1218*]*

Load/Comb.	S_{xx} kip/ft	S_{yy} kip/ft	S_{xy} kip/ft	M_{xx} k-ft/ft	M_{yy} k-ft/ft	N_x kip/ft	N_y kip/ft	*Comments*
Dead (D)	0.17	-11.19	1.52	-0.33	-3.28			
Live (L)								
Hydro (F)	5.02	5.16	2.23	-19.94	-148.92	-1.47	-31.76	
In-pl Seis. (E_s)	37.55	25.06	24.37	7.51	55.30			
Out-pl Seis. (E_s)	10.02	40.75	65.73	38.28	285.23	4.09	46.27	
Thermal (T_a)	-479.15	-146.29	57.70	-418.7	346.38	-3.21	11.32	
LC (1)	7.26	-8.43	5.25	-28.39	-213.08	-2.06	-44.46	1.4D+1.4F
LC (2)								
LC (3a)	52.76	59.78	151.54	25.51	534.72	2.63	25.83	$1.0D+1.0F+1.0T_a+1.0E_s$
LC (3b)	-521.54	-218.12	-86.34	-484.80	-492.73	-8.77	-78.03	$1.0D+1.0F+1.0T_a-1.0E_s$
LC (4)	-473.97	-152.31	61.45	-439.02	194.18	-4.68	-20.44	$1.0D+1.0F+1.0T_a$
LC (5)								
LC (6a)	52.76	59.78	93.84	25.51	188.34	2.63	14.51	$1.0D+1.0F+1.0E_s$
LC (6b)	-42.39	-71.83	-86.34	-66.06	-492.73	-5.56	-78.03	$1.0D+1.0F-1.0E_s$
LC (7)								
LC (8)								
LC (9a)	52.75		93.69	25.54	188.66	2.63	14.51	$0.9D+1.0F+1.0E_s$
LC (9b)	-42.41	-70.71	-86.49	-66.03	-492.41	-5.56	-78.03	$0.9D+1.0F-1.0E_s$

Notes:
x- direction is horizontal; y- direction is vertical.
See Figure 3H.5-10 for element location.

Plate thickness required for load combinations excluding thermal: *0.28 inches*
Plate thickness provided: *0.50 inches*

Maximum principal stress for load combination 3 including thermal: *34.43 ksi*
Yield stress at temperature of 212°F: *43.96 ksi*

Maximum stress intensity range for load combination 3 including thermal: *N/A*
Allowable stress intensity range for load combination 3 including thermal: *87.92 ksi*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-8 (Sheet 2 of 5)

[*DESIGN SUMMARY OF SPENT FUEL POOL WALL DESIGN LOADS, LOAD COMBINATIONS, AND COMPARISONS TO ACCEPTANCE CRITERIA ELEMENT NO. 1236*]*

Load/Comb.	S_{xx} *kip/ft*	S_{yy} *kip/ft*	S_{xy} *kip/ft*	M_{xx} *k-ft/ft*	M_{yy} *k-ft/ft*	N_x *kip/ft*	N_y *kip/ft*	*Comments*
Dead (D)	2.97	-38.34	-7.30	-4.97	-13.71			
Live (L)								
Hydro (F)	4.91	0.74	-3.11	-18.04	-23.45	0.46	1.43	
In-pl Seis. (E_s)	152.33	103.11	111.13	11.46	227.73			
Out-pl Seis. (E_s)	8.00	78.00	43.13	30.59	47.23	7.07	15.88	
Thermal (T_a)	-83.04	-281.55	27.47	-708.87	-266.01	-125.35	-259.89	
LC (1)	11.04	-52.63	-14.57	-32.21	-52.03	0.65	2.00	1.4D+1.4F
LC (2)								
LC (3a)	168.22	143.52	171.33	19.04	237.79	7.54	17.30	$1.0D+1.0F+1.0T_a+1.0E_s$
LC (3b)	-235.49	-500.26	-164.67	-773.93	-578.13	-131.96	-274.34	$1.0D+1.0F+1.0T_a-1.0E_s$
LC (4)	-75.16	-319.15	17.06	-731.88	-303.17	-124.89	-258.46	$1.0D+1.0F+1.0T_a$
LC (5)								
LC (6a)	168.22	143.52	143.86	19.04	237.79	7.54	17.30	$1.0D+1.0F+1.0E_s$
LC (6b)	-152.45	-218.71	-164.67	-65.06	-312.12	-6.61	-14.45	$1.0D+1.0F-1.0E_s$
LC (7)								
LC (8)								
LC (9a)	167.92	147.35	144.59	19.54	239.16	7.54	17.30	$0.9D+1.0F+1.0E_s$
LC (9b)	-152.75	-214.88	-163.94	-64.56	-310.75	-6.61	-14.45	$0.9D+1.0F-1.0E_s$

Notes:
x- direction is horizontal; y- direction is vertical.

Plate thickness required for load combinations excluding thermal: *0.38 inches*
Plate thickness provided: *0.50 inches*

Maximum principal stress for load combination 3 including thermal: *40.91 ksi*
Yield stress at temperature of 212°F: *43.96 ksi*

Maximum stress intensity range for load combination 3 including thermal: *N/A*
Allowable stress intensity range for load combination 3 including thermal: *87.92 ksi*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-8 (Sheet 3 of 5)

[*DESIGN SUMMARY OF SPENT FUEL POOL WALL DESIGN LOADS, LOAD COMBINATIONS, AND COMPARISONS TO ACCEPTANCE CRITERIA ELEMENT NO. 1243*]*

Load/Comb.	S_{xx} *kip/ft*	S_{yy} *kip/ft*	S_{xy} *kip/ft*	M_{xx} *k-ft/ft*	M_{yy} *k-ft/ft*	N_x *kip/ft*	N_y *kip/ft*	*Comments*
Dead (D)	*0.30*	*-21.65*	*-1.14*	*6.03*	*1.26*			
Live (L)								
Hydro (F)	*11.74*	*0.13*	*2.02*	*-108.00*	*-14.29*	*20.48*	*5.19*	
In-pl Seis. (E_s)	*55.75*	*51.72*	*55.12*	*83.13*	*248.46*			
Out-pl Seis. (E_s)	*43.50*	*24.67*	*41.18*	*265.98*	*46.24*	*36.98*	*27.45*	
Thermal (T_a)	*-101.02*	*-359.38*	*-154.76*	*686.63*	*616.66*	*-47.53*	*15.37*	
LC (1)	*16.86*	*-30.12*	*1.24*	*-142.76*	*-18.24*	*28.67*	*7.26*	*1.4D+1.4F*
LC (2)								
LC (3a)	*111.29*	*54.88*	*97.19*	*933.78*	*898.33*	*57.46*	*48.01*	$1.0D+1.0F+1.0T_a+1.0E_s$
LC (3b)	*-188.22*	*-457.29*	*-250.18*	*-451.08*	*-307.73*	*-64.04*	*-22.26*	$1.0D+1.0F+1.0T_a-1.0E_s$
LC (4)	*-88.98*	*-380.89*	*-153.87*	*584.66*	*603.63*	*-27.06*	*20.56*	$1.0D+1.0F+1.0T_a$
LC (5)								
LC (6a)	*111.29*	*54.88*	*97.19*	*247.15*	*281.67*	*57.46*	*32.63*	$1.0D+1.0F+1.0E_s$
LC (6b)	*-87.20*	*-97.91*	*-95.42*	*-451.08*	*-307.73*	*-16.51*	*-22.26*	$1.0D+1.0F-1.0E_s$
LC (7)								
LC (8)								
LC (9a)	*111.26*	*57.05*	*97.306*	*246.54*	*281.55*	*57.46*	*32.63*	$0.9D+1.0F+1.0E_s$
LC (9b)	*-87.23*	*-95.74*	*-95.30*	*-451.68*	*-307.86*	*-16.51*	*-22.26*	$0.9D+1.0F-1.0E_s$

Notes:
x- direction is horizontal; y- direction is vertical.

Plate thickness required for load combinations excluding thermal: *0.27 inches*
Plate thickness provided: *0.50 inches*

Maximum principal stress for load combination 3 including thermal: *56.60 ksi*
Yield stress at temperature of 212°F: *43.96 ksi*

Maximum stress intensity range for load combination 3 including thermal: *56.60 ksi*
Allowable stress intensity range for load combination 3 including thermal: *87.92 ksi*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-8 (Sheet 4 of 5)

*[DESIGN SUMMARY OF SPENT FUEL POOL WALL
DESIGN LOADS, LOAD COMBINATIONS, AND COMPARISONS TO
ACCEPTANCE CRITERIA ELEMENT NO. 1248]**

Load/Comb.	S_{xx} kip/ft	S_{yy} kip/ft	S_{xy} kip/ft	M_{xx} k-ft/ft	M_{yy} k-ft/ft	N_x kip/ft	N_y kip/ft	Comments
Dead (D)	0.30	-21.65	-1.14	6.03	1.26			
Live (L)								
Hydro (F)	7.69	0.24	3.90	55.37	28.63	1.05	0.91	
In-pl Seis. (E_s)	55.75	51.72	55.12	83.13	248.46			
Out-pl Seis. (E_s)	35.86	23.37	52.82	115.25	90.68	3.00	4.89	
Thermal (T_a)	20.82	-92.55	37.81	337.08	357.75	-15.18	15.18	
LC (1)	11.19	-29.97	3.87	85.96	41.85	1.47	1.27	1.4D+1.4F
LC (2)								
LC (3a)	120.42	53.69	148.52	596.86	726.78	4.05	20.97	$1.0D+1.0F+1.0T_a+1.0E_s$
LC (3b)	-83.62	-189.05	-105.18	-136.99	-309.24	-17.13	-3.98	$1.0D+1.0F+1.0T_a-1.0E_s$
LC (4)	28.81	-113.96	40.58	398.48	387.64	-14.13	16.08	$1.0D+1.0F+1.0T_a$
LC (5)								
LC (6a)	99.60	53.69	110.71	259.78	369.03	4.05	5.79	$1.0D+1.0F+1.0E_s$
LC (6b)	-83.62	-96.50	-105.18	-136.99	-309.24	-1.95	-3.98	$1.0D+1.0F-1.0E_s$
LC (7)								
LC (8)								
LC (9a)	99.569	55.85	110.82	259.18	368.9	4.05	5.79	$0.9D+1.0F+1.0E_s$
LC (9b)	-83.65	-94.34	-105.06	-137.59	-309.37	-1.95	-3.98	$0.9D+1.0F-1.0E_s$

Notes:

x- direction is horizontal; y- direction is vertical.

Plate thickness required for load combinations excluding thermal: 0.30 inches
Plate thickness provided: 0.50 inches

Maximum principal stress for load combination 3 including thermal: 49.25 ksi
Yield stress at temperature of 212°F: 43.96 ksi

Maximum stress intensity range for load combination 3 including thermal: 49.25 ksi
Allowable stress intensity range for load combination 3 including thermal: 87.92 ksi

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-8 (Sheet 5 of 5)

[*DESIGN SUMMARY OF SPENT FUEL POOL WALL DESIGN LOADS, LOAD COMBINATIONS, AND COMPARISONS TO ACCEPTANCE CRITERIA ELEMENT NO. 1287*]*

Load/Comb.	S_{xx} kip/ft	S_{yy} kip/ft	S_{xy} kip/ft	M_{xx} k-ft/ft	M_{yy} k-ft/ft	N_x kip/ft	N_y kip/ft	*Comments*
Dead (D)	1.62	3.79	-3.56	0.20	-4.07			
Live (L)								
Hydro (F)	10.63	7.22	7.96	54.47	-62.63	-20.95	-55.72	
In-pl Seis. (E_s)	33.36	167.82	76.36	85.46	539.41			
Out-pl Seis. (E_s)	48.18	148.07	60.36	144.73	413.94	67.11	183.91	
Thermal (T_a)	127.96	337.53	140.02	368.33	301.06	-29.43	-135.14	
LC (1)	17.14	15.41	6.17	76.54	-93.39	-29.32	-78.00	1.4D+1.4F
LC (2)								
LC (3a)	221.75	664.43	281.15	653	1187	46.16	128.20	$1.0D+1.0F+1.0T_a+1.0E_s$
LC (3b)	-69.30	-304.89	-132.32	-175.5	-1020.0	-117.49	-239.63	$1.0D+1.0F+1.0T_a-1.0E_s$
LC (4)	140.21	348.54	144.43	423.00	234.35	-50.38	-190.86	$1.0D+1.0F+1.0T_a$
LC (5)								
LC (6a)	93.79	326.90	141.13	284.86	886.64	46.16	128.20	$1.0D+1.0F+1.0E_s$
LC (6b)	-69.30	-304.89	-132.32	-175.52	-1020.0	-88.05	-239.63	$1.0D+1.0F-1.0E_s$
LC (7)								
LC (8)								
LC (9a)	93.625	326.52	141.48	284.84	887.04	46.16	128.20	$0.9D+1.0F+1.0E_s$
LC (9b)	-69.46	-305.27	-131.96	-175.54	-1019.6	-88.05	-239.63	$0.9D+1.0F-1.0E_s$

Notes:

x- direction is horizontal; y- direction is vertical.

Plate thickness required for load combinations excluding thermal: 0.84 inches
Plate thickness provided: 0.875 inches

Maximum principal stress for load combination 3 including thermal: 77.87 ksi
Yield stress at temperature of 212°F: 43.96 ksi

Maximum stress intensity range for load combination 3 including thermal: 77.87 ksi
Allowable stress intensity range for load combination 3 including thermal: 87.92 ksi

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-9 (Sheet 1 of 3)

[*SHIELD BUILDING ROOF REINFORCEMENT SUMMARY*]*

(Tension Ring)

Member Force	***Reinforcement Required in²/in Length***	***Reinforcement Provided***	***Reinforcement Provided in²/in Length***	***Ratio Required/ Provided***
Axial + bending		*36 # 14 bars*		*0.77 (1)*
Torsion	*0.078*	*#9 hoop @ 0.45°*	*0.15*	*0.50*
Torsion + vertical shear	*2 x 0.078 + 0.26 = 0.42*	*2 legs # 9 hoop @ 0.45°* *2 # 8 ties @ 0.9°*	*0.42*	*0.99*
Torsion + horizontal shear	*2 x 0.078 + 0.15 = 0.31*	*2 legs # 9 hoop stirrup @ 0.45°* *3 # 5 ties @ 1.8°*	*0.33*	*0.92*

Note:
1. *This ratio is calculated from the interaction diagram for axial load and moments for the section and does not include the effect of torsion loading. It is the ratio of the loads on the interaction surface divided by the design loads for the same ratio of axial loads and moments.*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-9 (Sheet 2 of 3)

[*SHIELD BUILDING ROOF REINFORCEMENT SUMMARY*]*

(Air Inlet Column)

Member Force	***Reinforcement Required in^2/in Height***	***Reinforcement Provided***	***Reinforcement Provided in^2/in Height***	***Ratio Required/ Provided***
Axial + bending		*48 # 11 bars*		*0.58 (1,2)*
Torsion	*0.015*	*#5 hoop at 6"*	*0.05*	*0.30*
Torsion + in-plane shear	*2 x 0.015 + 0.20 = 0.23*	*3 # 7 ties @ 6"*	*0.30*	*0.77*
Torsion + out-of-plane shear	*0.37*	*# 5 hoop @ 6"* *9 # 5 ties @ 6"*	*0.56*	*0.66*

Notes:

1. *This ratio is calculated from the interaction diagram for axial load and moments for the section and does not include the effect of torsion loading. It is the ratio of the loads on the interaction surface divided by the design loads for the same ratio of axial loads and moments.*
2. *The vertical reinforcement in the column is provided to meet minimum vertical reinforcement requirements for shear walls.*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-9 (Sheet 3 of 3)

[*SHIELD BUILDING ROOF REINFORCEMENT SUMMARY*]*

(Exterior Wall of the Passive Containment Cooling System Tank)

Wall Segment	*Location*	*Reinforcement on Each Face, in²/ft*		
		Required	*Provided*	
Elevation 298'-9" to 321'-6"	*Horizontal*	*1.81*	*#9 @ 6"*	*2.00*
Elevation 321'-6" to 332'-2"	*Horizontal*	*1.10*	*#7 @ 6"*	*1.20*
Elevation 298'-9" to 303'	*Vertical*	*1.95*	*#11 @ 0.9°* *#11 @ 3.6°*	*2.80*
Elevation 303' to 317'	*Vertical*	*1.16*	*#11 @ 0.9°*	*2.24*
Elevation 317' to 332'-2"	*Vertical*	*0.98*	*#11 @ 1.8°*	*1.12*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-10

[*DESIGN SUMMARY OF ROOF AT ELEVATION 180'-0", AREA 6*]*

(Near Shield Building Interface)

Governing Load Combination (Roof Girder)	
Combination Number	*3 – Extreme Environmental Condition Downward Seismic Acceleration*
Bending Moment	*= 6416 kips-ft*
Corresponding Stress	*= 24.4 ksi*
Allowable Stress	*= 33.3 ksi*
Shear Force	*= 403 kips*
Corresponding Stress	*= 15.3 ksi*
Allowable Stress	*= 20.1 ksi*
Governing Load Combination (Concrete Slab)	
Parallel to the Girders	
Combination Numbers	*3 – Extreme Environmental Condition Upward Seismic Acceleration*
Reinforcement (Each Face)	
Required	*= 1.50 in^2/ft*
Provided	*= 1.56 in^2/ft*
Perpendicular to the Girders	
Combination Numbers	*3 – Extreme Environmental Condition*
Reinforcement (Each Face)	
Required	*= 1.35 in^2/ft*
Provided	*= 3.12 in^2/ft*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-11

**[*DESIGN SUMMARY OF FLOOR AT ELEVATION 135'-3"*
AREA 1 (BETWEEN COLUMN LINES M AND P)]***

Governing Load Combination (Steel Beam)	
Load Combination	*Normal Condition*
Bending Moment	*= (-) 64.4 kips-ft*
Corresponding Stress	*= 16.6 ksi*
Allowable Stress	*= 23.76 ksi*
Shear Force	*= 25.4 kips*
Corresponding Stress	*= 9.8 ksi*
Allowable Stress	*= 14.4 ksi*
Governing Load Combination (Concrete Slab)	
Parallel to the Beams	
Load Combination	*3 – Extreme Environmental Condition Downward Seismic*
Bending Moment	*= (+) 6.86 kips-ft/ft*
In-plane Shear	*= 17.8 kips (per foot width of the slab)*
Reinforcement (Each Face)	
Required	*< 1.49* in^2/ft
Provided	*= 1.56* in^2/ft
Perpendicular to the Beams	
Combination Number	*Normal Condition*
Bending Moment	*= (-) 8.28 kips-ft (per foot width of the slab)*
Reinforcement (Each Face)	
Required	*= 0.47* in^2/ft
Provided	*= 0.60* in^2/ft

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-12

[*DESIGN SUMMARY OF FLOOR AT ELEVATION 135'-3" AREA 1 (TAGGING ROOM CEILING)*]*

Design of Precast Concrete Panels	
Governing Load Combination	*Construction*
Design Bending Moment (Midspan)	*= 14.53 ft-kip/ft*
Bottom Reinforcement (E/W Direction)	
Required	*= 0.51 in^2/ft*
Provided	*= 0.79 in^2/ft*
Top Reinforcement (E/W Direction)	
Required	*= (Minimum required by Code)*
Provided	*= 0.20 in^2/ft*
Top and Bottom Reinforcement (N/S Direction)	
Required	*= (Minimum required by Code)*
Provided	*= 0.20 in^2/ft*
Design of 24-inch-Thick Slab	
Governing Load Combination	*Extreme Environmental Condition (SSE)*
Design Bending Moment (N/S Direction) Midspan	*= 5.46 kips ft/ft*
Design In-plane Shear	*= 25.4 kips/ft*
Design In-plane Tension	*= 14.7 kips/ft*
Bottom Reinforcement (E/W Direction)	
Required	*< 0.64 in^2/ft*
Provided	*= 0.79 in^2/ft*
Design Bending Moment (N/S Direction) at Support	*= 5.46 kips-ft/ft*
Design In-plane Shear	*= 25.4 kips/ft*
Design In-plane Tension	*= 14.7 kips/ft*
Top Reinforcement (E/W Direction)	
Required	*< 0.78 in^2/ft*
Provided	*= 0.79 in^2/ft*
Design Bending Moment (N/S Direction)	*= 4.3 kips ft/ft*
Design In-plane Shear	*= 25.4 kips/ft*
Design In-plane Tension	*= 13.96 kips/ft*
Top and Bottom Reinforcement (N/S Direction)	
Required	*< 0.64 in^2/ft*
Provided	*= 0.79 in^2/ft*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 3H.5-13

**[*DESIGN SUMMARY OF FLOOR AT ELEVATION 135'-3"*
AREA 1 (MAIN CONTROL ROOM CEILING)]***

The design of the bottom plate with fins is governed by the construction load.

For the composite floor, the design forces used for the evaluation of a typical 9-inch-wide strip of the slab are as follows:

Maximum bending moment	=	*+39.9 (-47.5) kips-ft*
Maximum shear force	=	*22.3 kips*

The design evaluation results are summarized below:

- *The actual area of the tension steel is 9.0 in^2, which provides a design strength of 518.5 kips-ft bending moment capacity.*
- *The design shear strength is 23.22 kips.*
- *The shear studs are spaced 9 inches c/c, in both directions. The calculated required spacing is 15.7 inches.*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

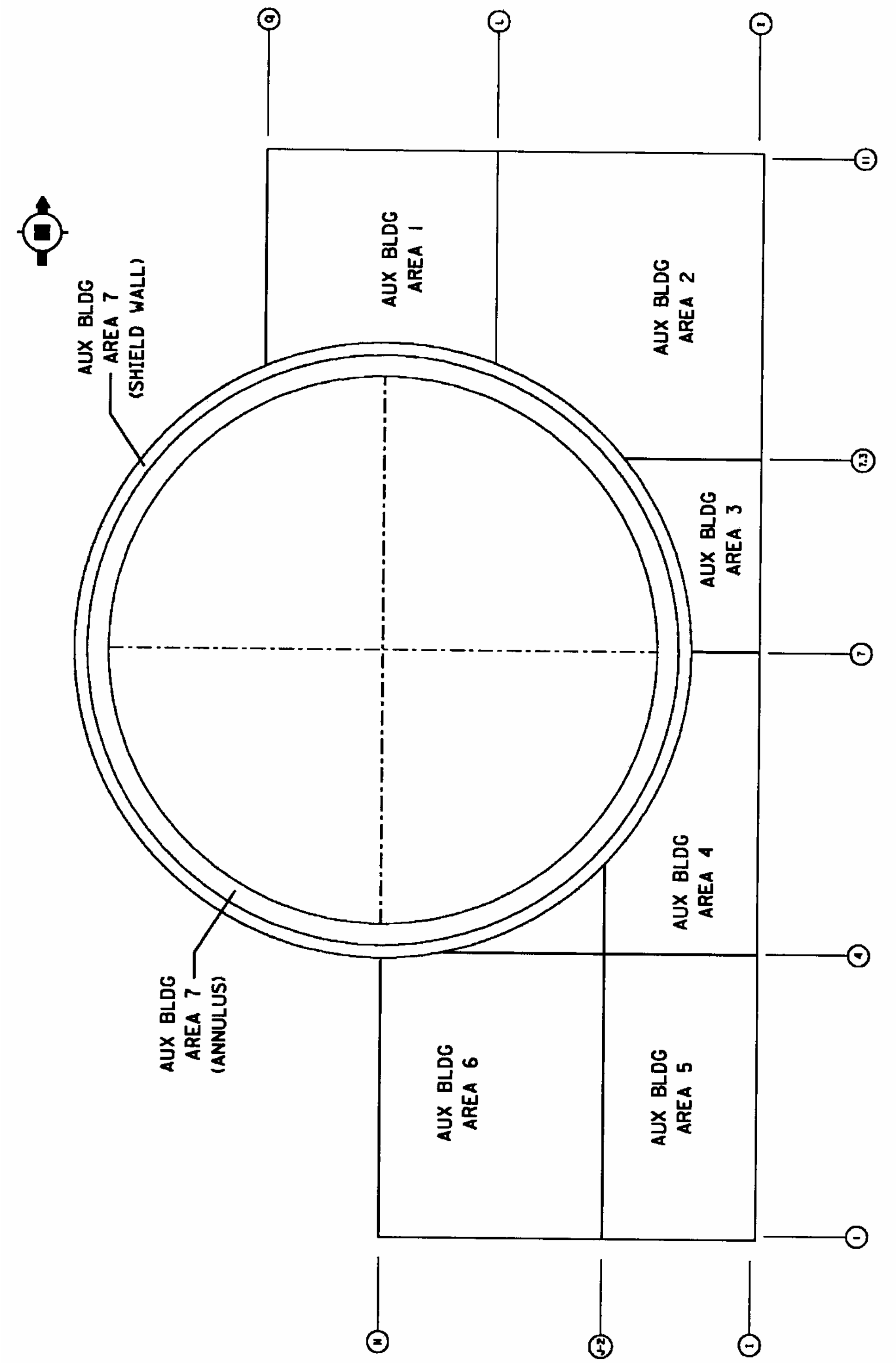


Figure 3H.2-1

[*General Layout of Auxiliary Building*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

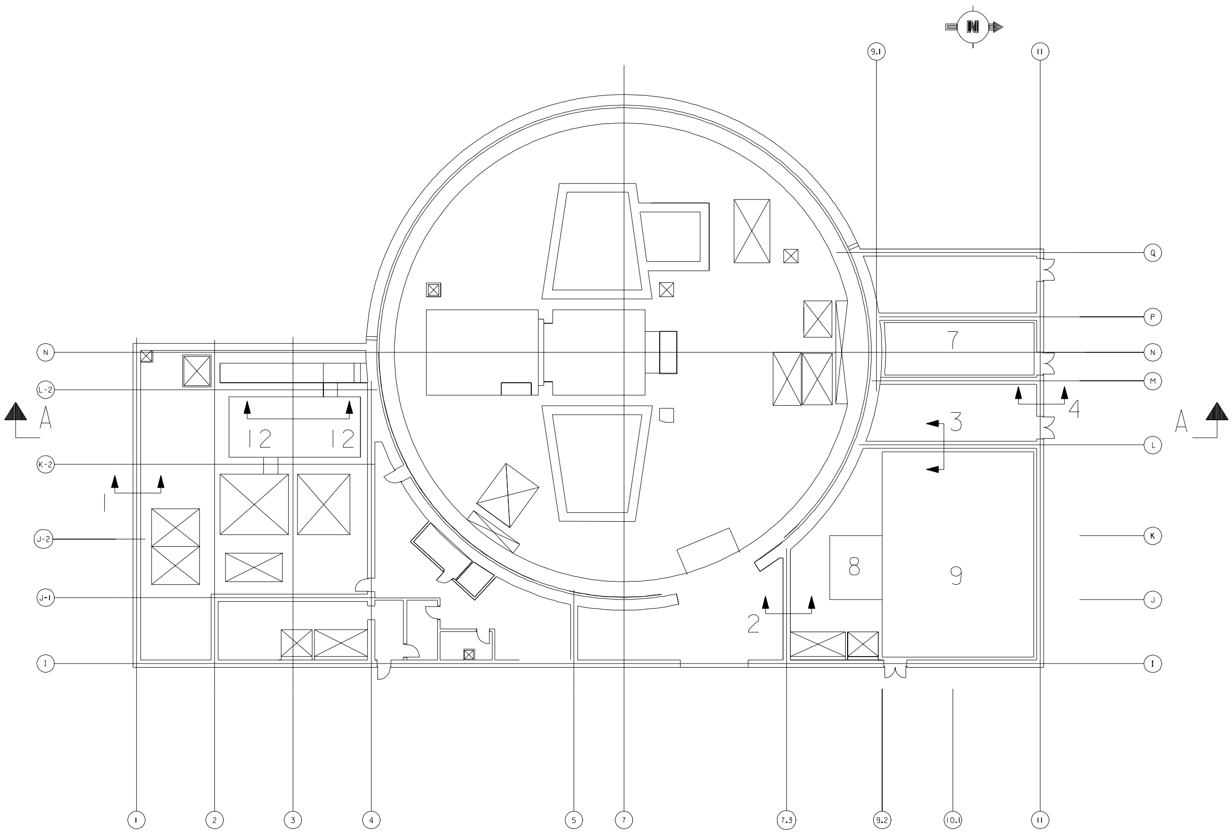


Figure 3H.5-1 (Sheet 1 of 3)

[*Nuclear Island Critical Sections Plan at El. 135'-3"*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

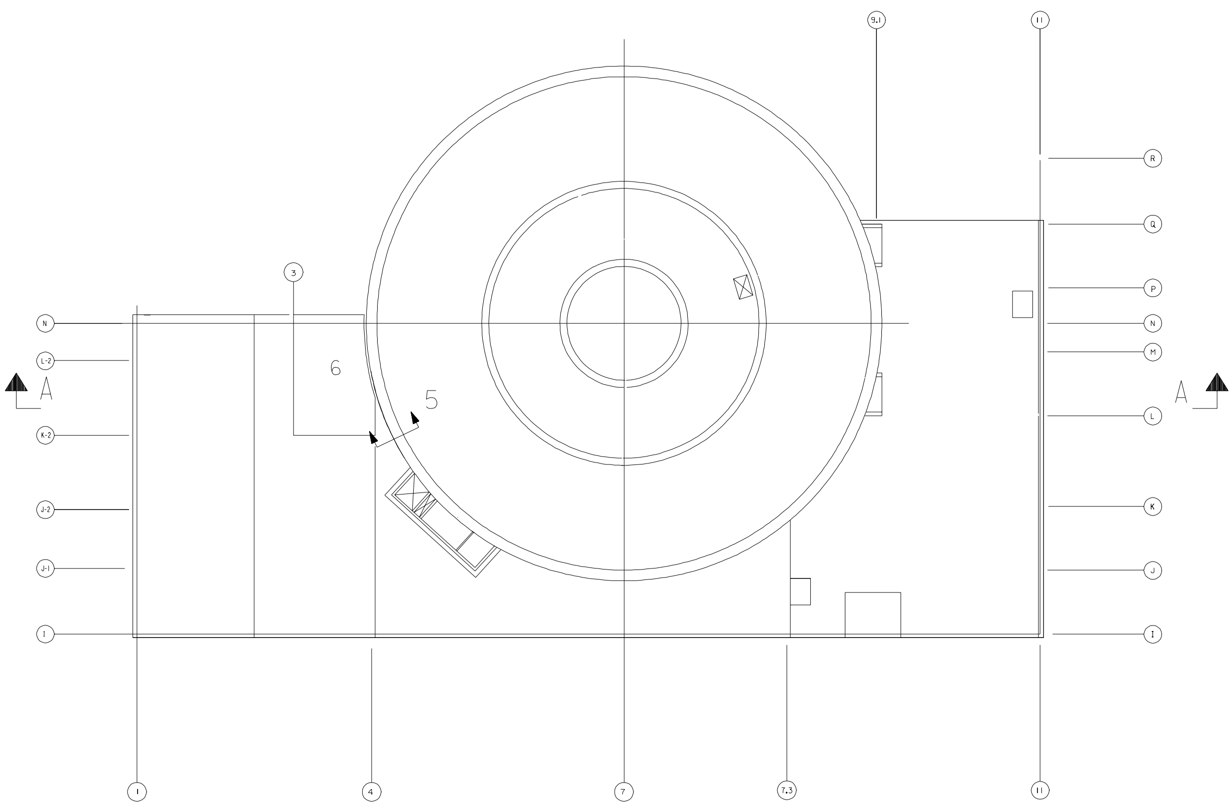


Figure 3H.5-1 (Sheet 2 of 3)

[***Nuclear Island Critical Sections***
Plan at El. 180'-0"]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

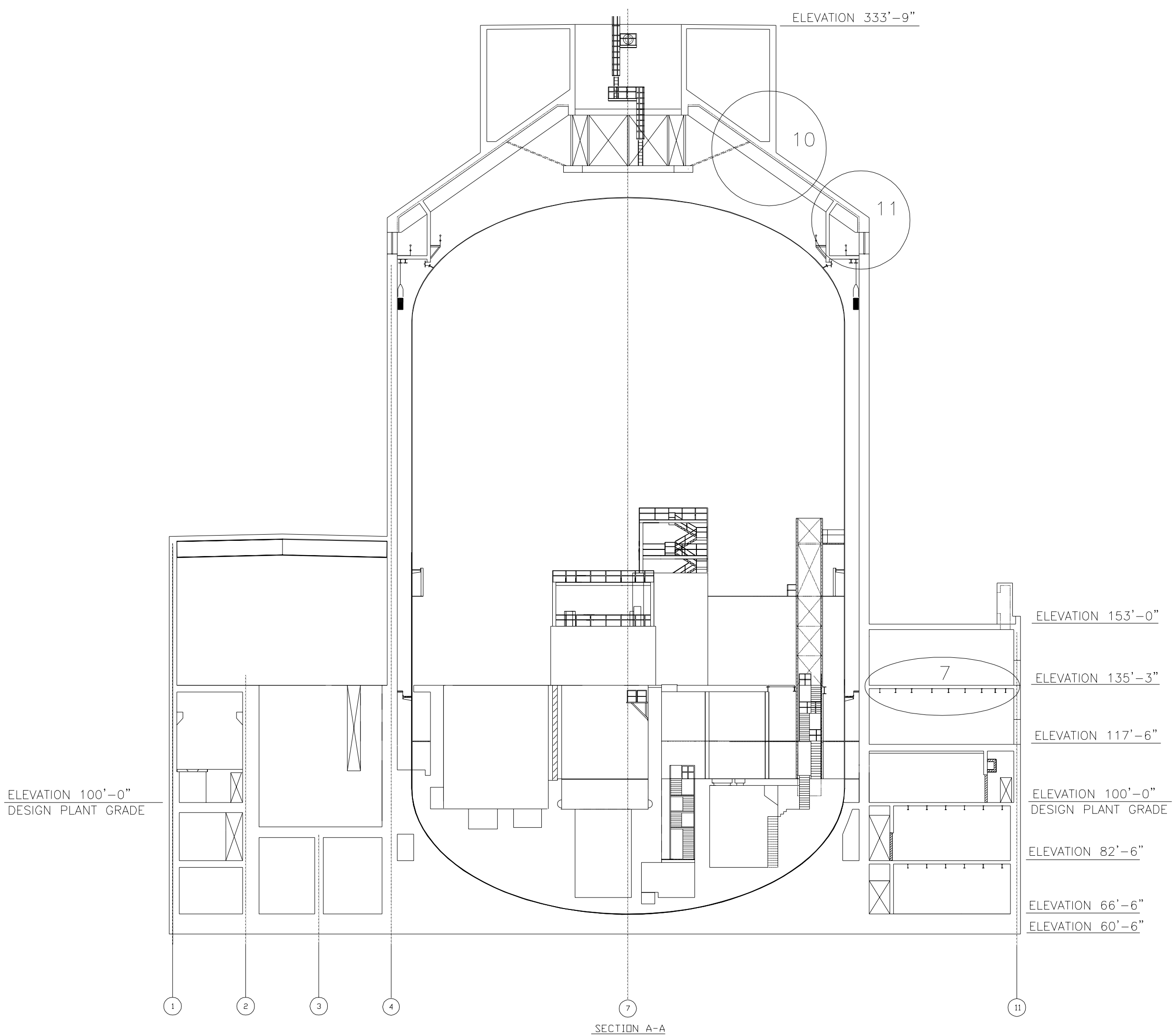


Figure 3H.5-1 (Sheet 3 of 3)

**[*Nuclear Island Critical Sections*
Section A-A]***

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

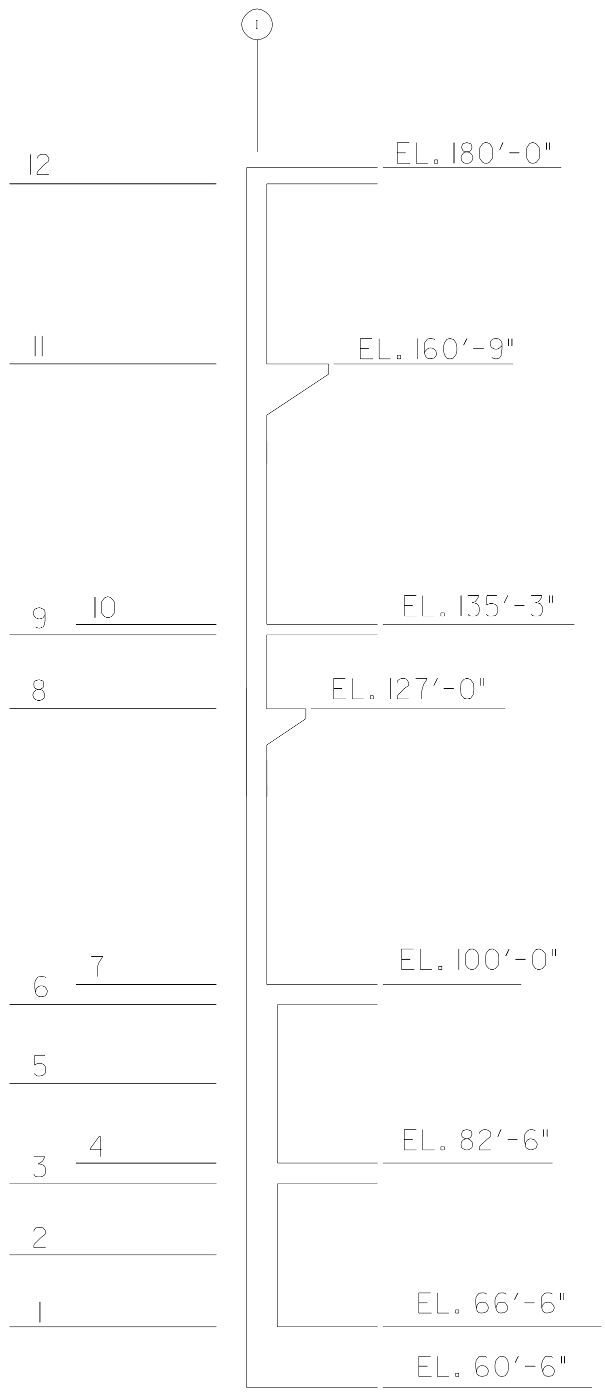


Figure 3H.5-2

[*Wall on Column Line 1*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

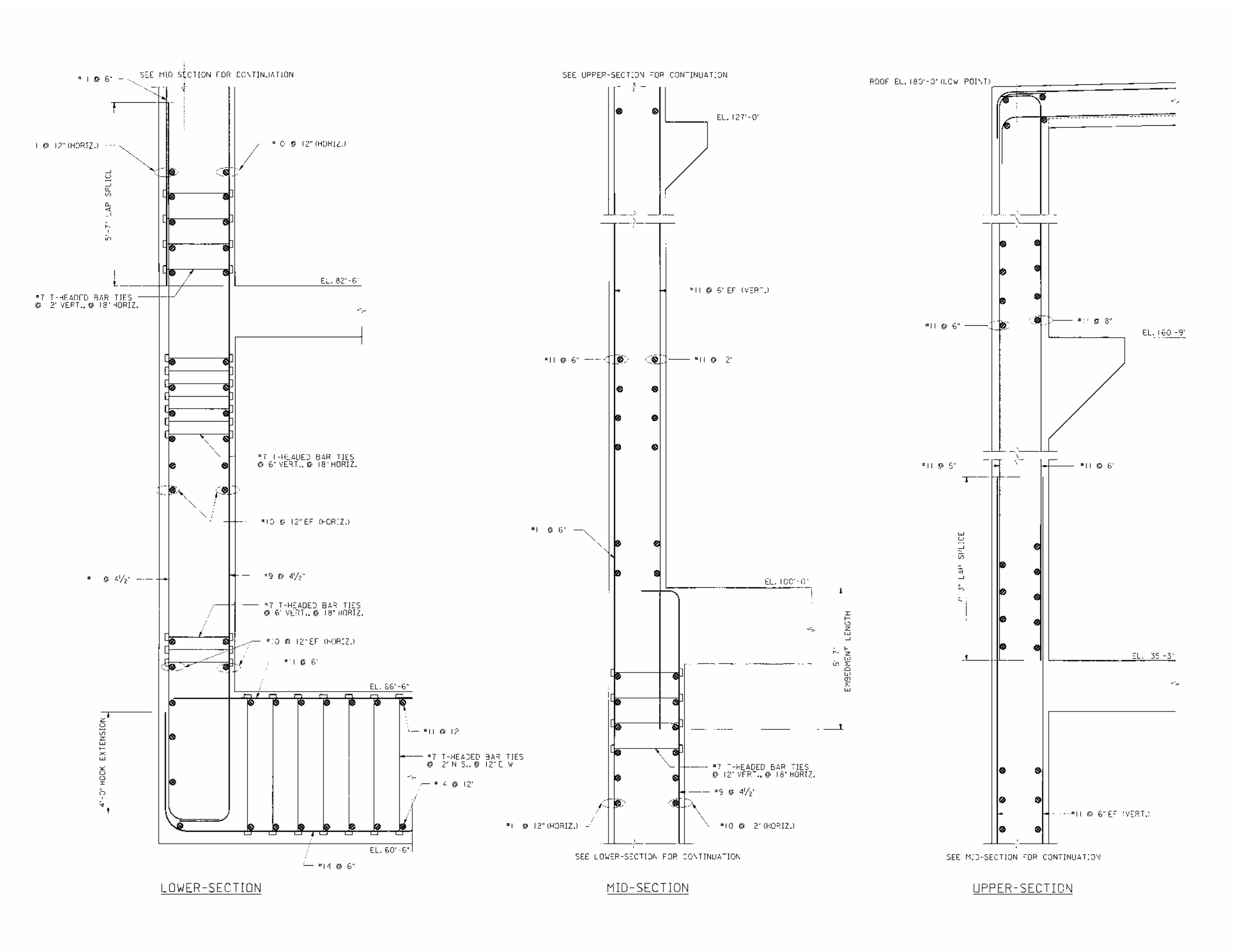


Figure 3H.5-3

[*Typical Reinforcement in Wall on Column Line 1*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

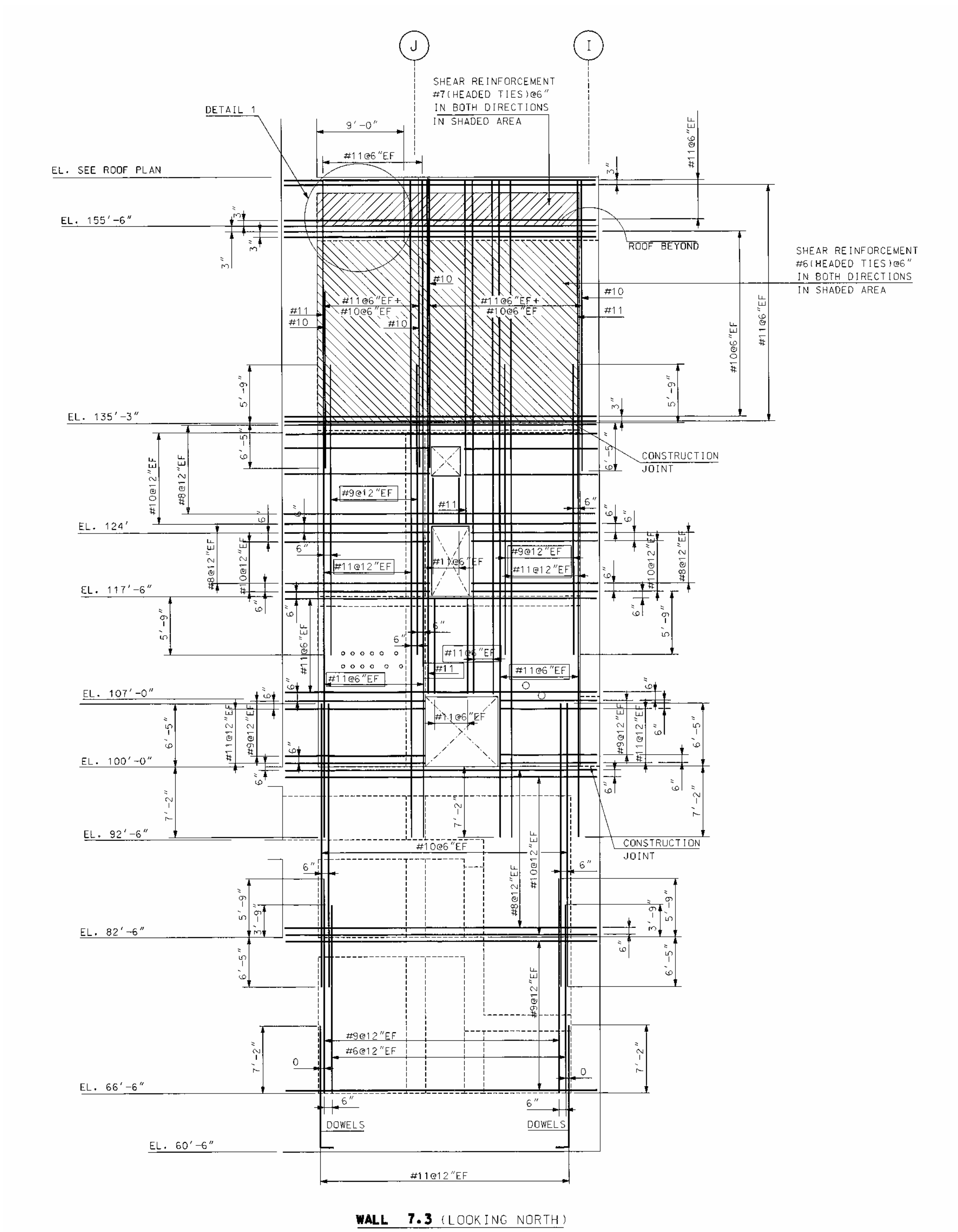
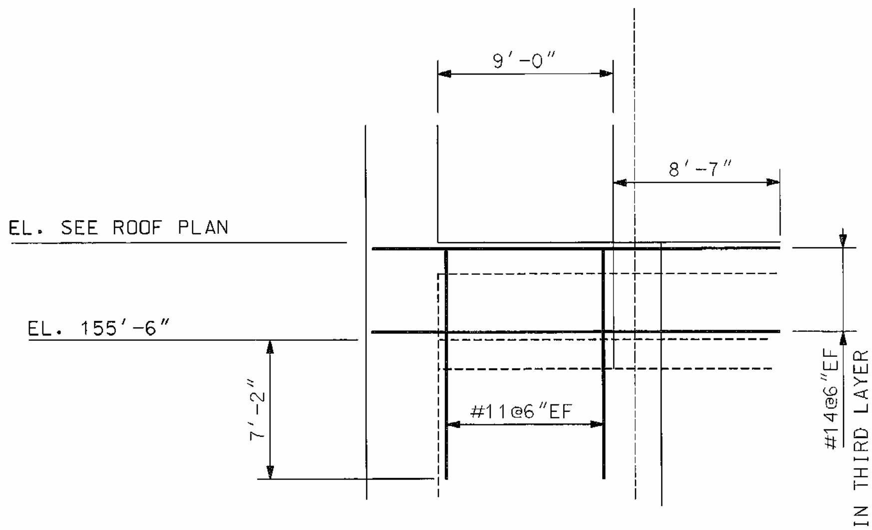


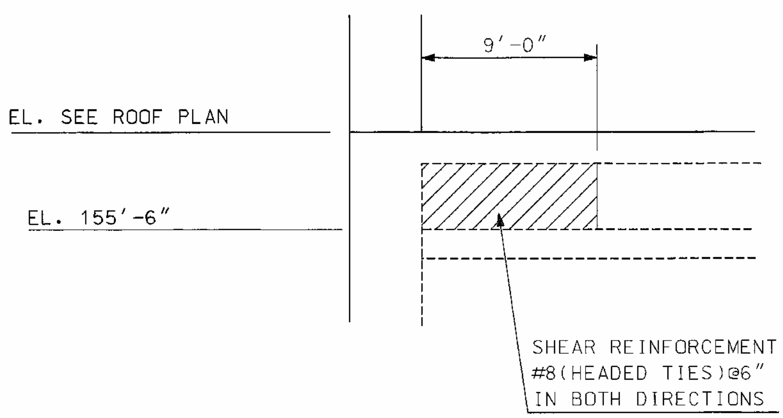
Figure 3H.5-4 (Sheet 1 of 2)

[*Typical Reinforcement in Wall 7.3*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.



DETAIL 1
ADDITIONAL REINFORCEMENT



DETAIL 1
ADDITIONAL SHEAR REINFORCEMENT

Figure 3H.5-4 (Sheet 2 of 2)

[*Typical Reinforcement in Wall 7.3 (Additional Details)*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

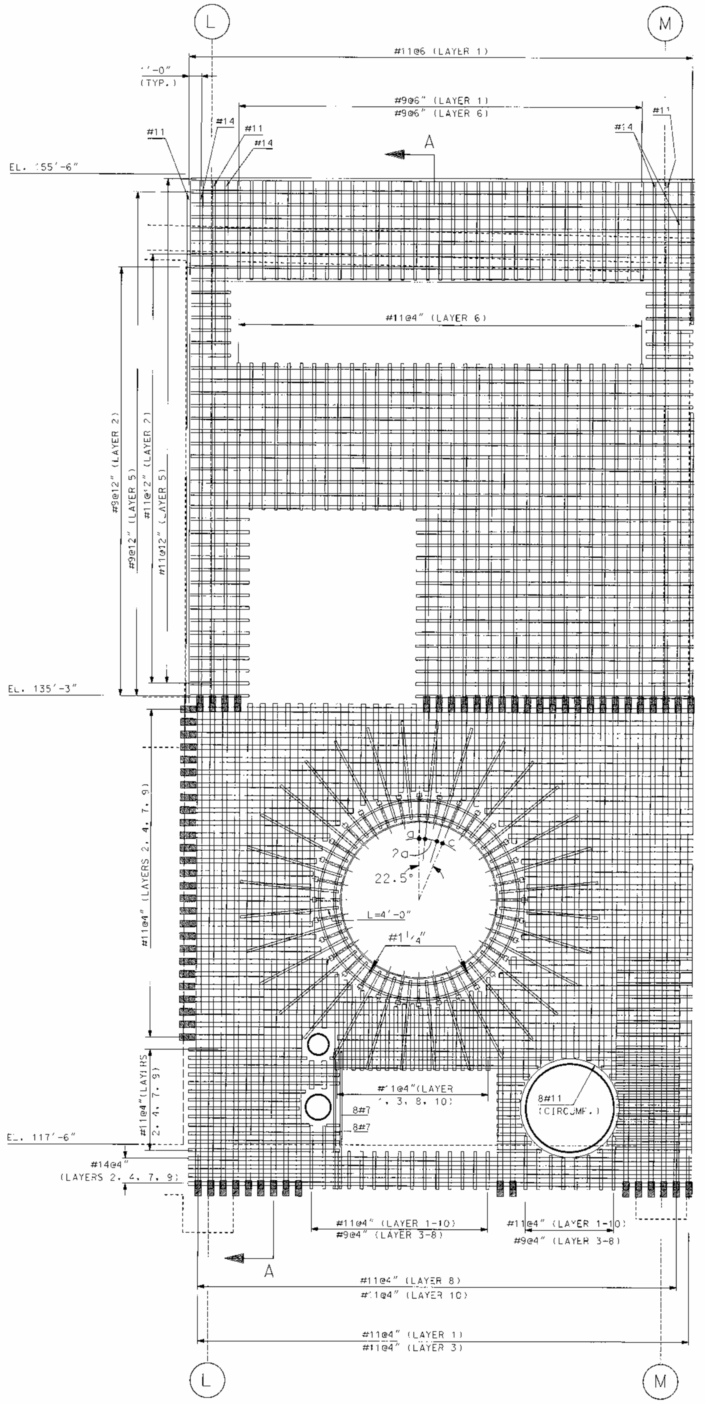


Figure 3H.5-5 (Sheet 1 of 3)

[*Concrete Reinforcement in Wall 11*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

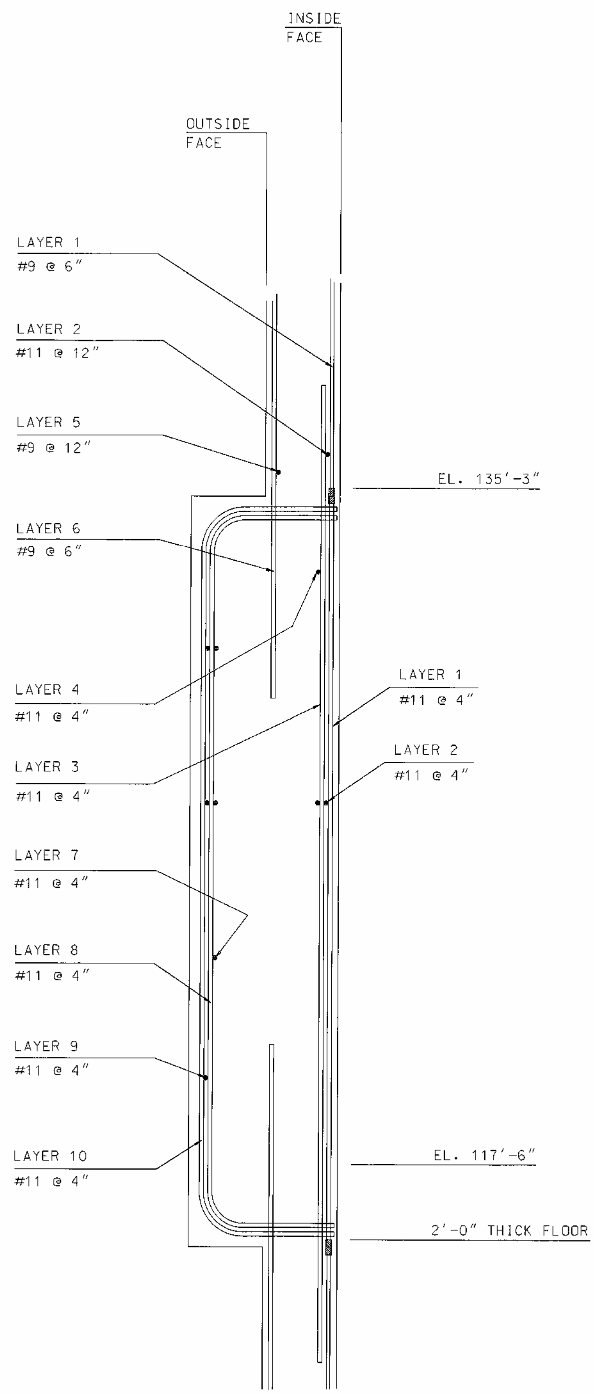


Figure 3H.5-5 (Sheet 2 of 3)

[***Concrete Reinforcement Layers in Wall 11 (Looking East)***]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

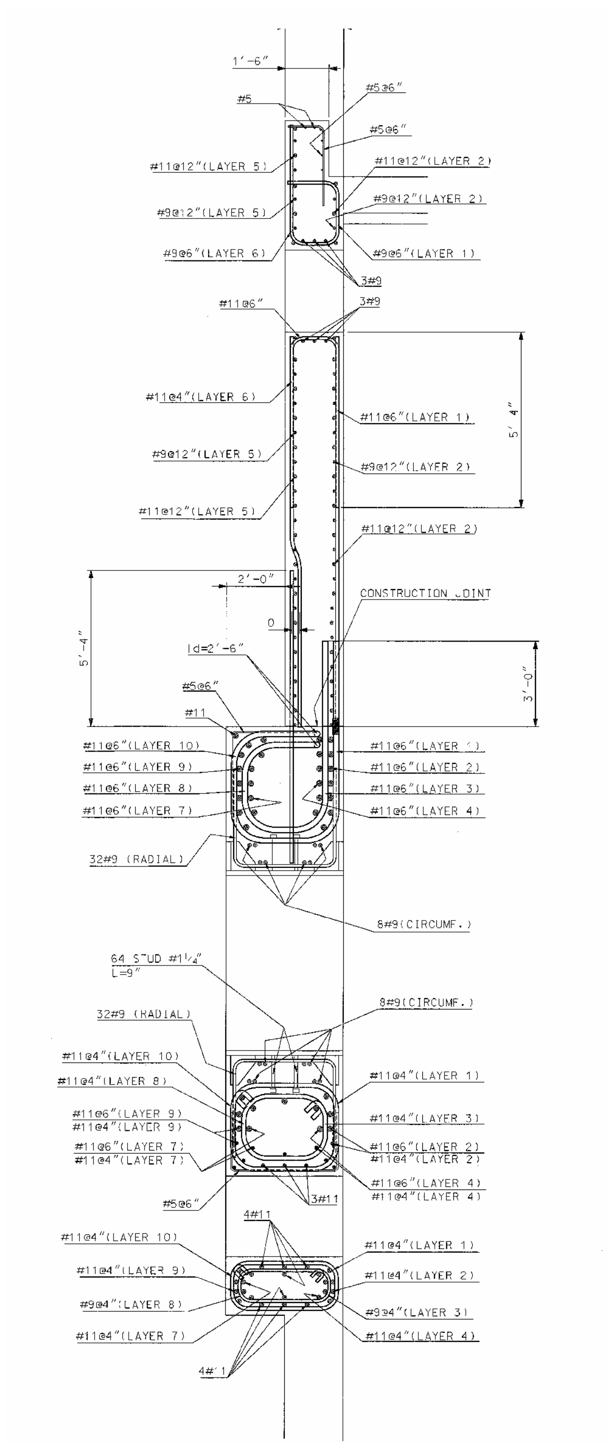


Figure 3H.5-5 (Sheet 3 of 3)

[*Wall 11 at Main Steamline Anchor Section A-A*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

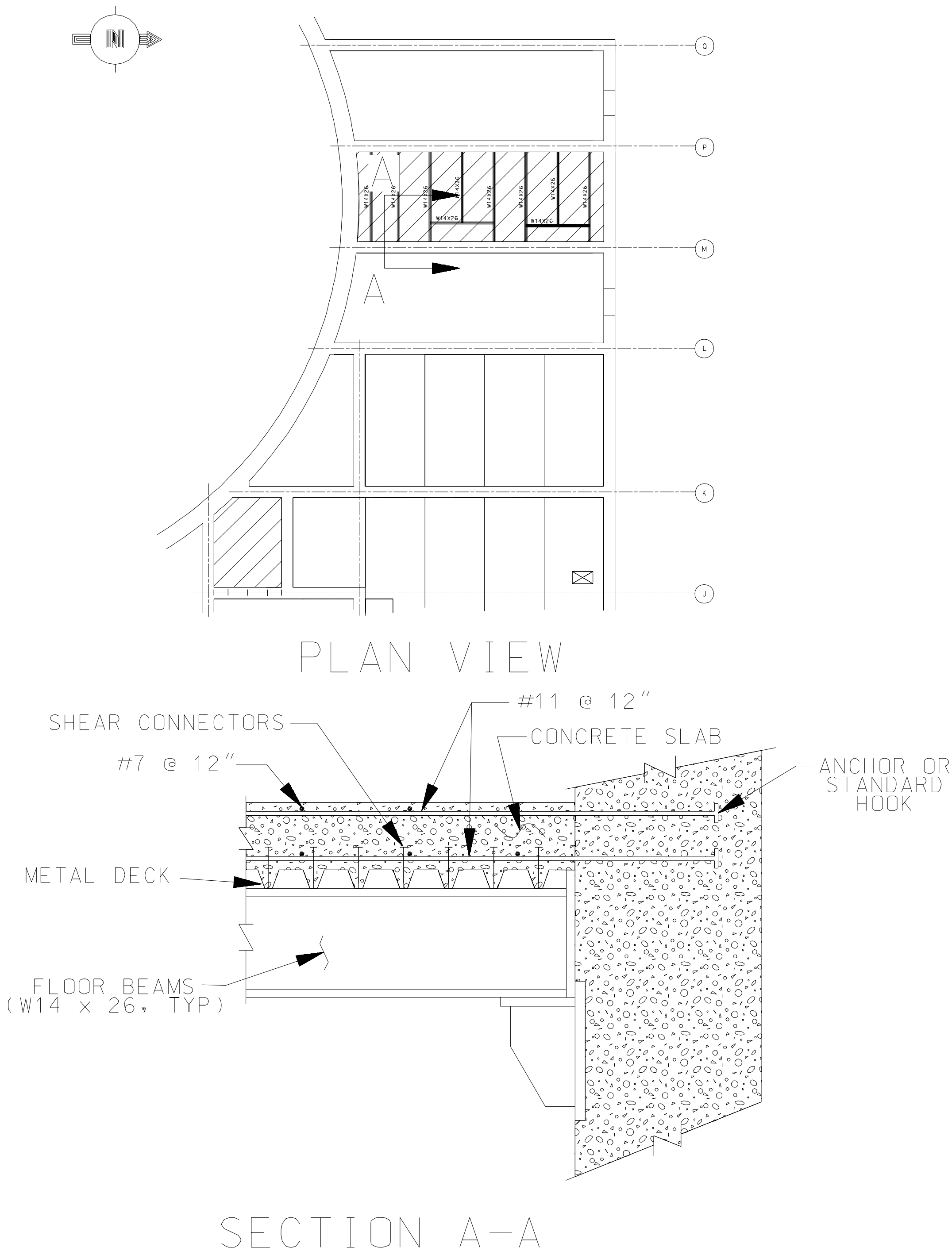


Figure 3H.5-6

***[Auxiliary Building
Typical Composite Floor]****

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

[This page intentionally blank]

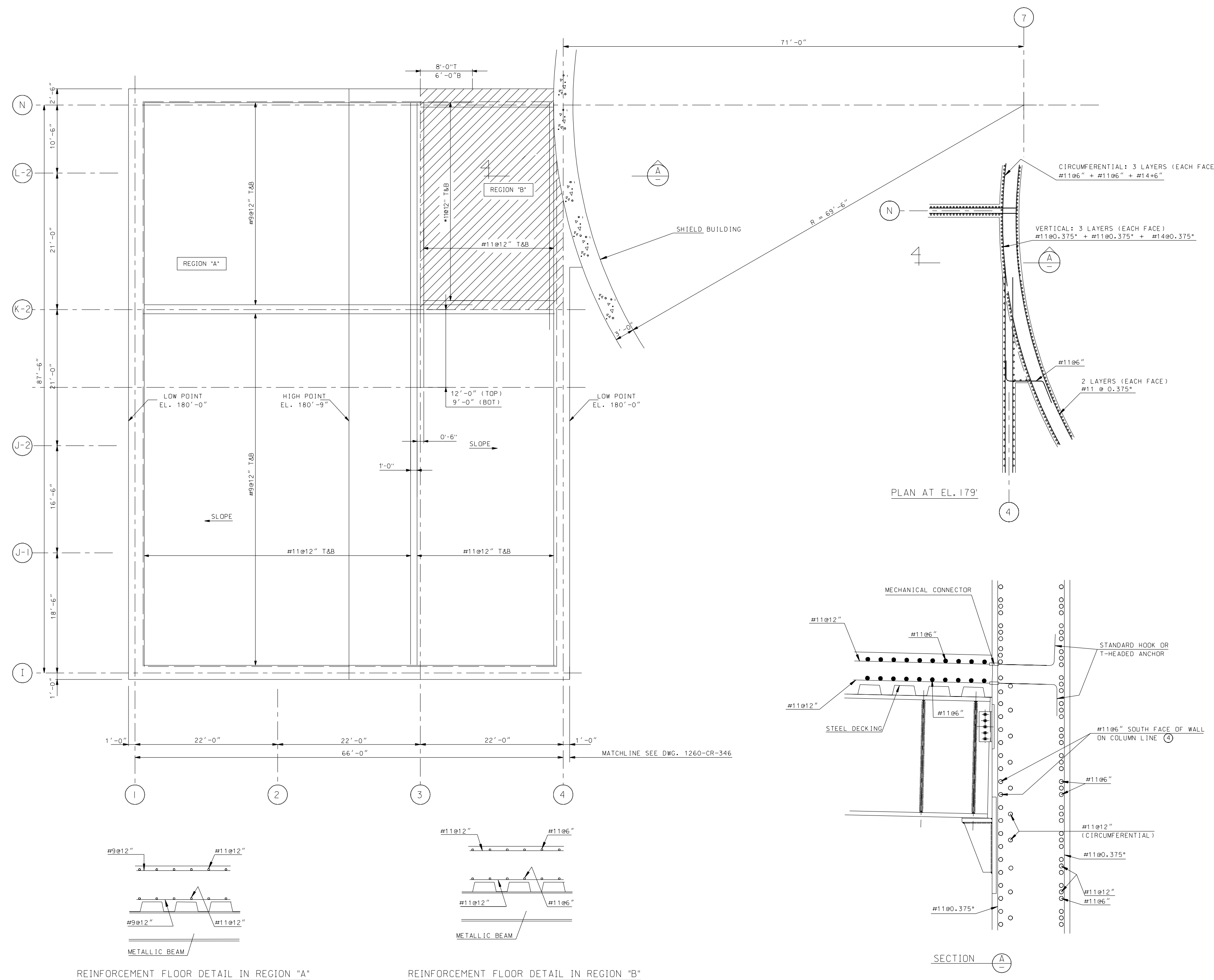


Figure 3H.5-7

[Typical Reinforcement and Connection to Shield Building]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

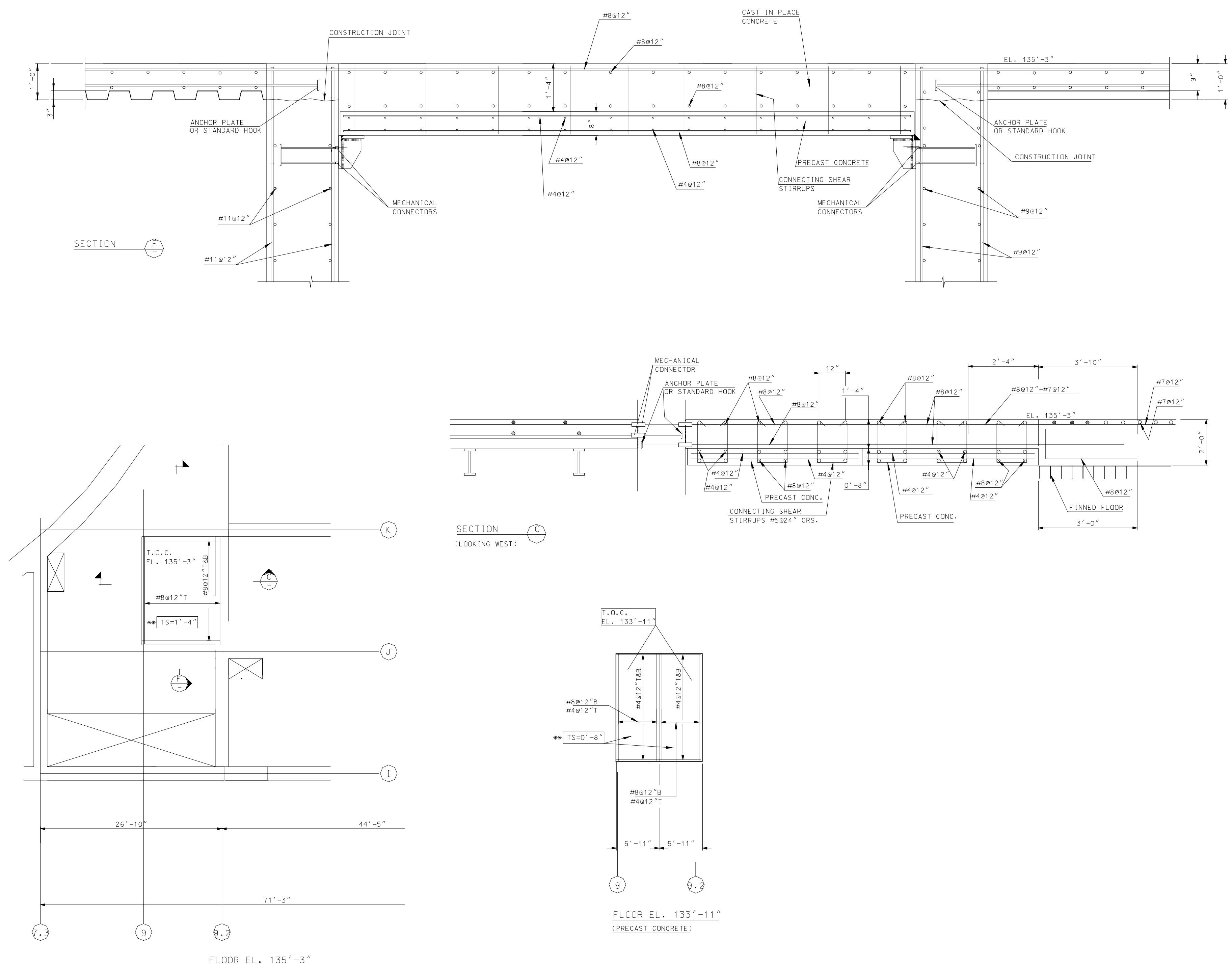


Figure 3H.5-8

[*Auxiliary Building Tagging Room Ceiling*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

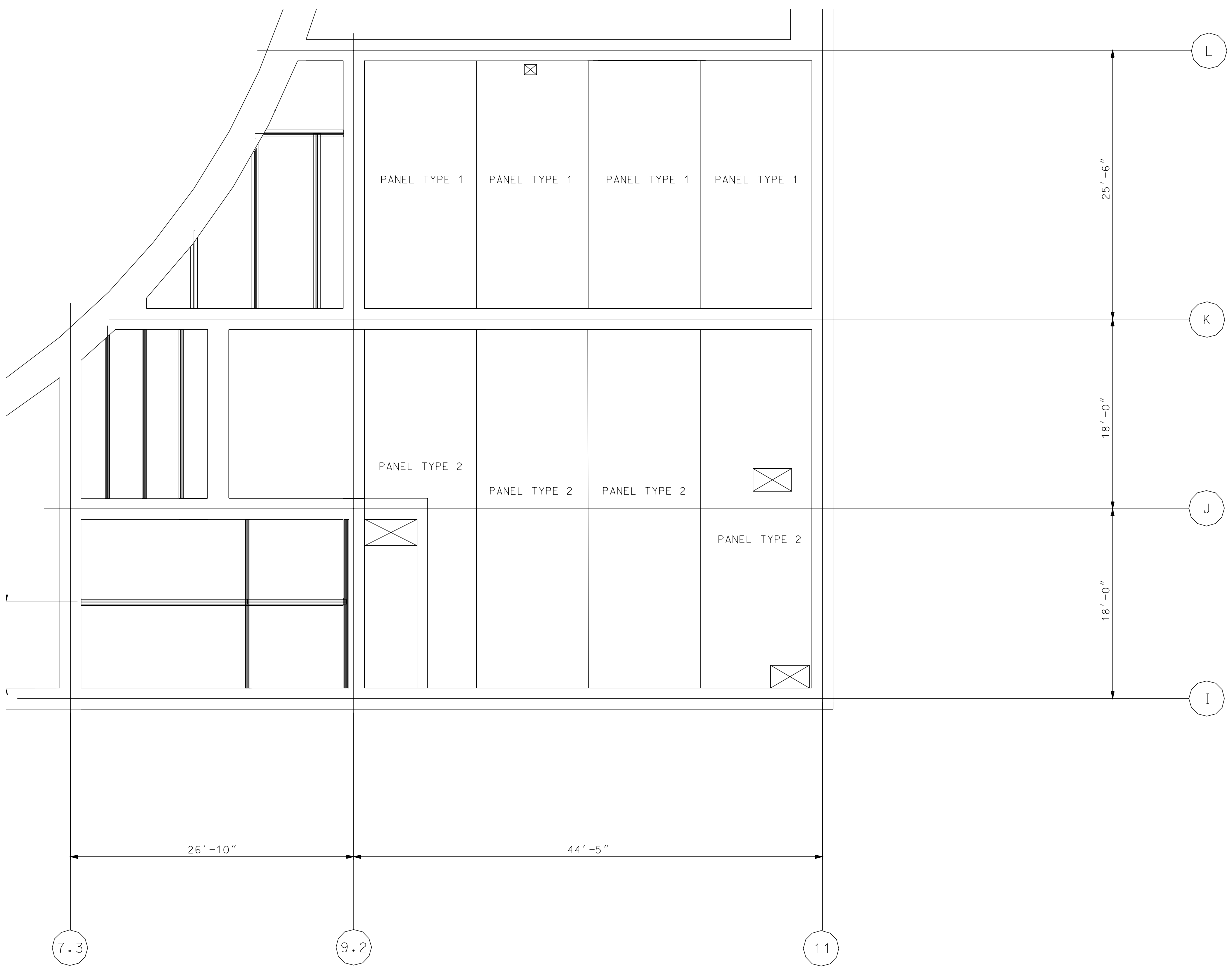


Figure 3H.5-9 (Sheet 1 of 3)

[*Auxiliary Building Finned Floor*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

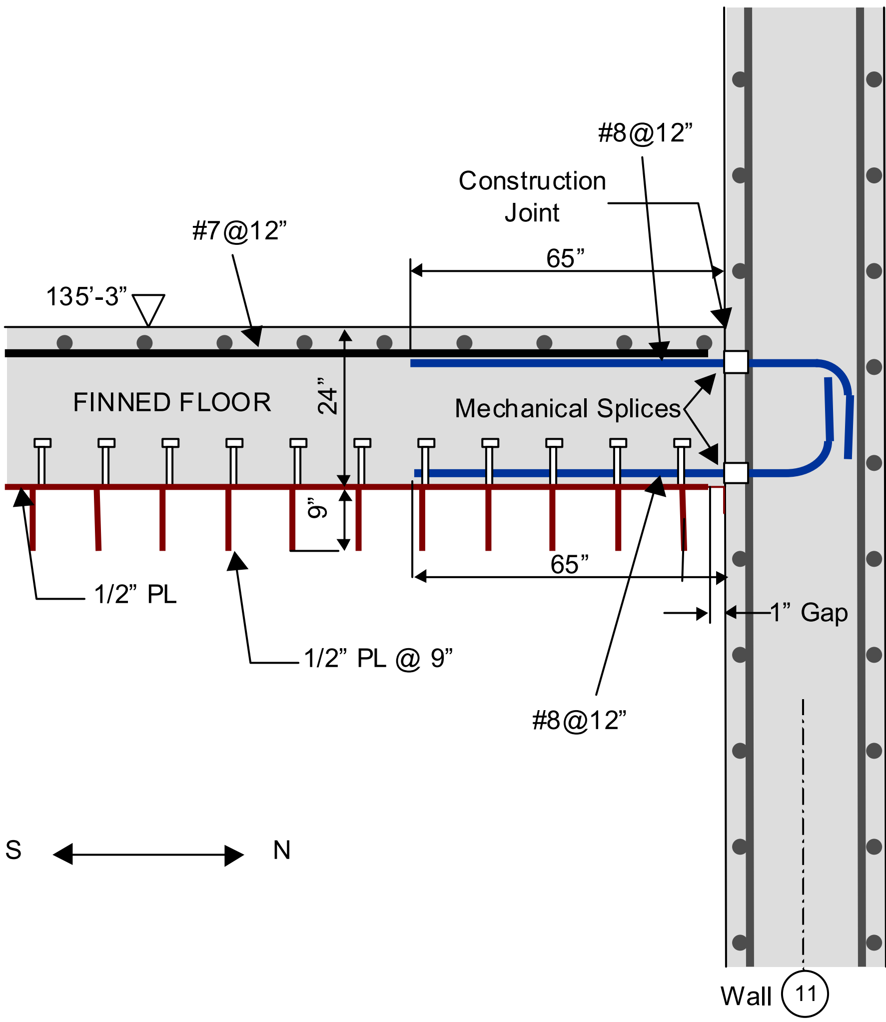


Figure 3H.5-9 (Sheet 2 of 3)

[*Auxiliary Building Finned Floor*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

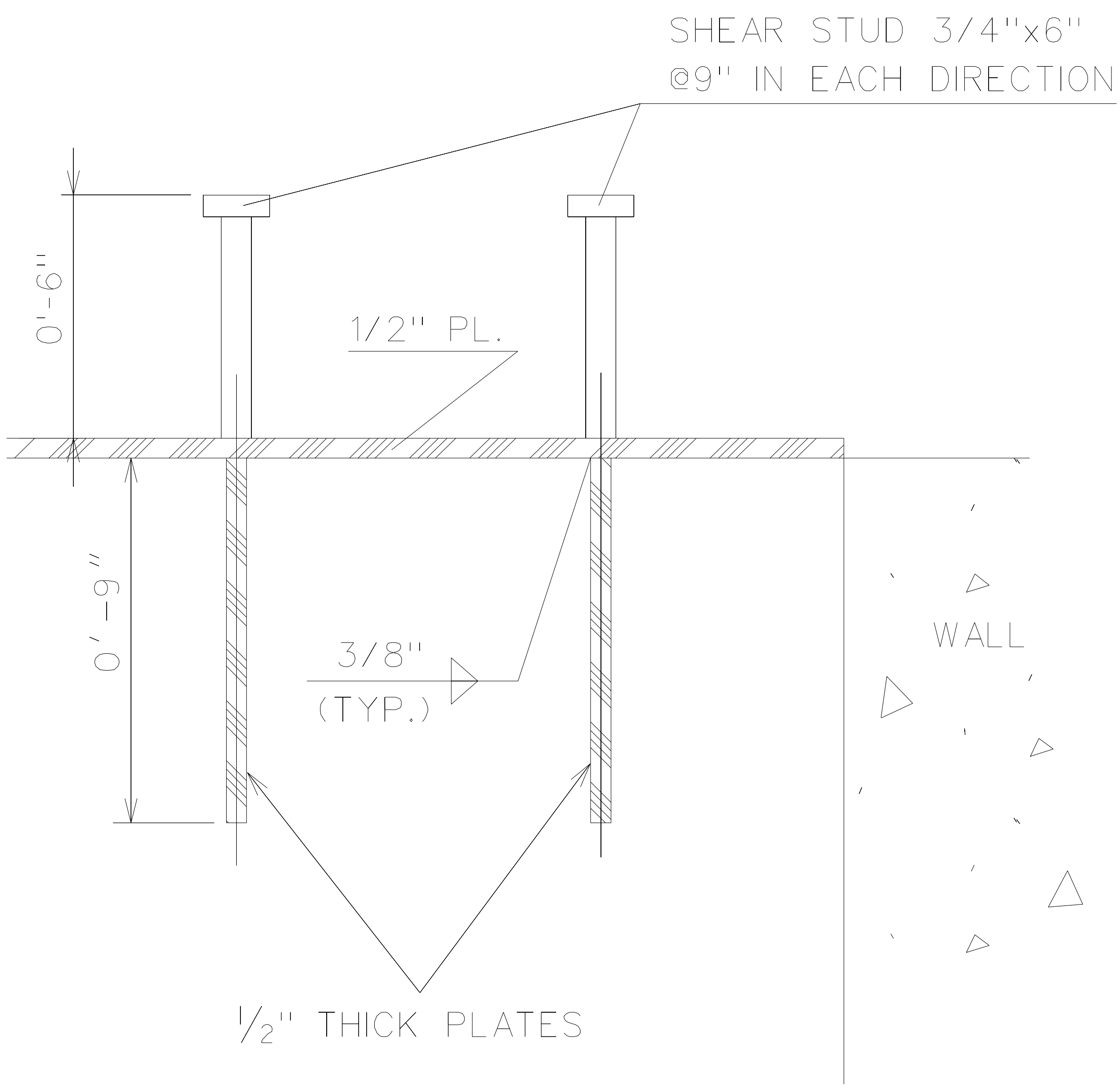


Figure 3H.5-9 (Sheet 3 of 3)

[*Auxiliary Building Finned Floor*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

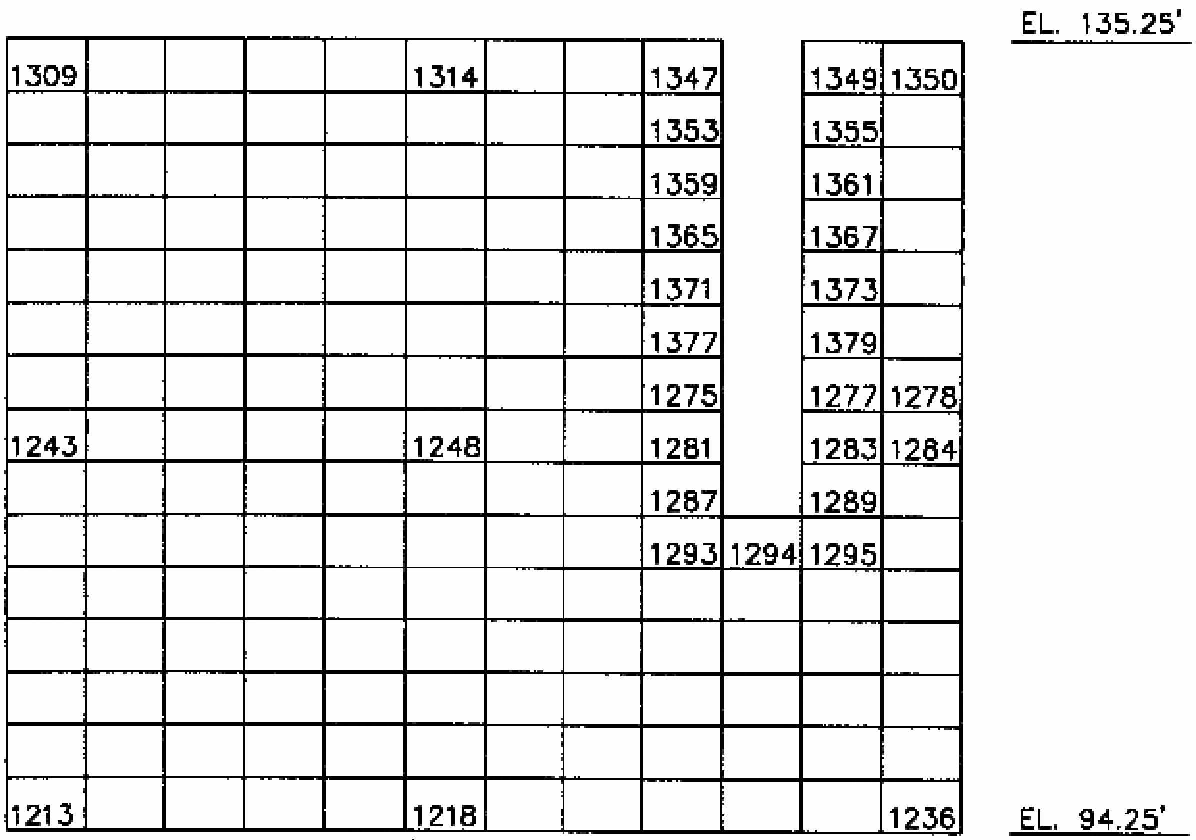


Figure 3H.5-10

[*Spent Fuel Pool Wall Divider Wall Element Locations*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

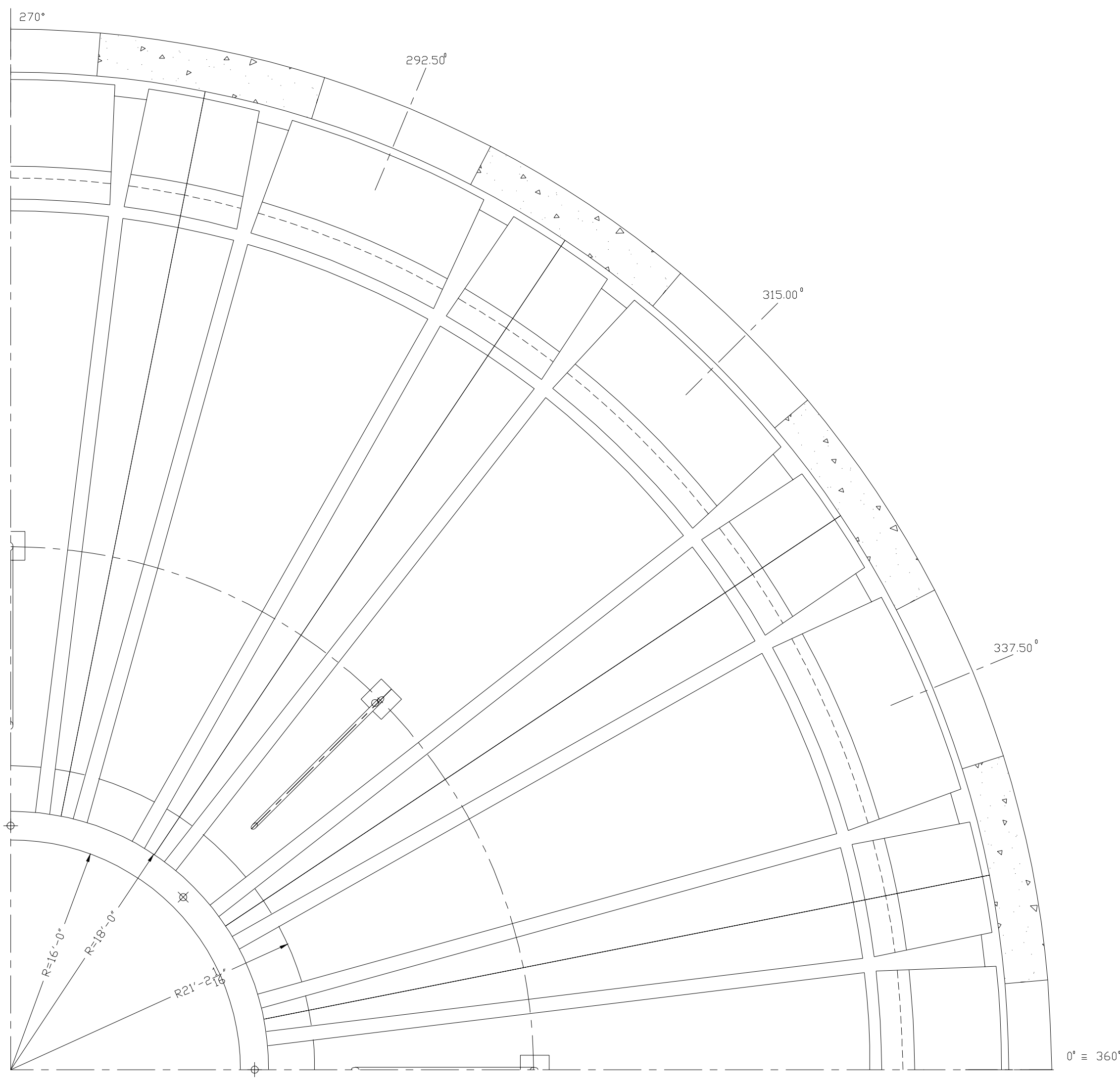


Figure 3H.5-11 (Sheet 1 of 8)

[*Shield Building Roof*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

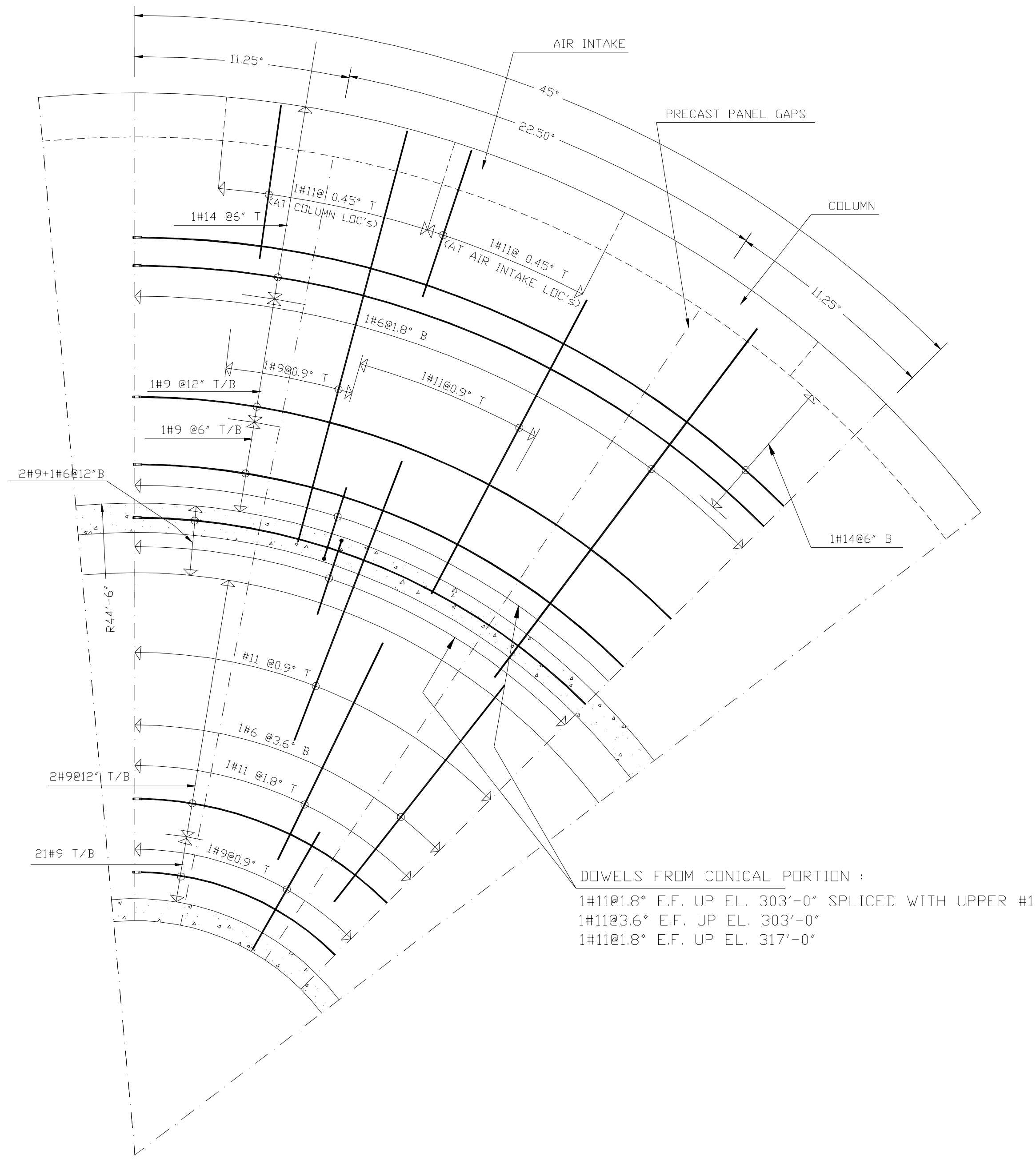


Figure 3H.5-11 (Sheet 2 of 8)

[*Shield Building Roof Typical Reinforcement*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

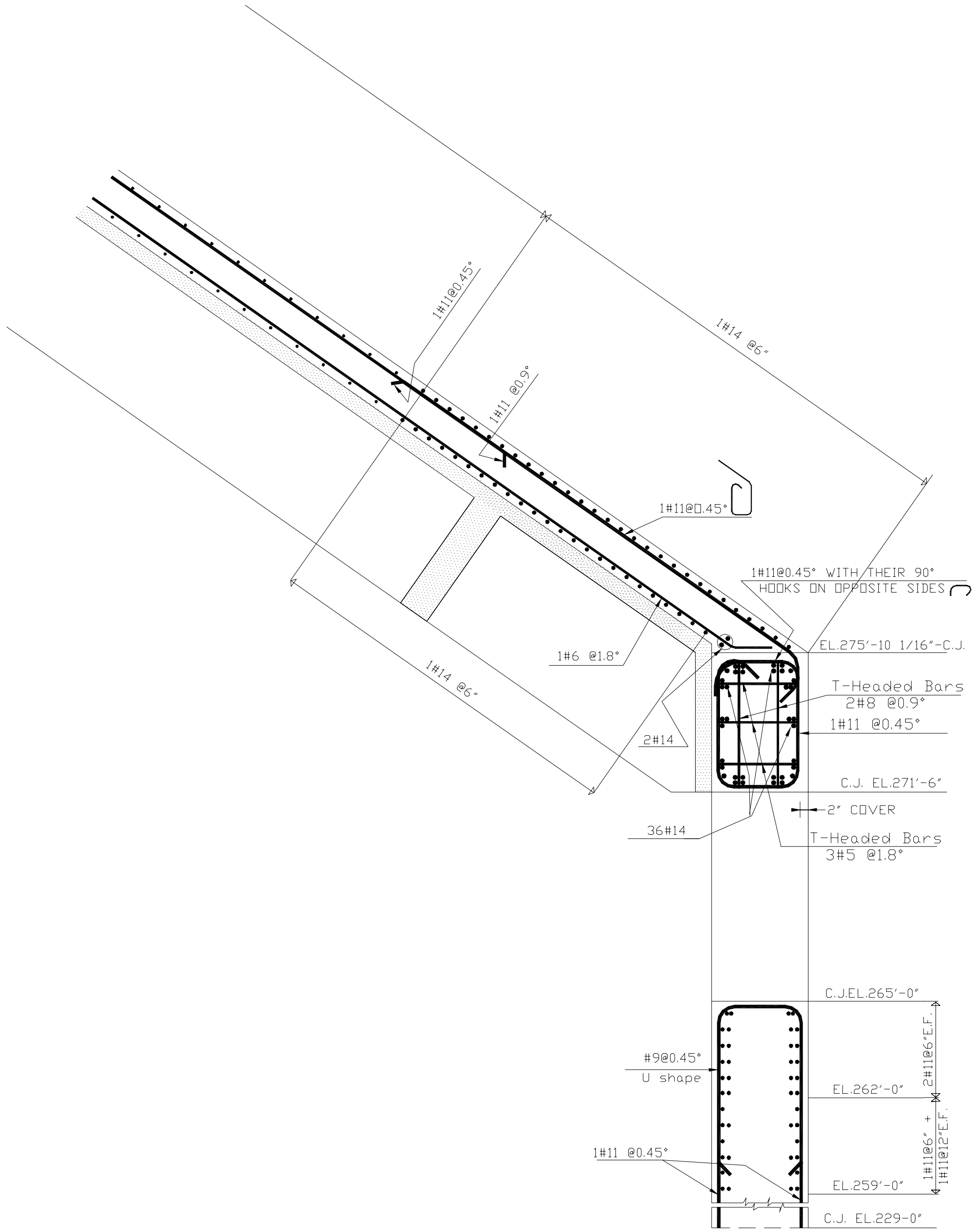


Figure 3H.5-11 (Sheet 3 of 8)

**[*Shield Building Roof
Typical Reinforcement*]***

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

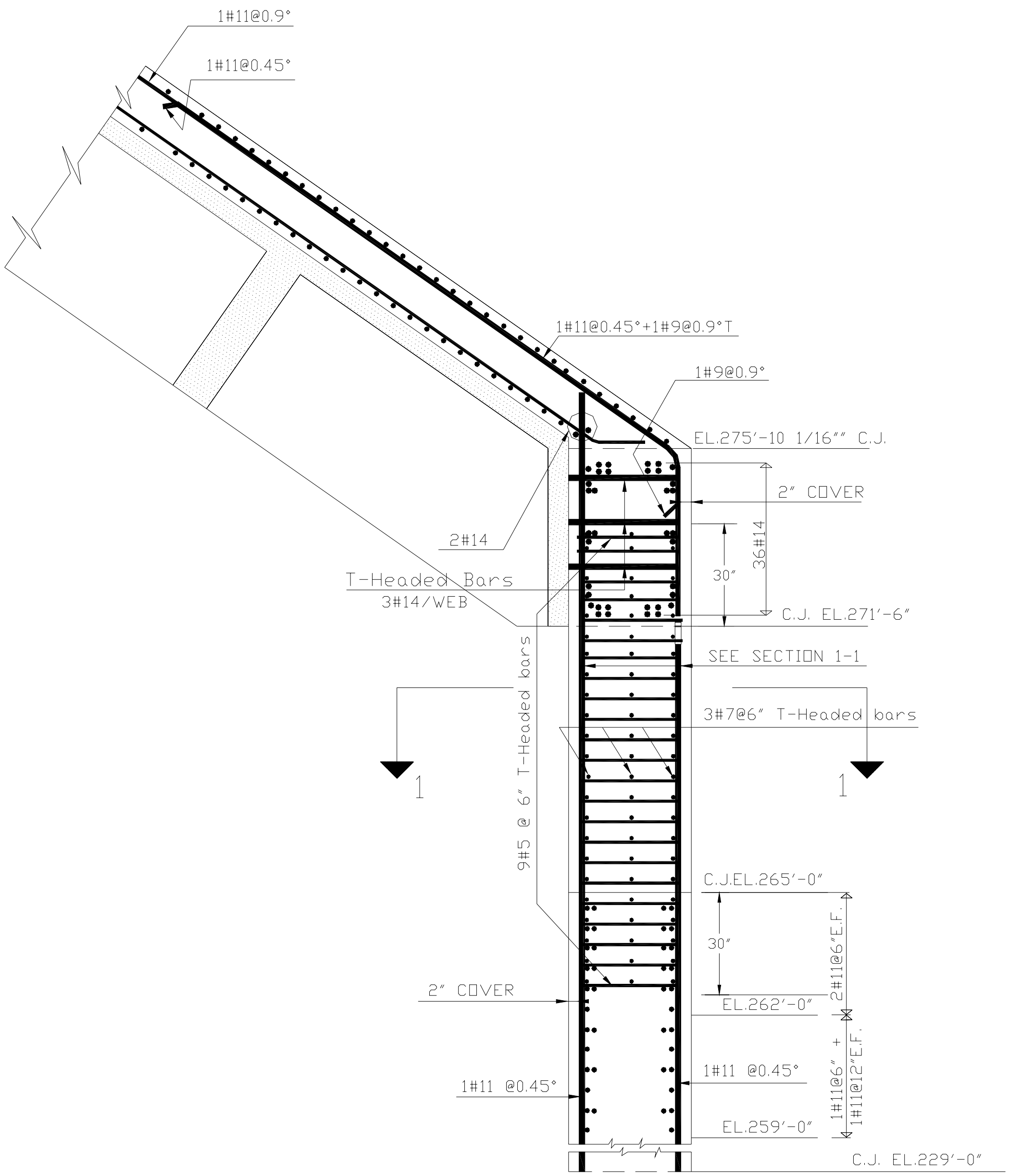


Figure 3H.5-11 (Sheet 4 of 8)

[Shield Building Roof Typical Reinforcement]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

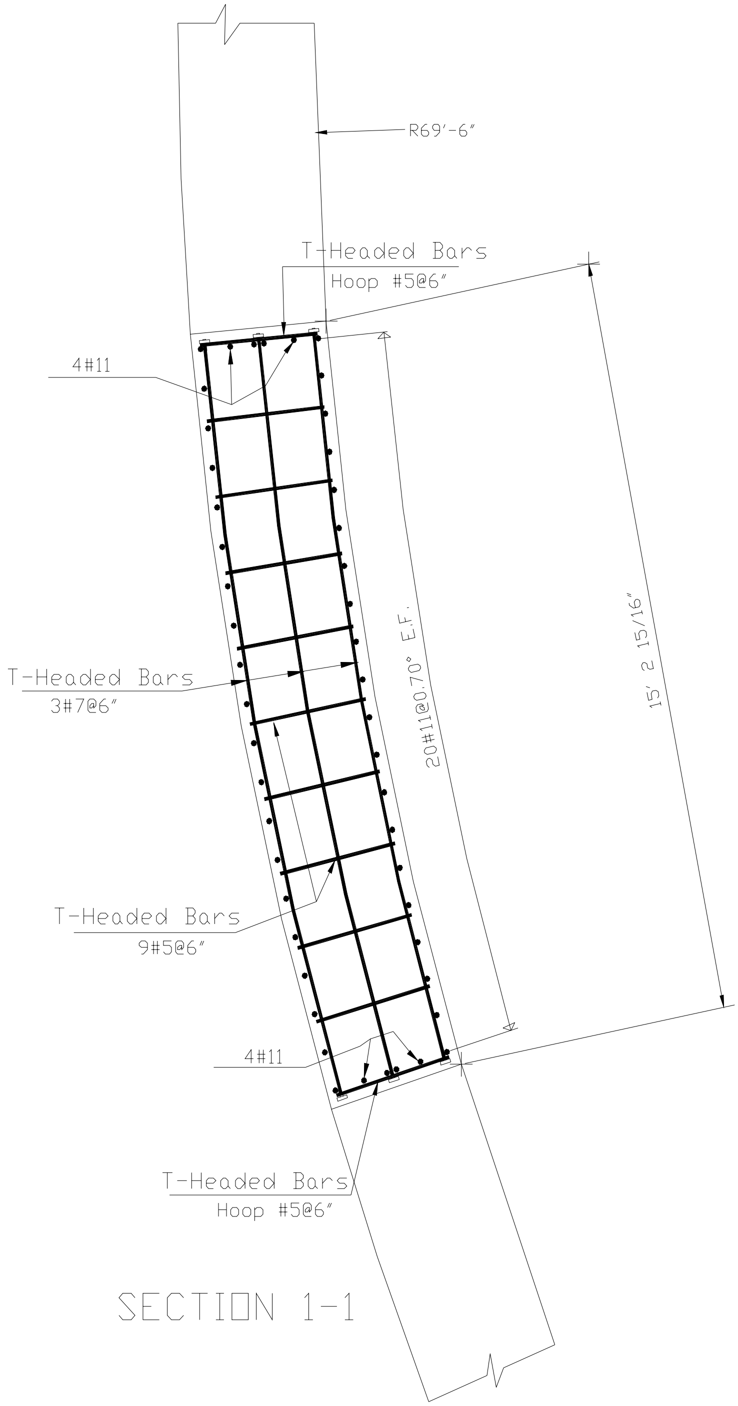


Figure 3H.5-11 (Sheet 5 of 8)

[Shield Building Roof Typical Reinforcement]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

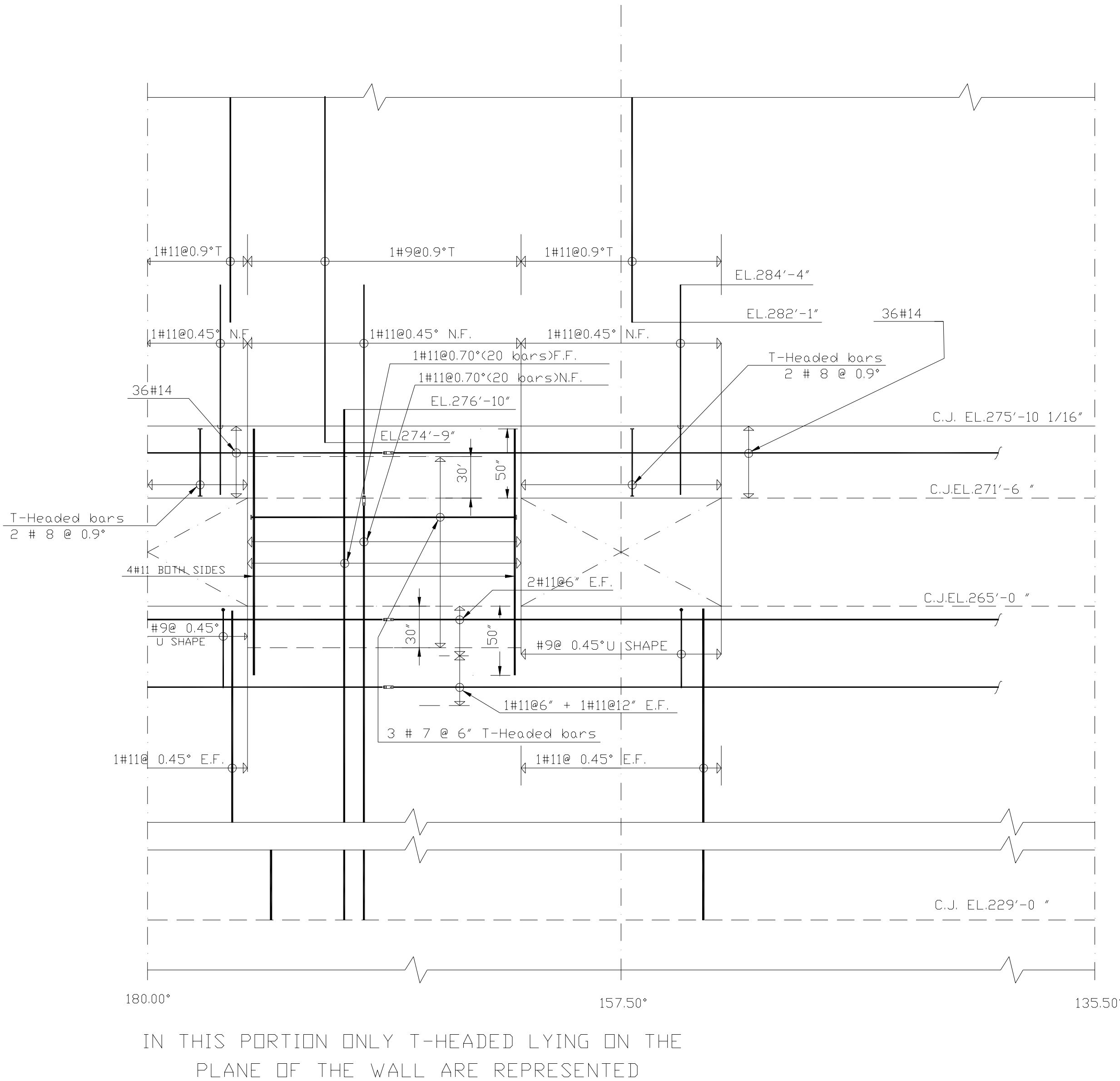


Figure 3H.5-11 (Sheet 6 of 8)

[Shield Building Roof Typical Reinforcement]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

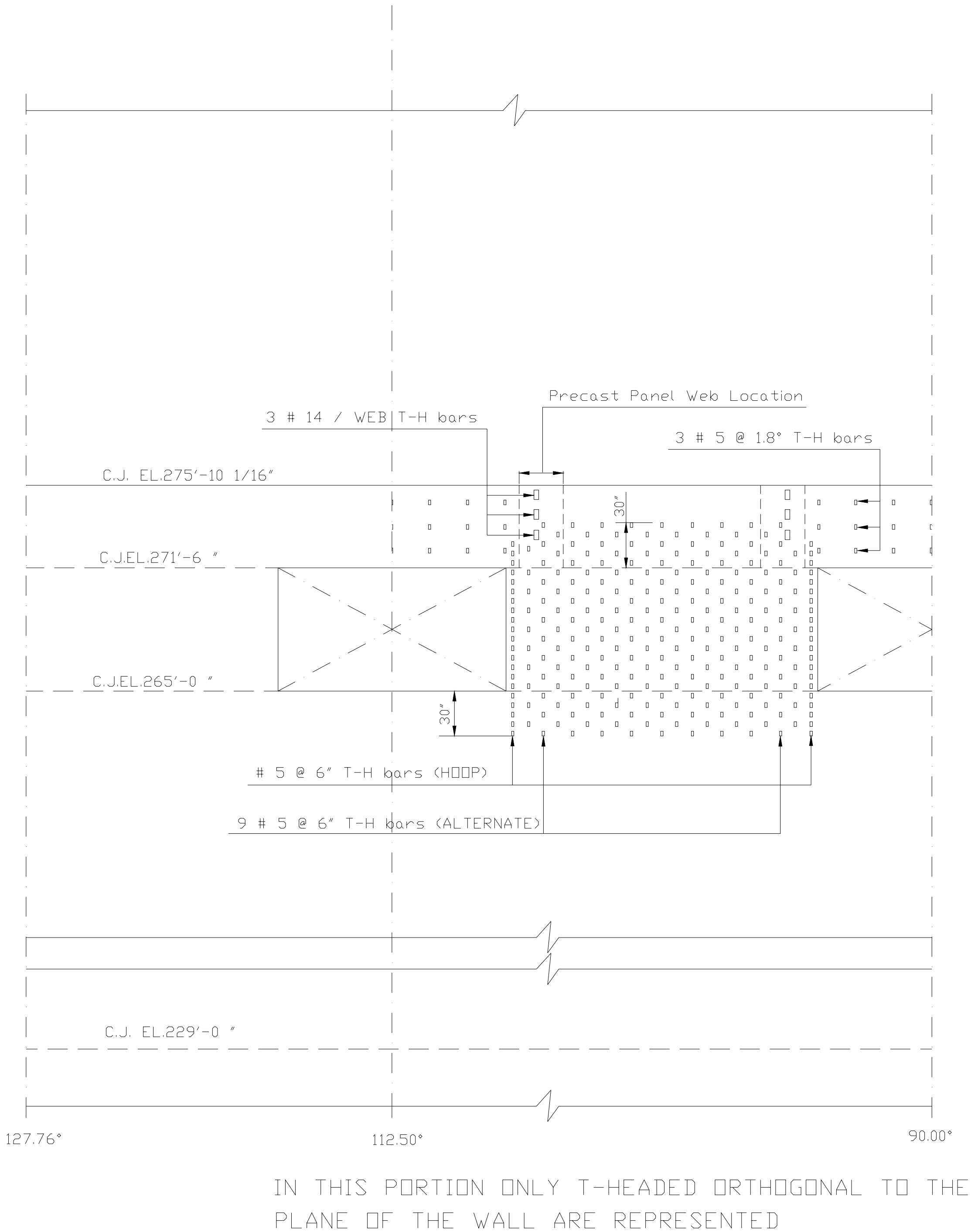


Figure 3H.5-11 (Sheet 7 of 8)

[*Shield Building Roof Typical Reinforcement*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

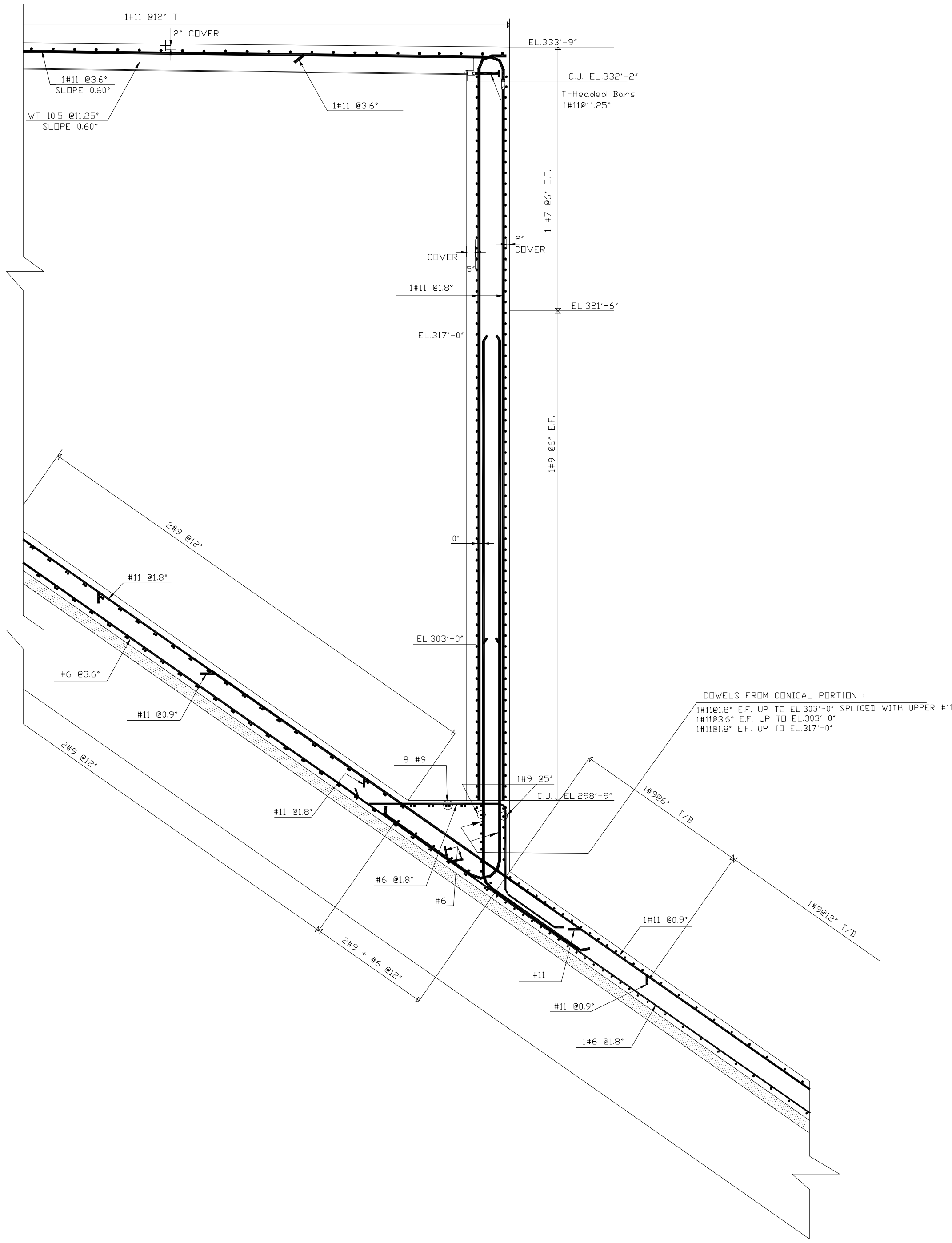


Figure 3H.5-11 (Sheet 8 of 8)

***[Shield Building Roof
Typical Reinforcement]****

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

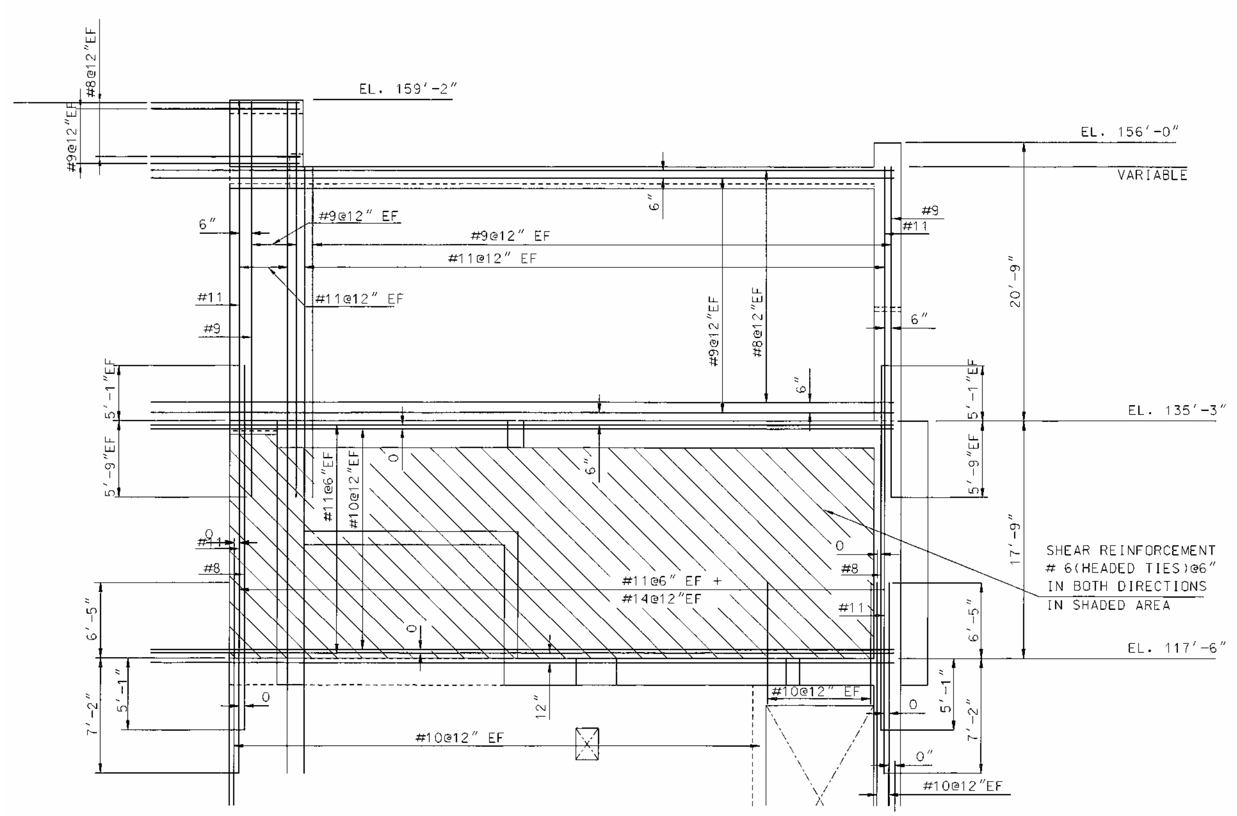


Figure 3H.5-12

[*Typical Reinforcement in Wall L*]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

LIST OF TABLES

LIST OF FIGURES

LIST OF FIGURES (Cont.)

CHAPTER 4

REACTOR

4.1 Summary Description

This chapter describes the mechanical components of the reactor and reactor core, including the fuel rods and fuel assemblies, the nuclear design, and the thermal-hydraulic design.

The reactor contains a matrix of fuel rods assembled into mechanically identical fuel assemblies along with control and structural elements. The assemblies, containing various fuel enrichments, are configured into the core arrangement located and supported by the reactor internals. The reactor internals also direct the flow of the coolant past the fuel rods. The coolant and moderator are light water at a normal operating pressure of 2250 psia. The fuel, internals, and coolant are contained within a heavy walled reactor pressure vessel. An AP1000 fuel assembly consists of 264 fuel rods in a 17x17 square array. The center position in the fuel assembly has a guide thimble that is reserved for in-core instrumentation. The remaining 24 positions in the fuel assembly have guide thimbles. The guide thimbles are joined to the top and bottom nozzles of the fuel assembly and provide the supporting structure for the fuel grids.

The fuel grids consist of an egg-crate arrangement of interlocked straps that maintain lateral spacing between the rods. The grid straps have spring fingers and dimples that grip and support the fuel rods. The intermediate mixing vane grids also have coolant mixing vanes. In addition, there are four intermediate flow mixing (IFM) grids. The IFM grid straps contain support dimples and coolant mixing vanes only. The top and bottom grids do not contain mixing vanes.

The AP1000 fuel assemblies are similar to the 17x17 Robust and 17x17 XL Robust fuel assemblies. The 17x17 Robust fuel assemblies have an active fuel length of 12 feet and three intermediate flow mixing grids in the top mixing vane grid spans. The 17x17 XL Robust fuel assemblies have an active fuel length of 14 feet with no intermediate flow mixing grids. The AP1000 fuel assemblies are the same as the 17x17 XL Robust fuel assemblies except that they have four intermediate flow mixing grids in the top mixing vane grid spans.

There is substantial operating experience with the 17x17 Robust and 17x17 XL Robust fuel assemblies. The 17x17 Robust fuel assemblies are described in References 1, 2 and 3. The 17x17 XL Robust fuel assemblies are described in References 4 and 5.

The XL Robust fuel assembly evolved from the previous VANTAGE+, VANTAGE 5 and VANTAGE 5 HYBRID designs. The XL Robust fuel assembly is based on the substantial design and operating experience with those designs. The design is described and evaluated in References 2, 3, 6 through 10.

A number of proven design features have been incorporated in the AP1000 fuel assembly design. The AP1000 fuel assembly design includes: low pressure drop intermediate grids, four intermediate flow mixing (IFM) grids, a reconstitutable integral clamp top nozzle (ICTN), and extended burnup capability. The bottom nozzle is a debris filter bottom nozzle (DFBN) that

minimizes the potential for fuel damage due to debris in the reactor coolant. The AP1000 fuel assembly design also includes a protective grid for enhanced debris resistance.

The fuel rods consist of enriched uranium, in the form of cylindrical pellets of uranium dioxide, contained in ZIRLO™ (Reference 8) tubing. The tubing is plugged and seal welded at the ends to encapsulate the fuel. An axial blanket comprised of fuel pellets with reduced enrichment may be placed at each end of the enriched fuel pellet stack to reduce the neutron leakage and to improve fuel utilization.

Other types of fuel rods may be used to varying degrees within some fuel assemblies. One type uses an integral fuel burnable absorber (IFBA) containing a thin boride coating on the surface of the fuel pellets. Another type uses fuel pellets containing gadolinium oxide mixed with uranium oxide. The boride-coated fuel pellets and gadolinium oxide/uranium oxide fuel pellets provide a burnable absorber integral to the fuel.

Fuel rods are pressurized internally with helium during fabrication to reduce clad creepdown during operation and thereby prevent clad flattening. The fuel rods in the AP1000 fuel assemblies contain additional gas space below the fuel pellets, compared to the 17x17 Robust, 17x17 XL Robust and other previous fuel assembly designs to allow for increased fission gas production due to high fuel burnups.

Depending on the position of the assembly in the core, the guide thimbles are used for rod cluster control assemblies (RCCAs), gray rod cluster assemblies (GRCAs), neutron source assemblies, or non-integral discrete burnable absorber (BA) assemblies.

For the initial core design, discrete burnable absorbers (BAs) and integral fuel burnable absorbers are used. Discrete burnable absorber designs, integral fuel burnable absorber designs (including both IFBAs and gadolinium oxide/uranium oxide BAs) or combinations may be used in subsequent reloads.

The bottom nozzle is a box-like structure that serves as the lower structural element of the fuel assembly and directs the coolant flow distribution to the assembly. The size of flow passages through the bottom nozzle limits the size of debris that can enter the fuel assembly. The top nozzle assembly serves as the upper structural element of the fuel assembly and provides a partial protective housing for the rod cluster control assembly or other components.

The rod cluster control assemblies consist of 24 absorber rods fastened at the top end to a common hub, or spider assembly. Each absorber rod consists of an alloy of silver-indium-cadmium, which is clad in stainless steel. The rod cluster control assemblies are used to control relatively rapid changes in reactivity and to control the axial power distribution.

The gray rod cluster assemblies consist of 24 rodlets fastened at the top end to a common hub or spider. Geometrically, the gray rod cluster assembly is the same as a rod cluster control assembly except that 20 of the 24 rodlets are fabricated of stainless steel, while the remaining 4 are silver-indium-cadmium with stainless steel clad.

The gray rod cluster assemblies are used in load follow maneuvering. The assemblies provide a mechanical shim reactivity mechanism to minimize the need for changes to the concentration of soluble boron.

The reactor core is cooled and moderated by light water at a pressure of 2250 psia. Soluble boron in the moderator/coolant serves as a neutron absorber. The concentration of boron is varied to control reactivity changes that occur relatively slowly, including the effects of fuel burnup. Burnable absorbers are also employed in the initial cycle to limit the amount of soluble boron required and, thereby maintain the desired negative reactivity coefficients.

The nuclear design analyses establish the core locations for control rods and burnable absorbers. The analyses define design parameters, such as fuel enrichments and boron concentration in the coolant.

The nuclear design establishes that the reactor core and the reactor control system satisfy design criteria, even if the rod cluster control assembly of the highest reactivity worth is in the fully withdrawn position.

The core has inherent stability against diametral and azimuthal power oscillations. Axial power oscillations, which may be induced by load changes, and resultant transient xenon may be suppressed by the use of the rod cluster control assemblies.

The control rod drive mechanisms used to withdraw and insert the rod cluster control assemblies and the gray rod cluster assemblies are described in subsection 3.9.4.

The thermal-hydraulic design analyses establish that adequate heat transfer is provided between the fuel clad and the reactor coolant. The thermal design takes into account local variations in dimensions, power generation, flow distribution, and mixing. The mixing vanes incorporated in the fuel assembly spacer grid design and the fuel assembly intermediate flow mixers induce additional flow mixing between the various flow channels within a fuel assembly, as well as between adjacent assemblies.

The reactor internals direct the flow of coolant to and from the fuel assemblies and are described in subsection 3.9.5.

The performance of the core is monitored by fixed neutron detectors outside the core, fixed neutron detectors within the core, and thermocouples at the outlet of selected fuel assemblies. The ex-core nuclear instrumentation provides input to automatic control functions.

Table 4.1-1 presents a summary of the principal nuclear, thermal-hydraulic, and mechanical design parameters of the AP1000 fuel. A comparison is provided to the fuel design used in AP1000, AP600 and in a licensed Westinghouse-designed plant using XL Robust fuel. For the comparison with a plant containing XL Robust fuel, a 193 fuel assembly plant is used, since no domestic, Westinghouse-designed 157 fuel assembly plants use 17x17 XL Robust fuel.

Table 4.1-2 tabulates the analytical techniques employed in the core design. The design basis must be met using these analytical techniques. Enhancements may be made to these techniques provided that the changes are bounded by NRC-approved methods, models, or criteria. In addition, application of the process described in WCAP-12488-A, (Reference 9) allows the Combined License holder to make fuel mechanical changes. Table 4.1-3 tabulates the mechanical loading conditions considered for the core internals and components. Specific or limiting loads considered for design purposes of the various components are listed as follows: fuel assemblies in subsection 4.2.1.5; neutron absorber rods, gray rods, burnable absorber rods, and neutron source rods, in subsection 4.2.1.6. The dynamic analyses, input forcing functions, and response loadings for the control rod drive system and reactor vessel internals are presented in subsections 3.9.4 and 3.9.5.

4.1.1 Principal Design Requirements

The fuel and rod control rod mechanism are designed so the performance and safety criteria described in Chapter 4 and Chapter 15 are met. [*The mechanical design and physical arrangement of the reactor components, together with the corrective actions of the reactor control, protection, and emergency cooling systems (when applicable) are designed to achieve these criteria, referred to as Principal Design Requirements:*

- *Fuel damage, defined as penetration of the fuel clad, is predicted not to occur during normal operation and anticipated operational transients.*
- *Materials used in the fuel assembly and in-core control components are selected to be compatible in a pressurized water reactor environment.*
- *For normal operation and anticipated transient conditions, the minimum DNBR calculated using the WRB-2M correlation is greater than or equal to 1.14.*
- *Fuel melting will not occur at the overpower limit for Condition I or II events.*
- *The maximum fuel rod cladding temperature following a loss-of-coolant accident is calculated to be less than 2200°F.*
- *For normal operation and anticipated transient conditions, the calculated core average linear power, including densification effects, is less than or equal to 5.71 kw/ft for the initial fuel cycle.*
- *For normal operation and anticipated transient conditions, the calculated total heat flux hot channel factor, F_Q, is less than or equal to 2.60 for the initial fuel cycle.*
- *Calculated rod worths provide sufficient reactivity to account for the power defect from full power to zero power and provide the required shutdown margin, with allowance for the worst stuck rod.*
- *Calculations of the accidental withdrawal of two control banks using the maximum reactivity change rate predict that the peak linear heat rate and DNBR limits are met.*

* NRC Staff approval is required prior to implementing a change in this material; see DCD Introduction Section 3.5.

- *The maximum rod control cluster assembly and gray rod speed (or travel rate) is 45 inches per minute.*

- *The control rod drive mechanisms are hydrotested after manufacture at a minimum of 150 percent of system design pressure.*

- *For the initial fuel cycle, the fuel rod temperature coefficient is calculated to be negative for power operating conditions.*

- *For the initial fuel cycle, the moderator temperature coefficient is calculated to be negative for power operating conditions*.]*

4.1.2 Combined License Information

This section contains no requirement for additional information to be provided in support of Combined License.

4.1.3 References

1. Letter from N. J. Liparulo (Westinghouse) to J. E. Lyons (NRC), "Transmittal of Response to NRC Request for Information on Wolf Creek Fuel Design Modifications," NSD-NRC-97-5189, June 30, 1997.

2. Letter from N. J. Liparulo (Westinghouse) to R. C. Jones (NRC), "Transmittal of Presentation Material for NRC/Westinghouse Fuel Design Change Meeting on April 15, 1996," NSD-NRC-96-4964, April 22, 1996.

3. Letter from Westinghouse to NRC, "Fuel Criteria Evaluation Process Notification for the 17x17 Robust Fuel Assembly with IFM Grid Design," NSD-NRC-98-5796, October 13, 1998.

4. Letter from H. A. Sepp (Westinghouse) to T. E. Collins (NRC), "Notification of FCEP Application for WRB-1 and WRB-2 Applicability to the 17x17 Modified LPD Grid Design for Robust Fuel Assembly Application," NSD-NRC-98-5618, March 25, 1998.

5. Letter from H. A. Sepp (Westinghouse) to T. E. Collins (NRC), "Fuel Criteria Evaluation Process Notification for the Revised Guide Thimble Dashpot Design for the 17x17 XL Robust Fuel Assembly Design," NSD-NRC-98-5722, June 23, 1998.

6. Davidson, S. L., and Kramer, W. R., (Ed.), "Reference Core Report Vantage 5 Fuel Assembly," WCAP-10444-P-A (Proprietary), September 1985 and WCAP-10445-A (Non-Proprietary), December 1983.

7. Davidson, S. L., (Ed.), "VANTAGE 5H Fuel Assembly," Addendum 2-A, WCAP-10444-P-A (Proprietary) and WCAP-10445-NP-A (Non-Proprietary), February 1989.

* NRC Staff approval is required prior to implementing a change in this material; see DCD Introduction Section 3.5.

8. Davidson, S. L., and Nuhfer, D. L., (Ed.), "VANTAGE+ Fuel Assembly Reference Core Report," WCAP-12610-P-A (Proprietary) and WCAP-14342-A (Non-Proprietary), April 1995.

[*9. Davidson, S. L. (Ed.), "Fuel Criteria Evaluation Process," WCAP-12488-A (Proprietary) and WCAP-14204-A (Non-Proprietary), October 1994.*]*

10. NTD-NRC-94-4275 Westinghouse's Interpretation of Staff's Position on Extended Burnup, August 29, 1994.

* NRC Staff approval is required prior to implementing a change in this material; see DCD Introduction Section 3.5.

Table 4.1-1 (Sheet 1 of 3)

REACTOR DESIGN COMPARISON TABLE

Thermal and Hydraulic Design Parameters	AP1000	AP600	Typical XL Plant
Reactor core heat output (MWt)	3400	1933	3800
Reactor core heat output (10^6 Btu/hr)	11,601	6596	12,969
Heat generated in fuel (%)	97.4	97.4	97.4
System pressure, nominal (psia)	2250	2250	2250
System pressure, minimum steady-state (psia)	2190	2200	2204
Minimum departure from nuclear boiling (DNBR) for design transients Typical flow channel Thimble (cold wall) flow channel	 >1.25[(d)], >1.22[(d)] >1.25[(d)], >1.21[(d)]	 >1.23 >1.22	 >1.26 >1.24
Departure from nucleate boiling (DNB) correlation[(b)]	WRB-2M[(b)]	WRB-2	WRB-1[(a)]
Coolant Flow[(c)]			
Total vessel thermal design flow rate (10^6 lbm/hr) Effective flow rate for heat transfer (10^6 lbm/hr) Effective flow area for heat transfer (ft^2) Average velocity along fuel rods (ft/s) Average mass velocity (10^6 lbm/hr-ft^2)	113.5 106.8 41.5 15.9 2.41	72.9 66.3 38.5 10.6 1.72	145.0 132.7 51.1 16.6 2.60
Coolant Temperature[(c)(e)]			
Nominal inlet (°F) Average rise in vessel (°F) Average rise in core (°F) Average in core (°F) Average in vessel (°F)	535.0 77.2 81.4 578.1 573.6	532.8 69.6 75.8 572.6 567.6	561.2 63.6 68.7 597.8 593.0
Heat Transfer			
Active heat transfer surface area (ft^2) Avg. heat flux (BTU/hr-ft^2) Maximum heat flux for normal operation (BTU/hr-ft^2)[(f)] Average linear power (kW/ft)[(g)] Peak linear power for normal operation (kW/ft)[(f)(g)] Peak linear power (kW/ft)[(f)(h)] (Resulting from overpower transients/operator errors, assuming a maximum overpower of 118%)	56,700 199,300 518,200 5.72 14.9 ≤22.45	44,884 143,000 372,226 4.11 10.7 22.5	69,700 181,200 489,200 5.20 14.0 ≤22.45

Table 4.1-1 (Sheet 2 of 3)

REACTOR DESIGN COMPARISON TABLE

Thermal and Hydraulic Design Parameters	AP1000	AP600	Typical XL Plant
Heat flux hot channel factor (F_Q)	2.60	2.60	2.70
Peak fuel center line temperature (°F) (For prevention of center-line melt)	4700	4700	4700
Fuel assembly design	17x17 XL Robust Fuel	17x17	17x17 XL Robust Fuel/ No IFM
Number of fuel assemblies	157	145	193
Uranium dioxide rods per assembly	264	264	264
Rod pitch (in.)	0.496	0.496	0.496
Overall dimensions (in.)	8.426 x 8.426	8.426 x 8.426	8.426 x 8.426
Fuel weight, as uranium dioxide (lb)	211,588	167,360	261,000
Clad weight (lb)	43,105	35,555	63,200
Number of grids per assembly Top and bottom - (Ni-Cr-Fe Alloy 718) Intermediate Intermediate flow mixing	 2[(i)] 8 ZIRLO™ 4 ZIRLO™	 2[(i)] 7 Zircaloy-4 or 7 ZIRLO™ 4 Zircaloy-4 or 5 ZIRLO™	 2 8 ZIRLO™ 0
Loading technique, first cycle	3 region nonuniform	3 region nonuniform	3 region nonuniform
Fuel Rods			
Number	41,448	38,280	50,952
Outside diameter (in.)	0.374	0.374	0.374
Diametral gap (non-IFBA) (in.)	0.0065	0.0065	0.0065
Clad thickness (in.)	0.0225	0.0225	0.0225
Clad material	ZIRLO™	Zircaloy-4 or ZIRLO™	Zircaloy-4/ ZIRLO™
Fuel Pellets			
Material	UO_2 sintered	UO_2 sintered	UO_2 sintered
Density (% of theoretical)	95.5	95	95
Diameter (in.)	0.3225	0.3225	0.3225
Length (in.)	0.387	0.387	0.387

Table 4.1-1 (Sheet 3 of 3)

REACTOR DESIGN COMPARISON TABLE

Rod Cluster Control Assemblies	**AP1000**	**AP600**	**Typical XL Plant**
Neutron Absorber			
RCCA GRCA	24 Ag-In-Cd rodlets 20 304 SS rodlets 4 Ag-In-Cd rodlets	24 Ag-In-Cd rodlets 20 304 SS rodlets 4 Ag-In-Cd rodlets	24 Hafnium or Ag-In-Cd
Cladding material	Type 304 SS, cold-worked	Type 304 SS, cold-worked	Type 304 SS, cold-worked
Clad thickness, (Ag-In-Cd)	0.0185	0.0185	0.0185
Number of clusters	53 RCCAs 16 GRCAs	45 RCCAs 16 GRCAs	57 RCCAs 0 GRCAs
Core Structure			
Core barrel, ID/OD (in.)	133.75/137.75	133.75/137.75	148.0/152.5
Thermal shield	None	None	Neutron Panel
Baffle thickness (in.)	Core Shroud	Radial reflector	0.875
Structure Characteristics			
Core diameter, equivalent (in.)	119.7	115.0	132.7
Core height, cold, active fuel (in.)	168.0	144.0	168.0
Fuel Enrichment First Cycle (Weight Percent)			
Region 1	2.35	1.90	Typical
Region 2	3.40	2.80	3.8 to 4.4
Region 3	4.45	3.70	(5.0 Max)

Notes:

a. WRB-2M will be used in future reloads
b. See subsection 4.4.2.2.1 for the use of the W-3, WRB-2 and WRB-2M correlations
c. Flow rates and temperatures are based on 10 percent steam generator tube plugging for the AP600 and AP1000 designs
d. 1.25 applies to core and axial offset limits; 1.22 and 1.21 apply to all other RTDP transients
e. Coolant temperatures based on thermal design flow (for AP600 and AP1000)
f. Based on F_Q of 2.60 for AP600 and AP1000
g. Based on densified active fuel length
h. See subsection 4.3.2.2.6
i. The top grid may be fabricated of either nickel-chromium-iron Alloy 718 or ZIRLO™

Table 4.1-2 (Sheet 1 of 2)

ANALYTICAL TECHNIQUES IN CORE DESIGN

Analysis	Technique	Computer Code	Subsection Referenced
Mechanical design of core internals loads, deflections, and stress analysis	Static and dynamic modeling	BLOWDOWN code, FORCE, finite element structural analysis code, and others	3.7.2.1 3.9.2 3.9.3
Fuel rod design Fuel performance characteristics (such as, temperature, internal pressure, and clad stress)	Semi-empirical thermal model of fuel rod with considerations such as fuel density changes, heat transfer, and fission gas release.	Westinghouse fuel rod design model	4.2.1.1 4.2.3.2 4.2.3.3 4.3.3.1 4.4.2.11
Nuclear design Cross-sections and group constants	Microscopic data; macroscopic constants for homogenized core regions	Modified ENDF/B library with PHOENIX-P	4.3.3.2
X-Y and X-Y-Z power distributions, fuel depletion, critical boron concentrations, X-Y and X-Y-Z xenon distributions, reactivity coefficients	2-group diffusion theory, 2-group nodal theory	ANC (2-D or 3-D)	4.3.3.3
Axial power distributions, control rod worths, and axial xenon distribution	1-D, 2-group diffusion theory	APOLLO	4.3.3.3
Fuel rod power	Integral transport theory	LASER	4.3.3.1
Effective resonance temperature	Monte Carlo weighing function	REPAD	4.3.3.1
Criticality of reactor and fuel assemblies	3-D, Monte Carlo theory	AMPX system of codes, KENO-Va	4.3.2.6
Vessel irradiation	Multigroup spatial dependent transport theory	DOT	4.3.2.8
Thermal-hydraulic design steady state	Subchannel analysis of local fluid conditions in rod bundles, including inertial and cross-flow resistance terms; solution progresses from core-wide to hot assembly to hot channel.	VIPRE-01	4.4.4.5.2

Table 4.1-2 (Sheet 2 of 2)

ANALYTICAL TECHNIQUES IN CORE DESIGN

Analysis	Technique	Computer Code	Subsection Referenced
Transient departure from nucleate boiling	Subchannel analysis of local fluid conditions in rod bundles during transients by including accumulation terms in conservation equations; solution progresses from core-wide to hot assembly to hot channel.	VIPRE-01	4.4.4.5.4

Table 4.1-3

DESIGN LOADING CONDITIONS FOR REACTOR CORE COMPONENTS

- Fuel assembly weight and core component weights (burnable absorbers, sources, RCCA, GRCA)
- Fuel assembly spring forces and core component spring forces
- Internals weight
- Control rod trip (equivalent static load)
- Differential pressure
- Spring preloads
- Coolant flow forces (static)
- Temperature gradients
- Thermal expansion
- Interference between components
- Vibration (mechanically or hydraulically induced)
- Operational transients listed in Table 3.9.1-1
- Pump overspeed
- Seismic loads (safe shutdown earthquake)
- Blowdown forces (due to pipe rupture)

4.2 Fuel System Design

The plant conditions for design are divided into four categories.

- Condition I - normal operation and operational transients
- Condition II - events of moderate frequency
- Condition III - infrequent incidents
- Condition IV - limiting faults

Chapter 15 describes bases and plant operation and events involving each condition.

The reactor is designed so that its components meet the following performance and safety criteria:

- The mechanical design and physical arrangement of the reactor core components, together with corrective actions of the reactor control, protection, and emergency cooling systems (when applicable) provide that:

  – Fuel damage, that is, breach of fuel rod clad pressure boundary, is not expected during Condition I and Condition II events. A very small amount of fuel damage may occur. This is within the capability of the plant cleanup system and is consistent with the plant design bases.

  – The reactor can be brought to a safe state following a Condition III event with only a small fraction of fuel rods damaged. The fraction of fuel rods damaged must be limited to meet the dose guidelines of 10 CFR 100 although sufficient fuel damage might occur to preclude immediate resumption of operation.

  – The reactor can be brought to a safe state and the core kept subcritical with acceptable heat transfer geometry following transients arising from Condition IV events.

- The fuel assemblies are designed to withstand non-operational loads induced during shipping, handling, and core loading without exceeding the criteria of subsection 4.2.1.5.1.

- The fuel assemblies are designed to accept control rod insertions to provide the required reactivity control for power operations and reactivity shutdown conditions.

- The fuel assemblies have provisions for the insertion of in-core instrumentation.

- The reactor vessel and internals, in conjunction with the fuel assembly structure, directs reactor coolant through the core. Because of the resulting flow distribution and bypass flow, the heat transfer performance requirements are met for the modes of operation.

The following subsection provides the fuel system design bases and design limits. It is consistent with the criteria of the Standard Review Plan, Section 4.2.

Consistent with the growth in technology, Westinghouse modifies fuel system designs. These modifications utilize NRC approved methods. [*A set of design fuel criteria to be satisfied by new fuel designs was issued to the NRC in WCAP-12488-A (Reference 1)*]* and also presented below in subsection 4.2.1.

4.2.1 Design Basis

The fuel rod and fuel assembly design bases are established to satisfy the general performance and safety criteria presented in Section 4.2 of the Standard Review Plan. [*The design bases and acceptance limits used by Westinghouse are also described in the Westinghouse Fuel Criteria Evaluation Process, WCAP-12488-A (Reference 1).*]*

The fuel rods are designed to satisfy the fuel rod design criteria for rod burnup levels up to the design discharge burnup using the extended burnup design methods described in the Extended Burnup Evaluation report, WCAP-10125-P-A (Reference 2).

The AP1000 fuel rod design considers effects such as fuel density changes, fission gas release, clad creep, and other physical properties which vary with burnup. The integrity of the fuel rods is provided by designing to prevent excessive fuel temperatures as discussed in subsection 4.2.1.2.1; excessive internal rod gas pressures due to fission gas releases as discussed in subsections 4.2.1.3.1 and 4.2.1.3.2; and excessive cladding stresses, strains, and strain fatigue, as discussed in subsections 4.2.1.1.2 and 4.2.1.1.3. The fuel rods are designed so that the conservative design bases of the following events envelope the lifetime operating conditions of the fuel. For each design basis, the performance of the limiting fuel rod, with appropriate consideration for uncertainties, does not exceed the limits specified by the design basis. The detailed fuel rod design also establishes such parameters as pellet size and density, clad/pellet diametral gap, gas plenum size, and helium pre-pressurization level.

Integrity of the fuel assembly structure is provided by setting limits on stresses and deformations due to various loads and by preventing the assembly structure from interfering with the functioning of other components. Three types of loads are considered:

- Non-operational loads, such as those due to shipping and handling
- Normal and abnormal loads, which are defined for Conditions I and II
- Abnormal loads, which are defined for Conditions III and IV

The design bases for the in-core control components are described in subsection 4.2.1.6.

4.2.1.1 Cladding

4.2.1.1.1 Mechanical Properties

The ZIRLO™ cladding material combines neutron economy (low absorption cross-section); high corrosion resistance to coolant, fuel, and fission products; and high strength and ductility at operating temperatures. ZIRLO™ is an advanced zirconium based alloy that has the same or similar properties and advantages as Zircaloy-4 and was developed to support extended fuel

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

burnup. WCAP-12610-P-A (Reference 5) provides a discussion of chemical and mechanical properties of the ZIRLO™ cladding material and a comparison to Zircaloy-4.

4.2.1.1.2 Stress-Strain Limits

Clad Stress

[*The volume average effective stress calculated with the Von Mises equation (considering interference due to uniform cylindrical pellet-clad contact, caused by pellet thermal expansion, pellet swelling and uniform clad creep, and pressure differences) is less than the 0.2 percent offset yield stress with due consideration to temperature and irradiation effects for Condition I and II events, WCAP-12488-A (Reference 1).*]* While the clad has some capability for accommodating plastic strain, the yield stress has been accepted as a conservative design limit. The allowable stress limits due to Condition III and IV loadings, described in subsection 4.2.1.5.3, are also applied to the fuel rod.

Clad Strain

[*The total plastic tensile creep strain due to uniform clad creep, and uniform cylindrical fuel pellet expansion associated with fuel swelling and thermal expansion is less than one percent from the unirradiated condition, WCAP-12488-A (Reference 1).*]* The acceptance limit for fuel rod clad strain during Condition II events is that the total tensile strain due to uniform cylindrical pellet thermal expansion is less than one percent from the pre-transient value. These limits are consistent with proven practice.

4.2.1.1.3 Fatigue and Vibration

Fatigue

[*The usage factor due to cycle fatigue is less than 1.0, WCAP-12488-A (Reference 1).*]* That is, for a given strain range, the number of strain fatigue cycles are less than those required for failure. The fatigue curve is based on a safety factor of two on the stress amplitude or a safety factor of 20 on the number of cycles, whichever is more conservative.

Vibration

Potential fretting wear due to vibration is prevented, giving confidence that the stress-strain limits are not exceeded during design life. Fretting of the clad surface can occur due to flow-induced vibration between the fuel rods and fuel assembly grid springs. Vibration and fretting forces may vary during the fuel life due to clad diameter creep down combined with grid spring relaxation.

4.2.1.1.4 Chemical Properties

Chemical properties of the ZIRLO™ cladding are discussed in WCAP-12610 (Reference 5).

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

4.2.1.2 Fuel Material

4.2.1.2.1 Thermal-Physical Properties

The center temperature of the hottest pellet is below the melting temperature of the uranium dioxide. The melting temperature of unirradiated uranium dioxide, 5080°F, decreases by 58°F per 10,000 megawatt days per metric ton of uranium, as discussed in WCAP-9179 (Reference 4). Fuel melting will not occur at the overpower limit for Condition I or II events. This provides sufficient margin for uncertainties as described in subsection 4.4.2.9.

The nominal design density of the fuel is approximately 95 percent of the theoretical density. Additional information on fuel properties is provided in WCAP-9179 (Reference 4).

4.2.1.2.2 Fuel Densification and Fission Product Swelling

The design bases and models used for fuel densification and swelling are provided in WCAP-8218-P-A (Reference 6), WCAP-10851-P-A (Reference 7), and WCAP-13589-A (Reference 8).

4.2.1.2.3 Chemical Properties

WCAP-9179 (Reference 4) and WCAP-12610 (Reference 5) provide the basis for justifying that no adverse chemical interactions occur between the fuel and its adjacent material.

4.2.1.3 Fuel Rod Performance

4.2.1.3.1 Fuel Rod Models

The basic fuel rod models and the ability to predict fuel rod operating characteristics are given in WCAP-15063-P-A, Revision 1 (Reference 21) and subsection 4.2.3.

4.2.1.3.2 Mechanical Design Limits

Cladding collapse is precluded during the fuel rod design lifetime. Current generation Westinghouse fuel is sufficiently stable with respect to fuel densification. Significant axial gaps in the pellet stack necessary for clad flattening do not occur and therefore, clad flattening will not occur. Clad flattening methodologies are described in WCAP-13589-A, (Reference 8) and WCAP-8377 (Reference 22).

The rod internal gas pressure remains below the value which causes the fuel/clad diametral gap to increase due to outward cladding creep during steady-state operation. Rod pressure is also limited such that extensive departure from nucleate boiling propagation does not occur as discussed in WCAP-8963-P-A (Reference 9).

4.2.1.4 Spacer Grids

4.2.1.4.1 Mechanical Limits and Materials Properties

The grid component strength criteria are based on experimental tests. The limit is established at the 95-percent confidence level on the true mean crush strength at operating temperature. This limit is sufficient to provide that, under worst-case combined seismic and pipe rupture event, the core will maintain a geometry amenable to cooling. As an integral part of the fuel assembly structure, the grids satisfy the applicable fuel assembly design bases and limits defined in subsection 4.2.1.5.

The grid material and chemical properties are given in WCAP-9179 (Reference 4).

4.2.1.4.2 Vibration and Fatigue

The grids provide sufficient fuel rod support to limit fuel rod vibration and maintain clad fretting wear within acceptable limits (defined in subsection 4.2.1.1).

4.2.1.5 Fuel Assembly Structural Design

As discussed in subsection 4.2.1, the structural integrity of the fuel assemblies is provided by setting design limits on stresses and deformations due to various non-operational, operational, and accident loads. These limits are applied to the design and evaluation of the top and bottom nozzles, guide thimbles, grids, and thimble joints. [*Design changes to the fuel assembly structure qualify for evaluation in WCAP-12488-A (Reference 1).*]*

The design bases for evaluating the structural integrity of the fuel assemblies are discussed in subsections 4.2.1.5.1 through 4.2.1.5.3.

4.2.1.5.1 Non-Operational

The non-operational load is a loading of 4 g axial (longitudinal) and 6 g lateral (transverse) with dimensional stability.

4.2.1.5.2 Normal Operation and Operational Transients (Condition I) and Events of Moderate Frequency (Condition II)

For the normal operation (Condition I) and upset (Condition II) conditions, the fuel assembly component structural design criteria are established for the two primary material categories, austenitic steels and zirconium alloys. The stress categories and strength theory presented in the ASME Code, Section III, are used as a general guide. The maximum shear theory (Tresca criterion) for combined stresses is used to determine the stress intensities for the austenitic steel components. The stress intensity is defined as the largest numerical difference between the various principal stresses in a three-dimensional field. The design stress intensity value, S_m, for austenitic steels and zirconium alloys is given by the lowest of the following:

- One-third of the specified minimum tensile strength or two-thirds of the specified minimum yield strength at room temperature

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- One-third of the tensile strength or 90 percent of the yield strength at room temperature, but not to exceed two-thirds of the specified minimum yield strength at room temperature

The stress limits for the austenitic steel components are given below. Stress nomenclature follows the ASME Code, Section III.

Stress Intensity Limits

Categories	**Limit**
General primary membrane stress intensity	S_m
Local primary membrane stress intensity	1.5 S_m
Primary membrane plus bending stress intensity	1.5 S_m
Total primary plus secondary stress intensity	3.0 S_m

The zirconium alloy structural components, which consist of guide thimbles and fuel tubes, are in turn subdivided into two categories because of material difference and functional requirements. The fuel tube design criteria are covered separately in subsection 4.2.1.1. The maximum shear theory is used to evaluate the guide thimble design. For conservative purposes, the zirconium alloy unirradiated properties are used to define the stress limits.

4.2.1.5.3 Infrequent Incidents (Condition III) and Limiting Faults (Condition IV)

Typical worse case abnormal loads during Conditions III and IV are represented by seismic and pipe rupture loadings. The design criteria for this category of loadings are as follows:

- Deflections or excessive deformation of components cannot interfere with capability of insertion of the control rods or emergency cooling of the fuel rods.

- The fuel assembly structural components stresses under faulted conditions are evaluated primarily using the methods outlined in Appendix F of the ASME Code, Section III. Since the current analytical methods use linear elastic analysis, the stress allowables are defined as the smaller value of 2.4 S_m or 0.70 S_u for primary membrane and 3.6 S_m or 1.05 S_u for primary membrane plus primary bending. For the austenitic steel fuel assembly components, the stress intensity is defined in accordance with the rules described in the previous section for normal operating conditions. For the zirconium alloy components, the stress intensity limits are set at two-thirds of the material yield strength, S_y, at reactor operating temperature. This results in zirconium alloy stress limits being the smaller value of 1.6 S_y or 0.70 S_u for

primary membrane and 2.4 S_y or 1.05 S_u for primary membrane plus bending. For conservative purposes, the zirconium alloy unirradiated properties are used to define the stress limits.

The material and chemical properties of the fuel assembly components are given in WCAP-9179 (Reference 4). Subsection 4.2.3.4 discusses the spacer grid crush testing.

Thermal-hydraulic design is discussed in Section 4.4.

4.2.1.6 In-core Control Components

The in-core control components are subdivided into permanent and temporary devices. The permanent components are the rod cluster control assemblies, gray rod cluster assemblies, and secondary neutron source assemblies. The temporary components are the primary neutron source assemblies (which are normally used only in the initial core) and the burnable absorber assemblies. For some reloads, the use of burnable absorbers may be necessary for power distribution control and/or to achieve an acceptable moderator temperature coefficient throughout core life (See Subsection 4.3.1.2.2). [*Design changes to the in-core control components qualify for evaluation using the criteria defined in WCAP-12488-A (Reference 1).*]*

Materials are selected for:

- Compatibility in a pressurized water reactor environment
- Adequate mechanical properties at room and operating temperatures
- Resistance to adverse property changes in a radioactive environment
- Compatibility with interfacing components

Material properties are given in WCAP-9179 (Reference 4).

The design bases for the in-core control components are given in subsections 4.2.1.6.1 through 4.2.1.6.3.

4.2.1.6.1 Control Rods

For Conditions I and II, the stress categories and strength theory presented in the ASME Code, Section III, are used as a general guide in the design of the control rod assembly structural parts in addition to absorber cladding.

Design conditions considered under the ASME Code, Section III, are as follows:

- External pressure equal to the reactor coolant system operating pressure with appropriate allowance for overpressure transients

- Wear allowance equivalent to 1000 reactor trips

- Bending of the rod due to a misalignment in the guide thimble

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- Forces imposed on the rods during rod drop
- Loads imposed by the accelerations of the control rod drive mechanism
- Radiation exposure during maximum core life. The absorber material temperature does not exceed its melting temperature (1454°F for silver-indium-cadmium [Ag-In-Cd]), (see WCAP-9179, Reference 4).
- Temperature effects at operating conditions

4.2.1.6.2 Burnable Absorber Rods

For Conditions I and II, the stress categories and strength theory presented in the ASME Code, Section III, are used as a general guide in the design of the burnable absorber cladding. For abnormal loads during Conditions III and IV, code stresses are not considered limiting. Failures of the burnable absorber rods during these conditions must not interfere with reactor shutdown or emergency cooling of the fuel rods. The burnable absorber material is nonstructural. The structural elements of the burnable absorber rod are designed to maintain the absorber geometry even if the absorber material is fractured.

The discrete burnable absorber material is boron carbide contained in an alumina matrix. Thermal-physical and gas release properties of alumina-boron carbide are described in WCAP-9179 (Reference 4) and WCAP-10021-P-A (Reference 10). Discrete burnable absorber rods are designed so that the absorber temperature does not exceed 1200°F during normal operation or an overpower transient. The 1200°F maximum temperature helium gas release in a discrete burnable absorber rod will not exceed 30 percent of theoretical. See WCAP-10021-P-A (Reference 10).

4.2.1.6.3 Neutron Source Rods

The neutron source rods are designed to withstand the following:

- The external pressure equal to reactor coolant system operating pressure with appropriate allowance for overpressure transients
- An internal pressure equal to the pressure generated by released gases over the source rod life

4.2.1.7 Surveillance Program

Subsection 4.2.4.6 discusses the testing and fuel surveillance operation experience program that has been and is being conducted to verify the adequacy of the fuel performance and design bases. Fuel surveillance and testing results, as they become available, are used to improve fuel rod design and manufacturing processes and to confirm that the design bases and safety criteria are satisfied.

4.2.2 Description and Design Drawings

The fuel assembly, fuel rod, and in-core control component design data is given in Table 4.3-1.

Each fuel assembly consists of 264 fuel rods, 24 guide thimbles, and 1 instrumentation tube arranged within a supporting structure. The instrumentation thimble is located in the center position and provides a channel for insertion of an in-core neutron detector, if the fuel assembly is located in an instrumented core position. The guide thimbles provide channels for insertion of either a rod cluster control assembly, a gray rod cluster assembly, a neutron source assembly, or burnable absorber assembly, depending on the position of the particular fuel assembly in the core. Figure 4.2-1 shows a cross-section of the fuel assembly array, and Figure 4.2-2 shows a fuel assembly full-length view.

The fuel rods are loaded into the fuel assembly structure so that there is clearance between the fuel rod ends and the top and bottom nozzles. The fuel rods are supported within the fuel assembly structure by fourteen structural grids (top grid (1), bottom grid (1), intermediate grids (8) and intermediate flow mixer (IFM) grids (4)), plus one protective grid. The top grid is fabricated from nickel-chromium-iron Alloy 718 or ZIRLO™. The bottom grid is fabricated from nickel-chromium-iron Alloy 718. The intermediate grids and the IFM grids are fabricated from ZIRLO™ (see WCAP-12610-P-A, Reference 5). Top, bottom, and intermediate grids provide axial and lateral support to the fuel rods. In addition, the four IFM grids located near the center of the fuel assembly and between the intermediate grids provide additional fuel rod restraint. The protective grid, in combination with the debris filter bottom nozzle (DFBN) and the long, solid fuel rod bottom end plug, provides debris failure mitigation.

Fuel assemblies are installed vertically in the reactor vessel and stand upright on the lower core plate, which is fitted with alignment pins to locate and orient each assembly. After the fuel assemblies are set in place, the upper support structure is installed. Alignment pins, built into the upper core plate, engage and locate the upper ends of the fuel assemblies. The upper core plate then bears down against the hold-down springs on the top nozzle of each fuel assembly to hold the fuel assemblies in place.

Improper orientation of fuel assemblies within the core is prevented by the use of an indexing hole in one corner of the top nozzle top plate. The assembly is oriented with respect to the handling tool and the core by means of a pin inserted into this indexing hole. Visual confirmation of proper orientation is also provided by an engraved identification number on the opposite corner clamp.

4.2.2.1 Fuel Rods

The fuel rods consist of uranium dioxide ceramic pellets contained in cold-worked and stress relieved ZIRLO™ tubing, which is plugged and seal-welded at the ends to encapsulate the fuel. ZIRLO™ is an advanced zirconium based alloy selected for its mechanical properties and low neutron absorption cross-section (see WCAP-12610-P-A, Reference 5). Figure 4.2-3 shows a schematic of the fuel rod. The fuel pellets are right circular cylinders consisting of slightly enriched uranium dioxide powder which has been compacted by cold pressing and then sintered to the required density. The ends of each pellet are dished slightly, to allow greater axial expansion at the pellet centerline and to increase the void volume for fission gas release. The ends of each pellet also have a small chamfer at the outer cylindrical surface which improves manufacturability, and mitigates potential pellet damage due to fuel rod handling.

Void volume and clearances are provided within the rods to accommodate fission gases released from the fuel, differential thermal expansion between the clad and the fuel, and fuel density changes during irradiation. To facilitate the extended burnup capability necessitated by longer operating cycles, the fuel rod is designed with two plenums (upper and lower) to accommodate the additional fission gas release. The upper plenum volume is maintained by a fuel pellet hold-down spring. The lower plenum volume is maintained by a standoff assembly.

Shifting of the fuel within the clad during handling or shipping, prior to core loading, is prevented by a stainless steel helical spring which bears on top of the fuel pellet stack. Assembly consists of plugging and welding the bottom of the cladding, installing the bottom plenum spacer assembly, fuel pellets and top plenum spring, and then plugging and welding the top of the rod. The solid bottom end plug has an internal grip feature and tapered end to facilitate fuel rod loading during fuel assembly fabrication and reconstitution. Additionally, the bottom end plug is designed to be sufficiently long to extend through the bottom grid. This precludes any breach in the fuel rod pressure boundary due to clad fretting wear induced by debris trapped at the bottom grid location.

The fuel rods are internally pressurized with helium during the welding process to minimize compressive clad stresses and prevent clad flattening under reactor coolant operating pressures. The fuel rods are pre-pressurized and designed so that:

- The internal gas pressure mechanical design limit referred to in subsection 4.2.1.3 is not exceeded

- The cladding stress-strain limits (subsection 4.2.1.1) are not exceeded for Condition I and II events

- Clad flattening will not occur during the fuel core life

The AP1000 fuel rod design may also include axial blankets. The axial blankets consist of fuel pellets of a reduced enrichment at each end of the fuel rod pellet stack. Axial blankets reduce neutron leakage axially and improve fuel utilization. The axial blankets use chamfered pellets that are longer than the enriched pellets to help prevent accidental mixing during manufacturing. Furthermore, axial blankets have no impact on the source range detector response, since the reduction in power from the axial blanket is limited to the top and bottom 0.67 feet of the core, while the source range detectors are centered typically about three feet from the bottom of the core.

The AP1000 fuel rod design may also include annular fuel pellets in the top and bottom 8 inches of the fuel stack. These pellets can be either fully enriched or partially enriched. The annular fuel pellets provide additional void volume in the fuel rod to accommodate fission gas release.

The AP1000 fuel rods include integral fuel burnable absorbers. The integral fuel burnable absorbers may be boride-coated fuel pellets or fuel pellets containing gadolinium oxide mixed with uranium oxide. The boride-coated fuel pellets are identical to the enriched uranium dioxide pellets except for the addition of a thin boride coating less than 0.001 inch in thickness on the pellet cylindrical surface. Coated pellets occupy the central portion of the fuel column. The number and pattern of integral fuel burnable absorber rods within an assembly may vary

depending on specific application. An evaluation and test program for the integral fuel burnable absorber design features for the boride-coated fuel pellets is summarized in Section 2.5 of WCAP-8183 (Reference 3).

4.2.2.2 Fuel Assembly Structure

As shown in Figure 4.2-2, the fuel assembly structure consists of a bottom nozzle, top nozzle, fuel rods, guide thimbles, and grids.

4.2.2.2.1 Bottom Nozzle

The bottom nozzle serves as the bottom structural element of the fuel assembly and directs the coolant flow distribution to the assembly. The nozzle is fabricated from Type 304 stainless steel and consists of a perforated plate, and casting which incorporates a skirt and four angle legs with bearing pads. Figure 4.2-2 illustrates this concept. The legs and skirt form a plenum to direct the inlet coolant flow to the fuel assembly. The perforated plate also prevents accidental downward ejection of the fuel rods from the fuel assembly. The bottom nozzle is fastened to the fuel assembly guide thimbles by locked thimble screws, which penetrate through the nozzle and engage with a threaded plug in each guide thimble.

Coolant flows from the plenum in the bottom nozzle, upward through the penetrations in the plate, to the channels between the fuel rods. The penetrations in the plate are positioned between the rows of the fuel rods.

In addition to serving as the bottom structural element of the fuel assembly, the bottom nozzle also functions as a debris filter. The bottom nozzle perforated plate contains a multiplicity of flow holes which are sized to minimize passage of detrimental debris particles into the active fuel region of the core while maintaining sufficient hydraulic and structural margins. Furthermore, the skirt provides improved bottom nozzle structural stability and increased design margins to reduce damage due to abnormal handling.

Axial loads (from top nozzle hold-down springs) imposed on the fuel assembly and the weight of the fuel assembly are transmitted through the bottom nozzle to the lower core plate. Indexing and positioning of the fuel assembly is controlled by alignment holes in two diagonally opposite bearing pads that mate with locating pins in the lower core plate. Lateral loads on the fuel assembly are transmitted to the lower core plate through the locating pins.

The AP1000 bottom nozzle also has a reconstitution design feature which facilitates the easy removal of the nozzle from the fuel assembly. This design incorporates a thimble screw with a circular locking cup located around the screw head. The locking cup is crimped into a local spherical radius relief on the bottom nozzle. To remove the bottom nozzle, a counterclockwise torque is applied to the thimble screw until the locking cup (detents) is relaxed and the thimble screw is removed. This reconstitutable design permits the remote unlocking, the removal, and the relocking of the thimble screws, as the same or a new bottom nozzle is reattached to the fuel assembly.

4.2.2.2.2 Top Nozzle

The reconstitutable top nozzle functions as the upper structural component of the fuel assembly and, in addition, provides a partial protective housing for the rod cluster control assembly, discrete burnable absorber, or other core components. The basic components of the welded top nozzle include the adapter plate, enclosure, and top plate. As shown in Figure 4.2-2, the top nozzle assembly includes four sets of hold-down springs and associated spring screws and clamps, which are secured to the top nozzle top plate. The springs are made of nickel-chromium-iron Alloy 718. The spring screws are made of nickel-chromium-iron Alloy 718. The other top nozzle components are made of Type 304 stainless steel.

The adapter plate is provided with round penetrations and slots (with semicircular ends) to permit the flow of coolant upward through the top nozzle. Other round holes are provided in the adapter plate to accept (guide thimble) inserts which are mechanically locked to the adapter plate using a lock tube. The unique design of the insert joint and lock tube are the key design features of the reconstitutable top nozzle.

The ligaments in the adapter plate cover the top of the fuel rods precluding any upward ejection of the fuel rods from the fuel assembly. The enclosure is a box-like structure which establishes the distance between the adapter plate and the top plate. The top plate has a large square hole in the center to permit access for the rod cluster control assembly, burnable absorber assembly, or other components. Hold-down springs are mounted on the top plate and are retained by spring screws located at diagonally opposite corners of the top plate.

The top plate also contains integral pads located on the two remaining top nozzle corners. The pads include alignment holes which, when fully engaged with the reactor internals upper core plate guide pins, provide proper alignment to the fuel assembly, reactor internals, and rod control cluster assembly.

As shown in Figure 4.2-4, to remove the top nozzle assembly a tool is first inserted through a lock tube and expanded radially to engage the bottom edge of the tube. An axial force is then exerted on the tool which overrides local lock tube deformations and withdraws the lock tubes from the inserts. After the lock tubes have been removed, the nozzle assembly is removed by raising it off the upper slotted ends of the nozzle inserts, which deflect inwardly under the axial lift load.

With the top nozzle assembly removed, direct access is provided for fuel rod examination or replacement. Reconstitution is completed by the remounting of the nozzle assembly and the insertion of lock tubes. Details of this design feature, the design bases and evaluation of the reconstitutable top nozzle are given in WCAP-10444-P-A (Reference 11).

4.2.2.2.3 Guide Thimbles and Instrument Tube

The guide thimbles are structural members that provide channels for the neutron absorber rods, burnable absorber rods, neutron source rods, or other assemblies. Each guide thimble is fabricated from Zircaloy-4 or ZIRLO™ with constant OD and ID over the entire length. Separate dashpot tubes, which are made from Zircaloy-4 or ZIRLO™ tubing, are inserted into the bottom portion of the guide thimble tubes. The larger tube diameter at the top section provides a relatively large

annular area necessary to permit rapid control rod insertion during a reactor trip, as well as to accommodate the flow of coolant during normal operation. Holes are provided on the guide thimble above the dashpot to reduce the rod drop time. The lower portion of the guide thimble with the dashpot tube results in a dashpot action near the end of the control rod travel during normal trip operation. The dashpot is closed at the bottom by means of an end plug, which is provided with a small flow port to avoid fluid stagnation in the dashpot volume during normal operation.

As stated previously, the AP1000 fuel assembly includes a reconstitutable top nozzle as a standard feature. To accommodate the reconstitutable feature, the top end of the zirconium alloy guide thimble is fastened to a tubular sleeve, or insert, by a three tier expansion bulge joint. An expansion tool is inserted inside the nozzle insert and guide thimble to the proper elevation. The four lobes on the expansion tool force the guide thimble and insert outward locally to a predetermined diameter, therefore joining the two components.

Upon installation of the top nozzle assembly, the bulge near the top of the nozzle insert is captured in a corresponding groove in the hole of the top nozzle adapter plate. As shown in Figure 4.2-4, the mechanical connection between the nozzle insert-guide thimble and top nozzle is made by insertion of a lock tube into the insert. The design of the top grid sleeve-guide thimble and top nozzle insert-guide thimble bulge joint connections have been mechanically tested and found to meet applicable design criteria.

The fuel rod support grids, with exception noted for the bottom nickel-chromium-iron Alloy 718 grid, are secured to the guide thimbles using a similar bulge joint connection to create an integral structure. Attachment of the intermediate mixing vane and intermediate flow mixer (IFM) zirconium alloy grids to the guide thimbles is performed using the fastening technique depicted in Figures 4.2-5 and 4.2-6.

The intermediate mixing vane and intermediate flow mixer grids employ a single tier bulge connection between the grid sleeve and guide thimble as compared to the three tier bulge connection used for the top grid. The design of the single tier bulge joint connection has also been mechanically tested and meets the design requirements.

The bottom nickel-chromium-iron Alloy 718 grid is secured to the guide thimble assembly by a double tier bulge connection between the grid sleeve and guide thimble. The design of the double tier bulge joint connection has also been mechanically tested and meets the design requirements.

The lower end of the guide thimble is fitted with a welded end plug. The nickel-chromium-iron Alloy 718 protective grid is secured to the guide thimble assembly by nickel-chromium-iron Alloy 718 spacers that are spot-welded to the grid. As shown in Figure 4.2-7, the spacer is captured between the guide thimble end plug and the bottom nozzle by means of a (thimble) locking screw.

The described methods of grid fastening are standard and have been used successfully since the introduction of zirconium alloy guide thimbles in 1969.

The central instrumentation tube in each fuel assembly is constrained by seating in counterbores located in both top and bottom nozzles. The instrumentation tube has a constant diameter and

provides an unrestricted passageway for the in-core neutron detector which enters the fuel assembly from the top nozzle. Furthermore, the instrumentation tube is secured to the top and mid-grids with bulge joint connections similar to those previously discussed for securing the grids to the guide thimbles.

4.2.2.2.4 Grid Assemblies

As shown in Figure 4.2-2, the fuel rods are supported at intervals along their lengths by grid assemblies which maintain the lateral spacing between the rods throughout the design life of the assembly. Each fuel rod is given support at six contact points within each grid by the combination of support dimples and springs. The grid assembly consists of individual slotted straps assembled and interlocked into an egg-crate type arrangement with the straps permanently joined at their points of intersection. The straps may contain springs, support dimples, and mixing vanes; or any such combination.

Two types of structural grid assemblies are used on the AP1000 fuel assembly. One type, with mixing vanes projecting from the edges of the straps into the coolant stream, is used in the high heat flux region of the fuel assemblies to promote mixing of the coolant. The other type, located at the top and bottom of the assembly, does not contain mixing vanes on the internal straps. The outside straps on the grids contain mixing vanes that, in addition to their mixing function, aid in guiding the grids and fuel assemblies past projecting surfaces during handling or during loading and unloading of the core.

Because of its corrosion resistance and high strength properties, the bottom grid material chosen for the AP1000 fuel assembly design is nickel-chromium-iron Alloy 718. The top grid may be fabricated from nickel-chromium-iron Alloy 718, or ZIRLO™. The magnitude of the grid restraining force on the fuel rod is set high enough to minimize possible fretting, without overstressing the cladding at the points of contact between the grids and fuel rods. The grid assemblies are designed to allow axial thermal expansion of the fuel rods without imposing restraint sufficient to develop buckling or distortion of the fuel rods.

The eight intermediate (mixing vane), or structural grids on the AP1000 fuel assembly are made of ZIRLO™. This material was selected to take advantage of the material’s inherent low neutron capture cross-section. The zirconium alloy grids have thicker straps than the nickel-chromium-iron alloy grids. The zirconium alloy grid incorporates the same grid cell support configuration as the nickel-chromium-iron alloy grid. The zirconium alloy interlocking strap joints and grid/sleeve joints are fabricated by laser welding, whereas the nickel-chromium-iron alloy grid joints are brazed. The mixing vanes incorporated in the zirconium alloy intermediate grids induce additional flow mixing among the various flow channels in a fuel assembly as well as between adjacent fuel assemblies. This additional flow mixing enhances thermal performance.

As shown in Figure 4.2-2, the intermediate flow mixer grids are located at selected spans between the zirconium alloy mixing vane structural grids and incorporate a similar mixing vane array. Their prime function is mid-span flow mixing in the hotter fuel assembly spans. Each intermediate flow mixer grid cell contains four dimples that are designed to prevent mid-span channel closure in the spans containing intermediate flow mixers and fuel rod contact with the mixing vanes. This

simplified cell arrangement allows short grid cells so that the intermediate flow mixer grid can accomplish its flow mixing objective with minimal pressure drop.

The intermediate flow mixer (IFM) grids, like the mixing vane grids, are fabricated from ZIRLO™. The intermediate flow mixer grids are manufactured using the same basic techniques as the zirconium alloy structural grid assemblies and are joined to the guide thimbles via sleeves which are welded at the bottom of appropriate grid cells.

Grid impact testing has been performed on zirconium alloy structural grids and the intermediate flow mixer grids indicative of the AP1000 design. The purpose of the testing was to determine the dynamic buckling, or crush, strength of the grids. The grid impact testing was performed at an elevated temperature of 600°F. This temperature is a conservative value representing the core average temperature at the mid-grid locations.

The intermediate flow mixer grids are not intended to be structural members. The intermediate flow mixer grids do, however, share the loads of the structural grids during faulted loading and, as such, contribute to enhance the load carrying capability of the AP1000 fuel assembly.

The dynamic crush strength of the AP1000 structural grids and intermediate flow mixer grids envelope the calculated grid impact loading during combined seismic and pipe rupture events. A coolable geometry is, therefore, provided at the intermediate flow mixer grid elevations, as well as at the structural grid elevations.

4.2.2.3 In-core Control Components

Reactivity control is provided by neutron absorbing rods, gray rods, burnable absorber rods, and a soluble chemical neutron absorber (boric acid). The boric acid concentration is varied to control long-term reactivity changes such as:

- Fuel depletion and fission product buildup
- Cold to hot, zero power reactivity changes
- Reactivity change produced by intermediate-term fission products such as xenon and samarium
- Burnable absorber depletion

The chemical and volume control system, which is used to adjust the level of boron in the coolant, is discussed in Section 9.3.

The rod cluster control assemblies provide reactivity control for:

- Shutdown
- Reactivity changes due to coolant temperature changes in the power range
- Reactivity changes associated with the power coefficient of reactivity
- Reactivity changes due to void formation

A negative power coefficient is maintained at hot, full-power conditions throughout the entire cycle to reduce possible deleterious effects caused by a positive coefficient during pipe rupture or loss-of-flow accidents. The first fuel cycle needs more excess reactivity than subsequent cycles due to the loading of fresh (unburned) fuel. Since soluble boron alone is insufficient to provide a negative moderator coefficient, burnable absorber assemblies are also used. Use of burnable absorber assemblies during reloads is discussed in subsection 4.3.1.2.2.

The most effective reactivity control components are the rod cluster control assemblies and the corresponding drive rod assemblies, which along with the gray rod cluster assemblies, are the only kinetic parts in the reactor. Figure 4.2-8 identifies the rod cluster control and drive rod assembly, in addition to the arrangement of these components in the reactor relative to the interfacing fuel assembly, guide thimbles, and control rod drive mechanism. The arrangement for the gray rod cluster assemblies is the same.

As shown in Figure 4.2-8, the guidance system for the rod cluster control assembly is provided by the guide thimbles. The guide thimbles provide two regimes of guidance: first, in the lower section, a continuous guidance system provides support immediately above the core, which protects the rod against excessive deformation and wear caused by hydraulic loading. Second, the region above the continuous section provides support and guidance at uniformly spaced intervals.

As shown in Figure 4.2-9, the envelope of support is determined by the pattern of the control rod cluster. The guide thimbles provide alignment and support of the control rods, spider body, and drive rod while maintaining trip times at or below required limits.

Subsections 4.2.2.3.1 through 4.2.2.3.4 describe each reactivity control component in detail. The control rod drive mechanism assembly is described in subsection 3.9.4. The neutron source assemblies provide a means of monitoring the core during periods of low neutron activity.

4.2.2.3.1 Rod Cluster Control Assemblies

The rod cluster control assemblies are divided into two categories: control and shutdown. The control groups compensate for reactivity changes due to variations in operating conditions of the reactor, that is, power and temperature variations. Two nuclear design criteria have been employed for selection of the control group. First, the total reactivity worth must be adequate to meet the nuclear requirements of the reactor. Second, in view of the fact that these rods may be partially inserted at power operation, the total power peaking factor should be low enough to confirm that the power capability is met. The control and shutdown groups provide adequate shutdown margin.

As illustrated in Figure 4.2-9, a rod cluster control assembly is comprised of a group of individual neutron absorber rods fastened at the top end to a common spider assembly.

The absorber material used in the control rods is silver-indium-cadmium alloy, which is essentially “black” to thermal neutrons and has sufficient additional resonance absorption to significantly increase worth. As shown in Figure 4.2-10, the absorber material is in the form of solid bars sealed in cold-worked stainless steel tubes. Sufficient diametral and end clearance is provided to accommodate relative thermal expansions.

The control rods have bottom plugs with bullet-like tips to reduce the hydraulic drag during reactor trip and to guide smoothly into the dashpot section of the fuel assembly guide thimbles.

The material used in the absorber rod end plugs is Type 308 stainless steel. The design stresses used for the Type 308 material are the same as those defined in the ASME Code, Section III, for Type 304 stainless steel. At room temperature, the yield and ultimate stresses per ASTM 580 (Reference 12) are exactly the same for the two alloys. In view of the similarity of composition of the alloys, the temperature dependence of strength for the two materials is expected to be the same.

The allowable stresses used as a function of temperature are listed in Table I-1.2 of the ASME Code, Section III. The fatigue strength for the Type 308 material is based on the S-N curve for austenitic stainless steels in Figure I-9.2 of the ASME Code, Section III.

The spider assembly is in the form of a central hub with radial vanes containing cylindrical fingers from which the absorber rods are suspended. Internal groove-like profiles to facilitate handling tool and drive rod assembly connection are machined into the upper end of the hub. Coil springs inside the spider body absorb the impact energy at the end of a trip insertion. The radial vanes are joined to the hub by welding and brazing, and the fingers are joined to the vanes by brazing. A bolt, which holds the springs and retainer, is threaded into the hub within the skirt and welded to prevent loosening while in service.

The components of the spider assembly are made from Types 304 and 308 stainless steel except for the retainer, which is of 17-4 PH material, and the springs, which are nickel-chromium-iron Alloy 718.

The absorber rods are fastened securely to the spider. The rods are first threaded into the spider fingers and then pinned to maintain joint tightness. The pins are then welded in place. The end plug below the pin position is designed with a reduced section to permit flexing of the rods to correct for small operating or assembly misalignments.

The overall length of the rod cluster control assembly is such that, when the assembly is withdrawn through its full travel, the tips of the absorber rods remain engaged in the guide thimbles so that alignment between rods and thimbles is always maintained. Since the rods are long and slender, they are relatively free to conform to any small misalignments with the guide thimble.

4.2.2.3.2 Gray Rod Cluster Assemblies

The mechanical design of the gray rod cluster assemblies plus the control rod drive mechanism and the interface with the fuel assemblies and guide thimbles are identical to the rod cluster control assembly.

As shown in Figure 4.2-11, the gray rod cluster assemblies consist of 24 rodlets fastened at the top end to a common hub or spider. Geometrically, the gray rod cluster assembly is the same as a rod cluster control assembly except that 20 of the 24 rodlets are stainless steel while the remaining four contain the same silver-indium-cadmium absorber material clad with stainless steel as the rod cluster control assemblies.

The gray rod cluster assemblies are used in load follow maneuvering and provide a mechanical shim to replace the use of changes in the concentration of soluble boron, that is, a chemical shim, normally used for this purpose. The AP1000 uses 53 rod cluster control assemblies and 16 gray rod cluster assemblies.

4.2.2.3.3 Burnable Absorber Assembly

Each burnable absorber assembly consists of discrete burnable absorber rods attached to a hold-down assembly. Figure 4.2-12 shows the burnable absorber assemblies. When needed for nuclear considerations, burnable absorber assemblies are inserted into selected thimbles within fuel assemblies.

The typical discrete burnable absorber rods consist of pellets of alumina-boron carbide material contained within zirconium alloy tubes. These zirconium alloy tubes, which form the outer clad for the burnable absorber rod, are plugged, pressurized with helium, and seal-welded at each end to encapsulate the stack of absorber material. The absorber stack length, shown in Figure 4.2-12, is positioned axially within the burnable absorber rod by the use of a zirconium alloy bottom-end spacer.

The burnable absorber rods in each fuel assembly are grouped and attached together at the top end of the rods to a hold-down assembly by a flat, perforated retaining plate, which fits within the fuel assembly top nozzle and rests on the adapter plate.

The retaining plate and the burnable absorber rods are held down and restrained against vertical motion through a spring pack which is attached to the plate and is compressed by the upper core plate when the reactor upper internals assembly is lowered into the reactor. With this arrangement, the burnable absorber rods cannot be ejected from the core by flow forces. Each rod is attached to the baseplate by a nut that is crimped into place.

4.2.2.3.4 Neutron Source Assemblies

The purpose of a neutron source assembly is to provide a base neutron level to give confidence that the detectors are operational and responding to core multiplication neutrons. For the first core, a neutron source is placed in the reactor to provide a positive neutron count of at least two counts per second on the source range detectors attributable to core neutrons. The detectors, called source range detectors, are used primarily during subcritical modes of core operation.

The source assembly also permits detection of changes in the core multiplication factor during core loading, refueling, and approach to criticality. This can be done since the multiplication factor is related to an inverse function of the detector count rate. Changes in the multiplication factor can be detected during addition of fuel assemblies while loading the core, changes in control rod positions, and changes in boron concentration.

Both primary and secondary neutron source rods are used. The primary source rod, containing a radioactive material, spontaneously emits neutrons during initial core loading, reactor startup, and initial operation of the first core. After the primary source rod decays beyond the desired neutron

flux level, neutrons are then supplied by the secondary source rod. The secondary source rod contains a stable material, which is activated during reactor operation. The activation results in the subsequent release of neutrons.

Four source assemblies are typically installed in initial load of the reactor core: two primary source assemblies and two secondary source assemblies. Each primary source assembly contains one primary source rod and a number of burnable absorber rods. Each secondary source assembly contains a symmetrical grouping of secondary source rodlets. Figure 4.2-14 shows the primary source assembly. Figure 4.2-15 shows the secondary source assembly.

Neutron source assemblies are employed at opposite sides of the core. The source assemblies are inserted into the rod cluster control guide thimbles in fuel assemblies at selected locations.

As shown in Figures 4.2-14 and 4.2-15, the source assemblies contain a hold-down assembly identical to that of the burnable absorber assembly.

The primary and secondary source rods both use the same cladding material as the absorber rods. The secondary source rods contain antimony-beryllium pellets stacked to a height of approximately 88 inches. The primary source rods contain capsules of californium (plutonium-beryllium possible alternate) source material and alumina spacers to position the source material within the cladding. The rods in each assembly are fastened at the top end to a hold-down assembly.

The other structural members, except for the springs, are constructed of Type 304 stainless steel. The springs exposed to the reactor coolant are nickel-chromium-iron Alloy 718.

4.2.3 Design Evaluation

[*The fuel assemblies, fuel rods, and in-core control components are designed to satisfy the performance and safety criteria of*]* Section 4.2 of the Standard Review Plan, the mechanical design bases of subsection 4.2.1 and [*the Fuel Criteria Evaluation Process per WCAP-12488-A (Reference 1)*]*, and other interfacing nuclear and thermal and hydraulic design bases specified in Sections 4.3 and 4.4.

Effects of Conditions II, III, IV or anticipated transients without trip on fuel integrity are presented in Chapter 15.

The initial step in fuel rod design evaluation for a region of fuel is to determine the limiting rod(s). Limiting rods are defined as those rods whose predicted performance provides the minimum margin to each of the design criteria. For a number of design criteria, the limiting rod is the lead burnup rod of a fuel region. In other instances, it may be the maximum power or the minimum burnup rod. For the most part, no single rod is limiting with respect to all the design criteria.

After identifying the limiting rod(s), an analysis is performed to consider the effects of rod operating history, model uncertainties, and dimensional variations. To verify adherence to the design criteria, the evaluation considers the effects of postulated transient power changes during operation consistent with Conditions I and II. These transient power increases can affect both rod

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

average and local power levels. Parameters considered include rod internal pressure, fuel temperature, clad stress, and clad strain. In fuel rod design analyses, these performance parameters provide the basis for comparison between expected fuel rod behavior and the corresponding design criteria limits.

Fuel rod and assembly models used for the performance evaluations are documented and maintained under an appropriate control system. Material properties used in the design evaluations are given in WCAP-12610 (Reference 5).

4.2.3.1 Cladding

4.2.3.1.1 Vibration and Wear

Fuel rod vibrations are flow induced. The effect of vibration on the fuel assembly and individual fuel rods is minimal. The cyclic stress range associated with deflections of such small magnitude is insignificant and has no effect on the structural integrity of the fuel rod.

The reaction force on the grid supports, due to rod vibration motions, is also small and is much less than the spring preload. Adequate fuel clad spring contact is maintained. No significant wear of the clad or grid supports is predicted during the life of the fuel assembly based on out-of-pile flow tests, performance of similarly designed fuel in operating reactors, and design analyses.

Clad fretting and fuel vibration has been experimentally investigated, as shown in WCAP-8278 (Reference 13).

4.2.3.1.2 Fuel Rod Internal Pressure and Cladding Stresses

A burnup-dependent fission gas release model (WCAP-15063-P-A (Reference 21) and WCAP-10851-P-A (Reference 7)) is used in determining the internal gas pressure as a function of irradiation time. The plenum volume of the fuel rod has been designed to provide that the maximum internal pressure of the fuel rod will not exceed the value which would cause:

- The fuel/clad diametral gap to increase during steady-state operation
- Extensive departure from nucleate boiling propagation to occur

The clad stresses at a constant local fuel rod power are low. Compressive stresses are created by the pressure differential between the coolant pressure and the rod internal gas pressure. Because of the pre-pressurization with helium, the volume average effective stresses are always less than approximately 14,000 psi at the pressurization level used in the AP1000 fuel rod design. Stresses due to the temperature gradient are not included in this average effective stress because thermal stresses are, in general, negative at the clad inside diameter and positive at the clad outside diameter, and their contribution to the clad volume average stress is small. Furthermore, the thermal stress decreases with time during steady-state operation due to stress relaxation. The stress due to pressure differential is highest in the minimum power rod at beginning-of-life due to low internal gas pressure and decreases as rod power increases. Thermal stresses are maximum in the maximum power rod due to the larger temperature gradient and decrease as the rod power is decreased.

The internal gas pressure at beginning-of-life ranges from approximately 200 to 750 psi for typical lead burnup fuel rods. The total tangential stress at the clad inside diameter at beginning-of-life is approximately 19,500 psi compressive (approximately 18,500 psi due to ΔP and approximately 1,000 due to ΔT) for a low-power rod operating at four kilowatts/foot. Total tangential stress is approximately 20,500 psi compressive (approximately 18,000 psi due to ΔP and approximately 2,500 psi due to ΔT) for a high-power rod operating at 10 kilowatts/foot. However, the volume average effective stress at beginning-of-life is between approximately 13,500 psi (high-power rod) and approximately 14,000 psi (low-power rod). These stresses are substantially below even the unirradiated clad yield strength (approximately 55,500 psi) at a typical clad mean operating temperature of 700°F.

Tensile stresses could be created once the clad has come in contact with the pellet. These stresses would be induced by the fuel pellet swelling during irradiation. Swelling of the fuel pellet can result in small clad strains (less than one percent) for expected discharge burnups, but the associated clad stresses are very low because of clad creep (thermal- and irradiation-induced creep). The one percent strain criterion is extremely conservative for fuel-swelling driven clad strain because the strain rate associated with solid fission products swelling is very slow. A detailed discussion of fuel rod performance is given in subsection 4.2.3.3.

4.2.3.1.3 Material and Chemical Evaluation

ZIRLO™ clad has a high corrosion resistance to the coolant, fuel, and fission products. As shown in WCAP-8183 (Reference 3), there is considerable pressurized water reactor operating experience on the capability of Zircaloy-4 as a clad material. ZIRLO™, an advanced zirconium based alloy, has equal or better corrosion resistance than Zircaloy-4 (see WCAP-12610-P-A, Reference 5). Controls on fuel fabrication specify maximum moisture levels to preclude clad hydriding.

Metallographic examination of irradiated commercial fuel rods has shown occurrences of fuel/clad chemical interaction. Reaction layers of less than one mil in thickness have been observed between fuel and clad at limited points around the circumference. Metallographic data indicates that this interface layer remains very thin even at high burnup. Thus, there is no indication of propagation of the layer and eventual clad penetration.

Stress corrosion cracking is another postulated phenomenon related to fuel/clad chemical interaction. Out-of-pile tests have shown that in the presence of high clad tensile stresses, large concentrations of iodine can chemically attack the zirconium alloy tubing and may lead to eventual clad cracking. Extensive post-irradiation examination has produced no evidence that this mechanism has been operative in Westinghouse commercial pressurized water reactor fuel.

4.2.3.1.4 Rod Bowing

WCAP-8691 (Reference 14) presents the model used for evaluation of AP1000 fuel rod bowing. This model has been used for bow assessment in 14x14, 15x15, and 17x17 type cores.

4.2.3.1.5 Consequences of Power Coolant Mismatch

Consequences of power coolant mismatch are discussed in Chapter 15.

4.2.3.1.6 Creep Collapse and Creepdown

This subject and the associated irradiation stability of cladding have been evaluated. In WCAP-13589-A (Reference 8), it is shown that current generation Westinghouse fuel is sufficiently stable with respect to fuel densification. Significant axial gaps do not form in the pellet stack, preventing clad collapse from occurring. The design basis of no clad collapse during planned core life is therefore satisfied. Cladding collapse analyses, if required, would be performed using the methods described in WCAP-8377 (Reference 22).

4.2.3.2 Fuel Materials Considerations

Sintered, high-density uranium dioxide fuel reacts only slightly with the clad at core operating temperatures and pressures. In the event of clad defects, the high resistance of uranium dioxide to attack by water protects against fuel deterioration, although limited fuel erosion can occur. The consequences of defects in the clad are greatly reduced by the ability of uranium dioxide to retain fission products, including those which are gaseous or highly volatile.

Observations from several early Westinghouse pressurized water reactors as discussed in WCAP-8218-P-A (Reference 6) have shown that fuel pellets can densify under irradiation to a density higher than the manufactured values. Fuel densification and subsequent settling of the fuel pellets can result in local and distributed gaps in the fuel rods. The densification process is related to the elimination of very small as-fabricated porosity in the fuel during irradiation. Early fuels were intentionally manufactured to low initial density and were undersintered, which resulted in a large fraction of very small pores. Densification behavior in current fuel is controlled by improved manufacturing process controls and by specifying a nominal 95 percent initial fuel density, which results in reduced levels of small, densifying porosity.

The evaluation of fuel densification effects and the treatment of fuel swelling and fission gas release are described in WCAP-13589-A (Reference 8) and WCAP-10851-P-A (Reference 7).

4.2.3.3 Fuel Rod Performance

In the calculation of the steady-state performance of a nuclear fuel rod, the following interacting factors are considered:

- Clad creep and elastic deflection
- Pellet density changes, thermal expansion, gas release, and thermal properties as a function of temperature and fuel burnup
- Internal pressure as a function of fission gas release, rod geometry, and temperature distribution

These effects are evaluated using fuel rod design models, as discussed in WCAP-15063-P-A, Revision 1 (Reference 21) and WCAP-10851-P-A (Reference 7), that include appropriate models for time dependent fuel densification. With these interacting factors considered, the model determines the fuel rod performance characteristics for a given rod geometry, power history, and axial power shape. In particular, internal gas pressure, fuel and clad temperatures, and clad

deflections are calculated. The fuel rod is divided into several axial sections and radially into a number of annular zones. Fuel density changes are calculated separately for each segment. The effects are integrated to obtain the internal rod pressure.

The initial rod internal pressure is selected to delay fuel/clad mechanical interaction and to avoid the potential for clad flattening. It is limited, however, by the design criteria for the rod internal pressure, as discussed in subsection 4.2.1.3.

The gap conductance between the pellet surface and the clad inner diameter is calculated as a function of the composition, temperature and pressure of the gas mixture, and the gap size or contact pressure between the clad and pellet. After computing the fuel temperature for each pellet zone, the fractional fission gas release is assessed using an empirical model derived from experimental data, as detailed in WCAP-15063-P-A, Revision 1(Reference 21) and WCAP-10851-P-A (Reference 7). The total amount of gas released is based on the average fractional release within each axial and radial zone and the gas generation rate, which, in turn, is a function of burnup. Finally, the gas released is summed over the zones, and the pressure is calculated.

The model shows close agreement in fit for a variety of published and proprietary data on fission gas release, fuel temperatures, and clad deflections, as detailed in WCAP-15063-P-A, Revision 1 (Reference 21) and WCAP-10851-P-A (Reference 7). These data include variations in power, time, fuel density, and geometry.

4.2.3.3.1 Fuel/Cladding Mechanical Interaction

One factor in fuel element duty is potential mechanical interaction of the fuel and clad. This fuel/clad interaction produces cyclic stresses and strains in the clad, and these, in turn, reduce clad life. The reduction of fuel/clad interaction is therefore a goal of design. The technology for using pre-pressurized fuel rods in Westinghouse pressurized water reactors has been developed to further this objective.

The gap between the fuel and clad is initially sufficient to prevent hard contact between the two. However, during power operation a gradual compressive creep of the clad onto the fuel pellet occurs due to the external pressure exerted on the rod by the coolant. Clad compressive creep eventually results in fuel/clad contact. Once fuel/clad contact occurs, changes in power level result in changes in clad stresses and strains. By using pre-pressurized fuel rods to partially offset the effect of the coolant external pressure, the rate of clad creep toward the surface of the fuel is reduced. Fuel rod pre-pressurization delays the time at which fuel/clad contact occurs and, hence, significantly reduces the extent of cyclic stresses and strains experienced by the clad both before and after fuel/clad contact. These factors result in an increase in the fatigue life margin of the clad and lead to greater clad reliability.

A two-dimensional (r,θ) finite element model has been established to investigate the effects of radial pellet cracks on stress concentrations in the clad. Stress concentration herein is defined as the difference between the maximum clad stress in the θ direction and the mean clad stress. The first case has the fuel and clad in mechanical equilibrium; and, as a result, the stress in the clad is

close to zero. In subsequent cases the pellet power is increased in steps and the resultant fuel thermal expansion imposes tensile stress in the clad.

In addition to uniform clad stresses, stress concentrations develop in the clad adjacent to radial cracks in the pellet. These radial cracks have a tendency to open during a power increase, but the frictional forces between fuel and clad oppose the opening of these cracks and result in localized increases in clad stress. As the power is further increased, large tensile stresses exceed the ultimate tensile strength of uranium dioxide and additional cracks in the fuel pellet are created, limiting the magnitude of the stress concentration in the clad.

As part of the standard fuel rod design analysis, the maximum stress concentration evaluated from finite element calculations is added to the volume-averaged effective stress in the clad as determined from one-dimensional stress/strain calculations. The resultant clad stress is then compared to the temperature-dependent cladding yield stress to confirm that the stress/strain criteria are satisfied.

The transient evaluation method is described in the following paragraphs.

Pellet thermal expansion due to power increases is considered the only mechanism by which significant stresses and strains can be imposed on the clad.

Power increases in commercial reactors can result from fuel shuffling (for example, region 3 positioned near the core center for cycle 2 operation after operating near the periphery during cycle 1), reactor power escalation following extended reduced power operation, and full-length control rod movement. In the mechanical design model, lead rods are depleted using best-estimate power histories as determined by core physics calculations. During burnup, the amount of diametral gap closure is evaluated based upon the pellet expansion cracking model, clad creep model, and fuel swelling model. At various times during the depletion, the power is increased locally in the rod to the burnup-dependent attainable power density as determined by core physics calculations. The radial, tangential, and axial clad stresses resulting from the power increase are combined into a volume average effective clad stress.

The von Mises criterion is used to determine whether the clad yield stress has been exceeded. This criterion states that an isotropic material in multi-axial stress will begin to yield plastically when the effective stress exceeds the yield stress as determined by an axial tensile test. The yield stress correlation is that for irradiated cladding, since fuel/clad interaction occurs at high burnup. In applying this criterion, the effective stress is increased by an allowance which accounts for stress concentrations in the clad adjacent to radial cracks in the pellet, prior to the comparison with the yield stress. This allowance was evaluated using a two-dimensional (r,θ) finite element model.

Slow transient power increases can result in large clad strains without exceeding the clad yield stress because of clad creep and stress relaxation. Therefore, in addition to the yield stress criterion, a criterion on allowable clad strain is necessary. Based upon high strain rate burst and tensile test data on irradiated tubing, one percent strain was determined to be a conservative lower limit on irradiated clad ductility and that was adopted as a design criterion.

In addition to the mechanical design models and design criteria, the AP1000 fuel rod design relies on performance data accumulated through transient power test programs in experimental and commercial reactors, and through normal operation in commercial reactors.

It is recognized that a possible limitation to the satisfactory behavior of the fuel rods in a reactor subjected to daily load follow is the failure of the cladding by low-cycle strain fatigue. During their normal residence time in the reactor, the fuel rods may be subjected to on the order of 1000 load follow cycles, with typical changes in power level from 50 to 100 percent of their steady-state values.

The assessment of the fatigue life of the fuel rod cladding is subjected to considerable uncertainty because of the difficulty of evaluating the strain range which results from the cyclic interaction of the fuel pellets and cladding. This difficulty arises, for example, from such highly unpredictable phenomena as pellet cracking, fragmentation, and relocation. Westinghouse investigated this particular phenomenon both analytically and experimentally. Strain fatigue tests on irradiated and nonirradiated hydrided Zircaloy-4 cladding were performed. These tests permitted the definition of a conservative fatigue-life limit and recommendation of a methodology to treat the strain fatigue evaluation of the Westinghouse-referenced fuel rod designs. (See WCAP-9500-P-A, Reference 15.)

Successful load follow operation has been performed on several reactors. There was no significant coolant activity increase that could be associated with the load follow mode of operation.

The Westinghouse analytical approach to strain fatigue is based on a comprehensive review of the available strain fatigue models. The review included the Langer-O'Donnell model (Reference 16) the Yao-Munse model, and the Manson-Halford model. Upon completion of this review, and using the results of the Westinghouse experimental programs as documented in WCAP-9500-P-A (Reference 15), it was concluded that the approach defined by Langer-O'Donnell would be retained and the empirical factors of their correlation modified to conservatively bound the results of the Westinghouse testing program.

The design equations followed the concept for the fatigue design criterion according to the ASME Code, Section III:

- The calculated pseudo stress amplitude (S_a) has to be multiplied by a factor of two to obtain the allowable number of cycles (N_f).

- The allowable cycles for a given S_a is five percent of N_f or a safety factor of 20 on cycles.

The lesser of the two allowable numbers of cycles is selected. The cumulative fatigue life fraction is then computed as:

$$\sum_{1}^{k} \frac{n_k}{N_{f\,k}} \leq 1$$

where:

n_k = number of diurnal cycles of mode k.

N_{fk} = number of allowable cycles.

4.2.3.3.2 Irradiation Experience

Westinghouse fuel operational experience is presented in WCAP-8183 (Reference 3). Additional test assembly and test rod experience is given in WCAP-10125-P-A (Reference 2).

4.2.3.3.3 Fuel and Cladding Temperature

The methods used for evaluation of fuel rod temperatures are presented in subsection 4.4.2.11.

4.2.3.3.4 Potentially Damaging Temperature Effects During Transients

The fuel rod experiences many operational transients (intentional maneuvers) during its residence in the core. A number of thermal effects must be considered when analyzing the fuel rod performance.

The clad can be in contact with the fuel pellet at some time in the fuel lifetime. Clad/pellet interaction occurs if the fuel pellet temperature is increased after the clad is in contact with the pellet. Clad/pellet interaction is discussed in subsection 4.2.3.3.1.

Clad flattening has been observed in some operating power reactors. This is no longer a concern because clad flattening is precluded during the fuel residence in the core (subsection 4.2.3.1) by the use of stable fuel.

Potential differential thermal expansion between the fuel rods and the guide thimbles during a transient is considered in the design. Excessive bowing of the fuel rods is precluded because the grid assemblies allow axial movement of the fuel rods relative to the grids. Specifically, thermal expansion of the fuel rods is considered in the grid design so that axial loads imposed on the fuel rods during a thermal transient will not result in excessively bowed fuel rods.

4.2.3.3.5 Fuel Element Burnout and Potential Energy Release

As discussed in subsection 4.4.2.2, the core is protected from departure from nucleate boiling over the full range of possible operating conditions. In the extremely unlikely event that departure from nucleate boiling should occur, the clad temperature will rise due to the steam blanketing at the rod surface and the consequent degradation in heat transfer. During this time there is a potential for chemical reaction between the cladding and the coolant. However, because of the relatively good film boiling heat transfer following departure from nucleate boiling, the energy release resulting from this reaction is insignificant compared to the power produced by the fuel.

4.2.3.3.6 Coolant Flow Blockage Effects on Fuel Rods

The coolant flow blockage effects on fuel rods are presented in subsection 4.4.4.7.

4.2.3.4 Spacer Grids

The coolant flow channels are established and maintained by the structure composed of grids and guide thimbles. The lateral spacing between fuel rods is provided and controlled by the support dimples of adjacent grid cells. Contact of the fuel rods on the dimples is maintained through the clamping force of the grid springs. Lateral motion of the fuel rods is opposed by the spring force and the internal moments generated between the spring and the support dimples. Grid testing is discussed in WCAP-8236 (Reference 17) and WCAP-10444-P-A (Reference 11).

4.2.3.5 Fuel Assembly

4.2.3.5.1 Stresses and Deflections

The fuel assembly component stress levels are limited by the design. For example, stresses in the fuel rod due to thermal expansion and zirconium alloy irradiation growth are limited by the relative motion of the rod as it slips over the grid spring and dimple surfaces. Clearances between the fuel rod ends and nozzles are provided so that zirconium alloy irradiation growth does not result in rod end interference. Stresses in the fuel assembly caused by tripping of the rod cluster control assembly have little influence on fatigue usage margin because of the small number of events during the life of an assembly. Assembly components and prototype fuel assemblies made from production parts have been subjected to structural tests to verify that the design bases requirements are met.

The fuel assembly design loads for shipping have been established at 4 g axial and 6 g lateral. Accelerometers are permanently placed in the shipping cask to monitor and detect fuel assembly accelerations that would exceed the criteria. Experience indicates that loads that exceed the allowable limits rarely occur. Exceeding the limits requires reinspection of the fuel assembly for damage. Tests on various fuel assembly components, such as the grid assembly, sleeves, inserts, and structure joints, have been performed to confirm that the shipping design limits do not result in impairment of fuel assembly function. Seismic analysis methodology of the fuel assembly is presented in WCAP-8236 (Reference 17), WCAP 9401-P-A (Reference 18), and WCAP-10444-P-A (Reference 11).

To demonstrate that the fuel assemblies will maintain a geometry that is capable of being cooled under the worst-case accident Condition IV event, a plant specific or bounding seismic analysis is performed.

The fuel assembly response resulting from safe shutdown earthquake condition is analyzed using time-history numerical techniques. The vessel motion for this type of event primarily causes lateral loads on the reactor core. Consequently, the methodology and analytical procedures as described in WCAP-8236 (Reference 17) and WCAP-9401-P-A (Reference 18) are used to assess the fuel assembly deflections and impact forces.

The motions of the reactor internals upper and lower core plates and the core barrel at the upper core plate elevation, which are simultaneously applied to simulate the reactor core input motion, are obtained from the time-history analysis of the reactor vessel and internals. The fuel assembly response, namely the displacements and impact forces, is obtained with the reactor core model. Similar dynamic analyses of the core were performed using reactor internals motions indicative of

the postulated pipe rupture. Scenarios regarding breaches in the pressure boundary are investigated to determine the most limiting structural loads for the fuel assembly. The application of leak-before-break limits the size of the pipe rupture loads for which the fuel assemblies must be analyzed. The pipe rupture used in the fuel assembly analysis is the largest pipe connected to the reactor coolant system which does not satisfy the leak-before-break criteria. Subsection 3.6.3 discusses mechanistic pipe break.

4.2.3.5.1.1 Grid Analyses

The maximum grid impact force obtained from seismic analyses is less than the allowable grid strength. With respect to the guidelines of Appendix A of the Standard Review Plan, Section 4.2, Westinghouse has demonstrated that a simultaneous safe shutdown earthquake and pipe rupture event is highly unlikely. The fatigue cycles, crack initiation, and crack growth due to normal operating and seismic events will not realistically lead to a pipe rupture. More information is available in WCAP-9283 (Reference 19).

Based on the deterministic fracture mechanics evaluation of small flaws in piping components, Westinghouse has demonstrated that the dynamic affects of a large pipe rupture in the primary coolant piping system for the AP1000 design does not have to be considered.

A design basis for the piping design in the AP1000 is that the reactor coolant loop and surge lines will satisfy the leak-before-break criteria for mechanistic pipe break. In addition, the piping connected to the reactor coolant system that is six inch nominal diameter or larger is evaluated for leak-before-break. The result of a pipe leakage event consistent with the mechanistic pipe break evaluation would be to impose insignificant asymmetric loadings on the reactor core system. Thus, fuel assembly grid loads due to large pipe ruptures are unrealistic and, as such, are not included in the analysis.

The pressure boundary integrity for numerous branch lines is analyzed to determine the most limiting break of a line not qualified for leak-before-break for the dynamic loading of the reactor core. Grid loads resulting from a combined seismic and pipe rupture event do not cause unacceptable grid deformation as to preclude a core coolable geometry.

4.2.3.5.1.2 Nongrid Analyses

The stresses induced in the various fuel assembly nongrid components are assessed based on the most limiting seismic condition. The fuel assembly axial forces resulting from the hold-down spring load together with its own weight distribution are the primary sources of the stresses in the guide thimbles and fuel assembly nozzles. The fuel rod accident induced stresses, which are generally very small, are caused by bending due to the fuel assembly deflections during a seismic event. The seismic-induced stresses are compared with the allowable stress limits for the fuel assembly major components. The component stresses, which include normal operating stresses, are below the established allowable limits. Consequently, the structural designs of the fuel assembly components are acceptable for the design basis accident conditions for the AP1000.

4.2.3.5.2 Dimensional Stability

Localized yielding and slight deformation in some fuel assembly components are allowed to occur during a Condition III or IV event. The maximum permanent deflection, or deformations, do not result in any violation of the functional requirements of the fuel assembly.

4.2.3.6 Reactivity Control Assemblies and Burnable Absorber Rods

4.2.3.6.1 Internal Pressure and Cladding Stresses during Normal, Transient, and Accident Conditions

The designs of the burnable absorber and source rods provide a sufficient cold void volume to accommodate the internal pressure increase during operation. This is not a concern for the rod cluster control assembly absorber rod or gray rod cluster assembly rodlets because no gas is released by the silver-indium-cadmium absorber material.

For the discrete burnable absorber rod, there is sufficient cold void volume to limit the internal pressure to a value, which satisfies the design criteria. For the source rods, a void volume is provided within the rod to limit the maximum internal pressure increase at end-of-life. Figures 4.2-14 and 4.2-15 detail the primary and secondary source assemblies.

During normal transient and accident conditions, the void volume limits the internal pressures to values that satisfy the criteria in subsection 4.2.1.6. These limits are established not only to prevent the peak stresses from reaching unacceptable values, but also to limit the amplitude of the oscillatory stress component in consideration of the fatigue characteristics of the materials.

Rod, guide thimble, and dashpot flow analyses indicate that the flow is sufficient to prevent coolant boiling within the guide thimble. Therefore, clad temperatures at which the clad material has adequate strength to resist coolant operating pressures and rod internal pressures are maintained.

4.2.3.6.2 Thermal Stability of the Absorber Material, Including Changes and Thermal Expansion

The radial and axial temperature profiles within the source and absorber rods are determined by considering gap conductance, thermal expansion, neutron or gamma heating of the contained material as well as gamma heating of the clad.

The maximum temperatures of the silver-indium-cadmium control rod absorber material are calculated and found to be significantly less than the material melting point and found to occur axially at only the highest flux region. The mechanical and thermal expansion properties of the silver-indium-cadmium absorber material are discussed in WCAP-9179 (Reference 4).

The maximum temperature of the alumina-boron carbide burnable absorber pellet is expected to be less than 1200°F which takes place following the initial power ascent. As the operating cycle proceeds, the burnable absorber pellet temperature decreases due to a reduction in heat generation due to boron depletion and better gap conduction as the helium produced diffuses into the gap.

Sufficient diametral and end clearances have been provided in the neutron absorber, burnable absorber, and source rods to accommodate the relative thermal expansions between the enclosed material and the surrounding clad and end plug.

4.2.3.6.3 Irradiation Stability of the Absorber Material, Taking into Consideration Gas Release and Swelling

The irradiation stability of the silver-indium-cadmium absorber material is discussed in WCAP-9179 (Reference 4). Irradiation produces no deleterious effects in the absorber material.

As mentioned in subsection 4.2.3.6.1, gas release is not a concern for the control rod material because no gas is produced by the absorber material. Sufficient diametral and end clearances are provided to accommodate any potential expansion and/or swelling of the absorber material.

The alumina-boron carbide burnable absorber pellets are designed such that gross swelling or crumbling of the pellets is not predicted to occur during reactor operation. Some minor cracking of the pellets may occur, but this cracking should not affect the overall absorber and stack integrity.

4.2.3.6.4 Potential for Chemical Interaction, Including Possible Waterlogging Rupture

The structural materials selected have good resistance to irradiation damage and are compatible with the reactor environment.

Corrosion of the materials exposed to the coolant is quite low, and proper control of chloride and oxygen in the coolant minimizes potential for the occurrence of stress corrosion. The potential for the interference with rod cluster control assembly movement due to possible corrosion phenomena is very low.

Waterlogging rupture is not a failure mechanism associated with the AP1000 control rods. Furthermore, a breach of the cladding for any postulated reason does not result in serious consequences.

The silver-indium-cadmium absorber material is relatively inert and will remain inert even when subjected to high coolant velocity regions. Rapid loss of reactivity control material will not occur. Test results detailed in WCAP-9179 (Reference 4) concluded that additions of indium and cadmium to silver, in the amounts to form the silver-indium-cadmium absorber material composition, result in small corrosion rates.

For the discrete burnable absorber, in the unlikely event that the zirconium alloy clad is breached, the boron carbide in the affected rod(s) could be leached out by the coolant water. If this occurred early, in-core instruments could detect large peaking factor changes, and corrective action would be taken, if warranted. A postulated clad breach after substantial irradiation would have no significant effect on peaking factors since the boron will have been depleted. Breaching of the zirconium alloy clad by internal hydriding is not expected due to moisture controls employed during fabrication. Rods of this design have performed very well with no failures observed.

4.2.4 Testing and Inspection Plan

4.2.4.1 Quality Assurance Program

The Quality Assurance Program Plan of the Westinghouse Commercial Nuclear Fuel Division for the AP1000 is summarized in Chapter 17.

The program provides for control over activities affecting product quality, commencing with design and development and continuing through procurement, materials handling, fabrication, testing and inspection, storage, and transportation. The program also provides for the indoctrination and training of personnel and for the auditing of activities affecting product quality through a formal auditing program.

Westinghouse drawings and product, process, and material specifications identify the inspections to be performed.

4.2.4.2 Quality Control

Quality control philosophy is generally based on the following inspections being performed to a 95 percent confidence that at least 95 percent of the product meets specification, unless otherwise noted.

4.2.4.2.1 Fuel System Components and Parts

The characteristics inspected depend on the component parts. The quality control program includes dimensional and visual examinations, check audits of test reports, material certification, and nondestructive examination, such as X-ray and ultrasonic.

The material used in the AP1000 core is accepted and released by Quality Control.

4.2.4.2.2 Pellets

Inspection is performed for dimensional characteristics such as diameter, density, length, and squareness of ends. Additional visual inspections are performed for cracks, chips, and surface conditions according to approved standards.

Density is determined in terms of weight per unit length and is plotted on zone charts used in controlling the process. Chemical analyses are taken on a specified sample basis throughout pellet production.

4.2.4.2.3 Rod Inspection

Fuel rod, rod cluster control rod, discrete burnable absorber rod, and source rod inspections consists of the following nondestructive examination techniques and methods, as applicable:

- Each rod is leak tested using a calibrated mass spectrometer, with helium being the detectable gas.

- Rod welds are inspected by ultrasonic test or X-ray in accordance with a qualified technique and Westinghouse specifications meeting the requirements of ASTM-E-142-86 (Reference 20).

- Rods are dimensionally inspected prior to final release. The requirements include such items as length, camber, and visual appearance.

- Fuel rods are inspected by gamma scanning or other approved methods, as discussed in subsection 4.2.4.5, to confirm proper plenum dimensions.

- Fuel rods are inspected by gamma scanning, or other approved methods, as discussed in subsection 4.2.4.5, to confirm that no significant gaps exist between pellets.

- Fuel rods are actively and/or passively gamma scanned to verify enrichment control prior to acceptance for assembly loading.

- Traceability of rods and associated rod components is established by quality control.

4.2.4.2.4 Assemblies

Each fuel rod, control rod, burnable absorber rod and source rod assembly is inspected for compliance with drawing and/or specification requirements. Other in-core control component inspection and specification requirements are given in subsection 4.2.4.4.

4.2.4.2.5 Other Inspections

The following inspections are performed as part of the routine inspection operation:

- Tool and gauge inspection and control, including standardization to primary and/or secondary working standards. Tool inspection is performed at prescribed intervals on serialized tools. Complete records are kept of calibration and conditions of tools.

- Audits are performed of inspection activities and records to confirm that prescribed methods are followed and that records are correct and properly maintained.

- Surveillance inspection, where appropriate, and audits of outside contractors are performed to confirm conformance with specified requirements.

4.2.4.2.6 Process Control

To prevent the possibility of mixing enrichments during fuel manufacture and assembly, strict enrichment segregation and other process controls are exercised.

The uranium dioxide powder is kept in sealed containers. The contents are fully identified both by descriptive tagging and unique barcode numbers. A quality control identification tag completely describing the contents is affixed to the containers before transfer to powder storage. Isotopic content is confirmed by analysis.

Powder withdrawal from storage can be made by only one authorized group, which directs the powder to the correct pellet production line. The pellet production lines are physically separated from each other, and pellets of only a single nominal enrichment and density are produced in a given production line at any given time.

Finished pellets are placed on trays identified with the same color code as the powder containers and transferred to segregated storage racks within the confines of the pelleting area. Samples from each pellet lot are tested for isotopic content and impurity levels prior to acceptance by quality control. Physical barriers are used to prevent mixing of pellets of different nominal densities and enrichments in the pellet storage area. Unused powder and substandard pellets are returned to storage in the original color-coded containers.

Loading of pellets into the clad is performed in isolated production lines; only one density and enrichment (with possible exception for top and bottom (axial blanket) zones) are loaded on a line at a time.

A serialized traceability code is placed on each fuel tube, which identifies the contract and enrichment. The end plugs are inserted and then welded (in an inert gas atmosphere) to seal the tube. The fuel tube remains coded and traceability identified until just prior to installation in the fuel assembly.

Similar traceability is provided for wet annular burnable absorber, source, and control rods, as required.

4.2.4.3 Letdown Radiation Monitoring

Radiation monitoring of the reactor coolant is made by grab samples and laboratory analysis of the primary coolant. Refer to information presented in subsections 9.3.3 and 9.3.6, and Table 9.3.3-1.

4.2.4.4 In-core Control Component Testing and Inspection

Tests and inspections are performed on each reactivity control component to verify the mechanical characteristics. In the case of the rod cluster control assembly, prototype testing has been conducted. Manufacturing test/inspections and functional testing at the plant site are both performed.

During the component manufacturing phase, the following requirements apply to the reactivity control components to provide the proper functioning during reactor operation:

- Materials are procured to specifications to attain the desired standard of quality.

- Spider assemblies are proof-tested by applying a 5000-pound load to the spider body, so that approximately 310 pounds is applied to each vane. This proof load provides a bending moment at the spider body approximately equivalent to 1.4 times the load caused by the acceleration imposed by the control rod drive mechanism.

- Rods are checked for integrity by the applicable nondestructive methods described in subsection 4.2.4.2.3.

- To confirm proper fit with the fuel assembly, the rod cluster control, discrete burnable absorber, and source assemblies are installed in the fuel assembly and checked for binding in the dry condition.

The rod cluster control assemblies and gray rod cluster assemblies are also functionally tested, following core loading but prior to criticality, to demonstrate reliable operation of the assemblies. Each assembly is operated (and tripped) one time at full-flow/hot conditions. In addition, any assembly that has a drop time greater than a two sigma limit from the average rod drop time is subjected to additional rod drops to confirm drop time. Thus, each assembly is sufficiently tested to confirm proper functioning and operation.

To demonstrate continuous free movement of the rod cluster control assemblies, and gray rod cluster assemblies, and to provide acceptable core power distributions during operations, partial movement checks are performed on every assembly as required by the technical specifications. In addition, periodic drop tests of the assemblies are performed at each refueling shutdown to demonstrate continued ability to meet trip time requirements.

If a rod cluster control assembly and/or gray rod cluster assembly cannot be moved by its mechanism, adjustments in the boron concentration of the coolant provide that adequate shutdown margin will be achieved following a trip. Thus, inability to move one assembly can be tolerated. More than one inoperable assembly could be tolerated but would impose additional demands on the plant operator. Therefore, the number of inoperable assemblies has been limited to one.

4.2.4.5 Tests and Inspections by Others

For tests and inspections performed by others, Westinghouse reviews and approves the quality control procedures, and inspection plans to be utilized to confirm that they are equivalent to the description provided in subsections 4.2.4.1 through 4.2.4.4 and are performed properly to meet Westinghouse requirements.

4.2.4.6 Inservice Surveillance

As detailed in WCAP-8183 (Reference 3), significant 17x17 fuel assembly operating experience has been obtained. A surveillance program is expected to be established for the AP1000 for inspection of post-irradiated fuel assemblies. This surveillance program will establish the schedule, guidelines, and inspection criteria for conducting visual inspection of post-irradiated fuel assemblies and/or insert components. The surveillance program includes a quantitative visual examination of some discharged fuel assemblies from each refueling. This program also includes criteria for additional inspection requirements for post-irradiated fuel assemblies if unusual characteristics are noticed in the visual inspection or if plant instrumentation and subsequent laboratory analysis indicates gross failed fuel. The post-irradiated fuel surveillance program will address disposition of fuel assemblies and/or insert components receiving an unsatisfactory visual inspection. Those post-irradiated fuel assemblies receiving an unsatisfactory visual inspection are not reinserted into the core until a more detailed inspection and/or evaluation can be performed. Normally the fuel assemblies are taken to the spent fuel inspection station.

4.2.4.7 Onsite Inspection

Written procedures are used for the post-shipment inspection of the new fuel assemblies in addition to reactivity control and source components. Fuel handling procedures specify the sequence in which handling and inspection take place.

Loaded fuel containers, when received onsite, are externally inspected to confirm that labels and markings are intact and security seals are unbroken. After the containers are opened, the shock indicators attached to the suspended internals are inspected to determine whether movement during transit exceeded design limitations.

Following removal of the fuel assembly from the container in accordance with detailed procedures, the fuel assembly plastic wrapper is examined for evidence of damage. The polyethylene wrapper is then removed, and a visual inspection of the entire fuel assembly is performed.

Control rod, gray rod, secondary source rod and discrete burnable absorber rod assemblies are usually shipped in fuel assemblies. They are inspected prior to removal of the fuel assembly from the container. The control rod assembly is withdrawn a few inches from the fuel assembly to confirm free and unrestricted movement, and the exposed section is visually inspected for mechanical integrity, replaced in the fuel assembly, and stored with the fuel assembly. Control rod, secondary source or discrete burnable absorber assemblies may be stored separately or within fuel assemblies in the new fuel storage area.

4.2.5 Combined License Information

Combined License applicants referencing the AP1000 certified design will address changes to the reference design of the fuel, burnable absorber rods, rod cluster control assemblies, or initial core design from that presented in the DCD.

4.2.6 References

[*1. Davidson, S. L. (Ed.), "Fuel Criteria Evaluation Process," WCAP-12488-A (Proprietary) and WCAP-14204-A (Non-Proprietary), October 1994.*]*

2. Davidson, S. L. (Ed.) et al., "Extended Burnup Evaluation of Westinghouse Fuel," WCAP-10125-P-A (Proprietary) and WCAP-10126-NP-A (Non-Proprietary), December 1985.

3. "Operational Experience with Westinghouse Cores," WCAP-8183, (revised annually).

4. Beaumont, M. D., et al., "Properties of Fuel and Core Component Materials," WCAP-9179, Revision 1 (Proprietary) and WCAP-9224 (Non-Proprietary), July 1978.

5. Davidson, S. L., and Nuhfer, D. L. (Ed.), "VANTAGE+ Fuel Assembly Reference Core Report," WCAP-12610-P-A (Proprietary), June 1990 and WCAP-14342-A (Non-Proprietary), April 1995.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

6. Hellman, J. M., Ed, "Fuel Densification Experimental Results and Model for Reactor Application," WCAP-8218-P-A (Proprietary) and WCAP-8219-A (Nonproprietary), March 1975.

7. Weiner, R. A., et al., "Improved Fuel Performance Models for Westinghouse Fuel Rod Design and Safety Evaluations," WCAP-10851-P-A (Proprietary) and WCAP-11873-A (Nonproprietary), August, 1988.

8. Davidson, S. L. (Ed) et al., "Assessment of Clad Flattening and Densification Power Spike Factor Elimination in Westinghouse Nuclear Fuel," WCAP-13589-A (Proprietary) and WCAP-14297-A (Non-Proprietary), March 1995.

9. Risher, D., et al., "Safety Analysis for the Revised Fuel Rod Internal Pressure Design Basis," WCAP-8963-P-A (Proprietary), November 1976 and WCAP-8964-A (Non-Proprietary), August 1977.

10. Skarita, J., et al., "Westinghouse Wet Annular Burnable Absorber Evaluation Report," WCAP-10021-P-A, Revision 1 (Proprietary) and WCAP-10377-NP-A, Revision 2 (Non-Proprietary), October 1983.

11. Davidson, S. L. (Ed.) et al., "Reference Core Report VANTAGE 5 Fuel Assembly," WCAP-10444-P-A (Proprietary) and WCAP-10445-NP-A (Nonproprietary), September 1985.

12. ASTM-A-580-90, Specification for Stainless and Heat-resisting Steel Wire.

13. Demario, E. E., "Hydraulic Flow Test of the 17x17 Fuel Assembly," WCAP-8278 (Proprietary) and WCAP-8279 (Non-Proprietary), February 1974.

14. Skaritka, J. (Ed.), "Fuel Rod Bow Evaluation," WCAP-8691, Revision 1 (Proprietary) and WCAP-8692, Revision 1 (Non-Proprietary), July 1979.

15. Davidson, S. L. and Iorii, J. A., "Reference Core Report 17x17 Optimized Fuel Assembly," WCAP-9500-P-A (Proprietary) and WCAP-9500-A (Nonproprietary), May 1982.

16. O'Donnell, W. J., and Langer, B. F., "Fatigue Design Basis for Zircaloy Components," Nuclear Science and Engineering 20, pp 1-12, 1964.

17. Gesinski, L., and Chiang, D., "Safety Analysis of the 17x17 Fuel Assembly for Combined Seismic and Loss-of-Coolant Accident," WCAP-8236 (Proprietary) and WCAP-8288 (Nonproprietary), December 1973.

18. Davidson, S. L., et al., "Verification, Testing, and Analysis of the 17x17 Optimized Fuel Assembly," WCAP-9401-P-A (Proprietary) and WCAP-9402-A (Nonproprietary), August 1981.

19. Witt, F. J., Bamford, W. H., and Esselman, T. C., "Integrity of the Primary Piping Systems of Westinghouse Nuclear Power Plants During Postulated Seismic Events," WCAP-9283 (Nonproprietary), March 1978.

20. ASTM-E-142-86, Methods for Controlling Quality of Radiographic Testing.

21. Foster, J. P., et al., "Westinghouse Improved Performance Analysis and Design Model (PAD 4.0)," WCAP-15063-P-A, Revision 1 (Proprietary) and WCAP-15064-NP-A, Revision 1 (Non-Proprietary), July 2000.

22. George, R. A., et al., "Revised Clad Flattening Model," WCAP-8377 (Proprietary), July 1974.

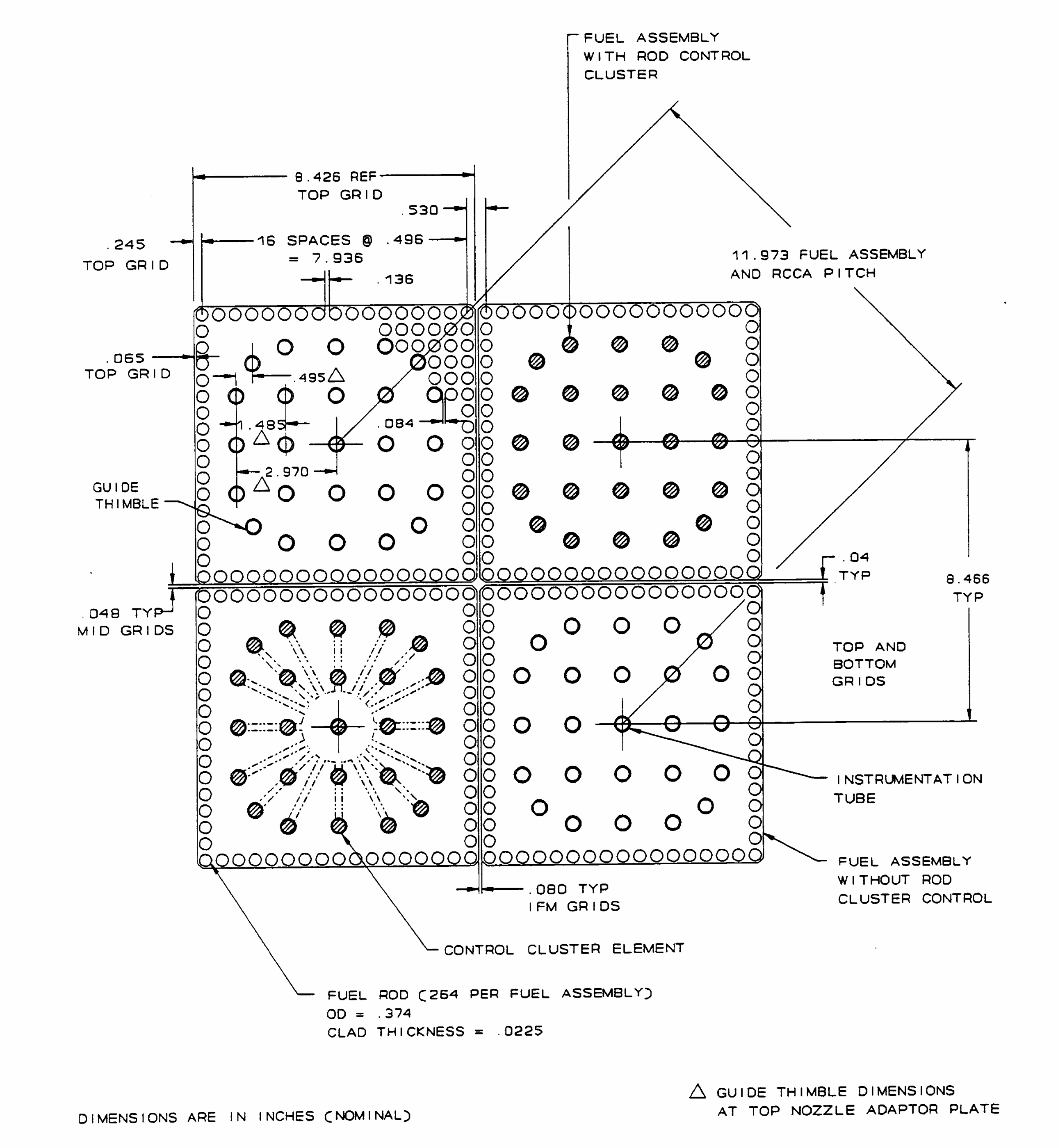


Figure 4.2-1

Fuel Assembly Cross-Section

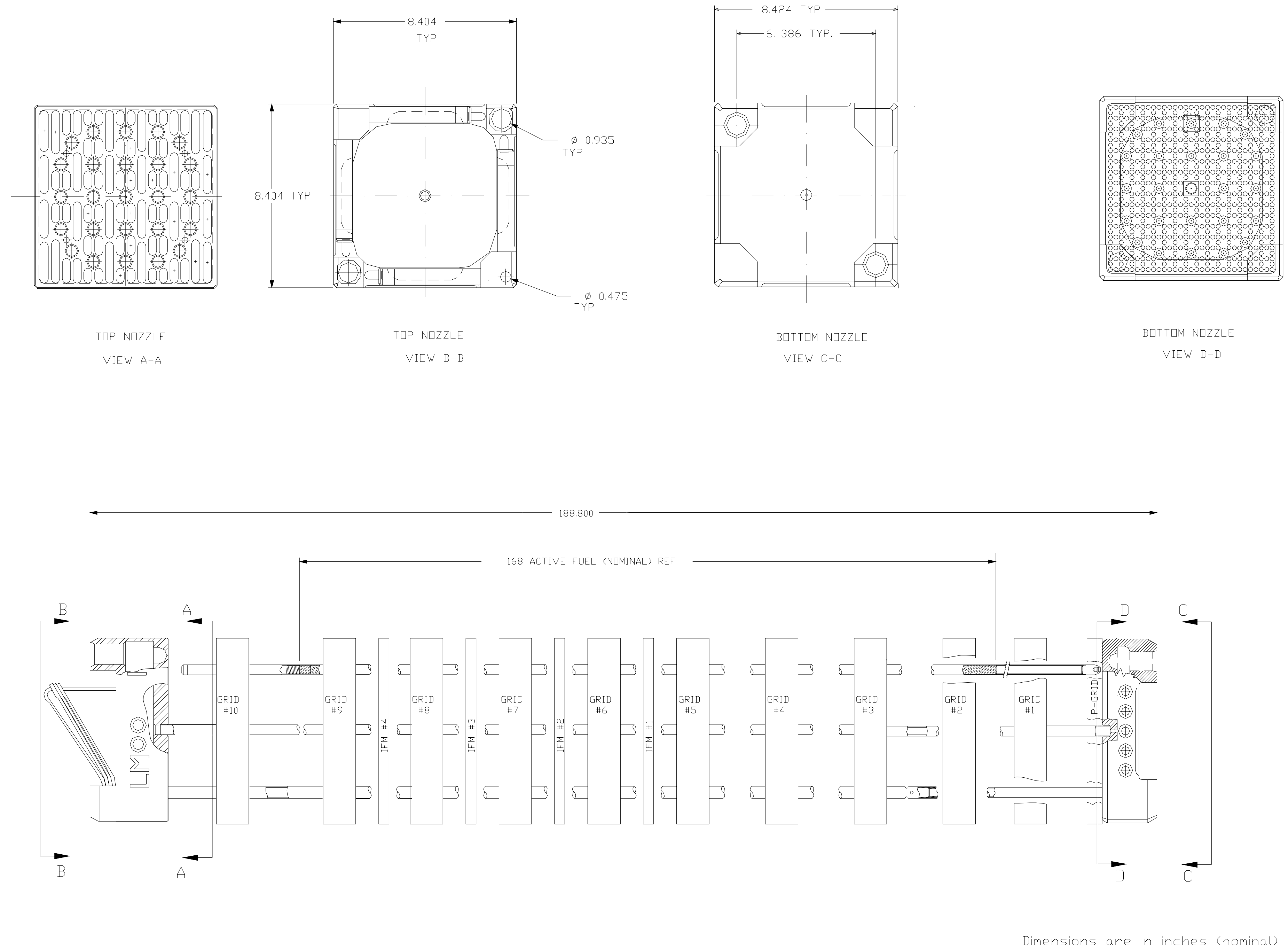


Figure 4.2-2

Fuel Assembly Outline

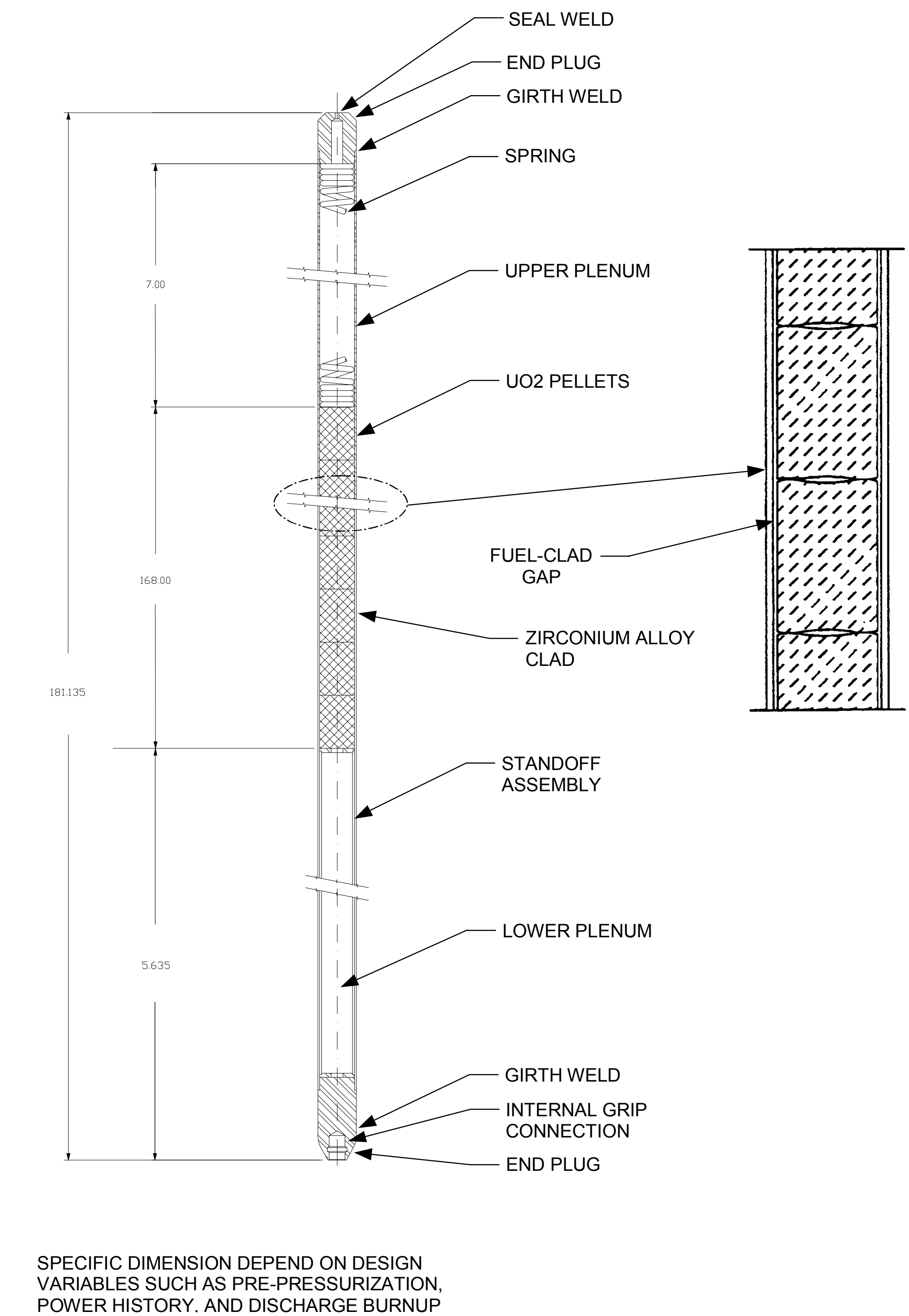


Figure 4.2-3

Fuel Rod Schematic

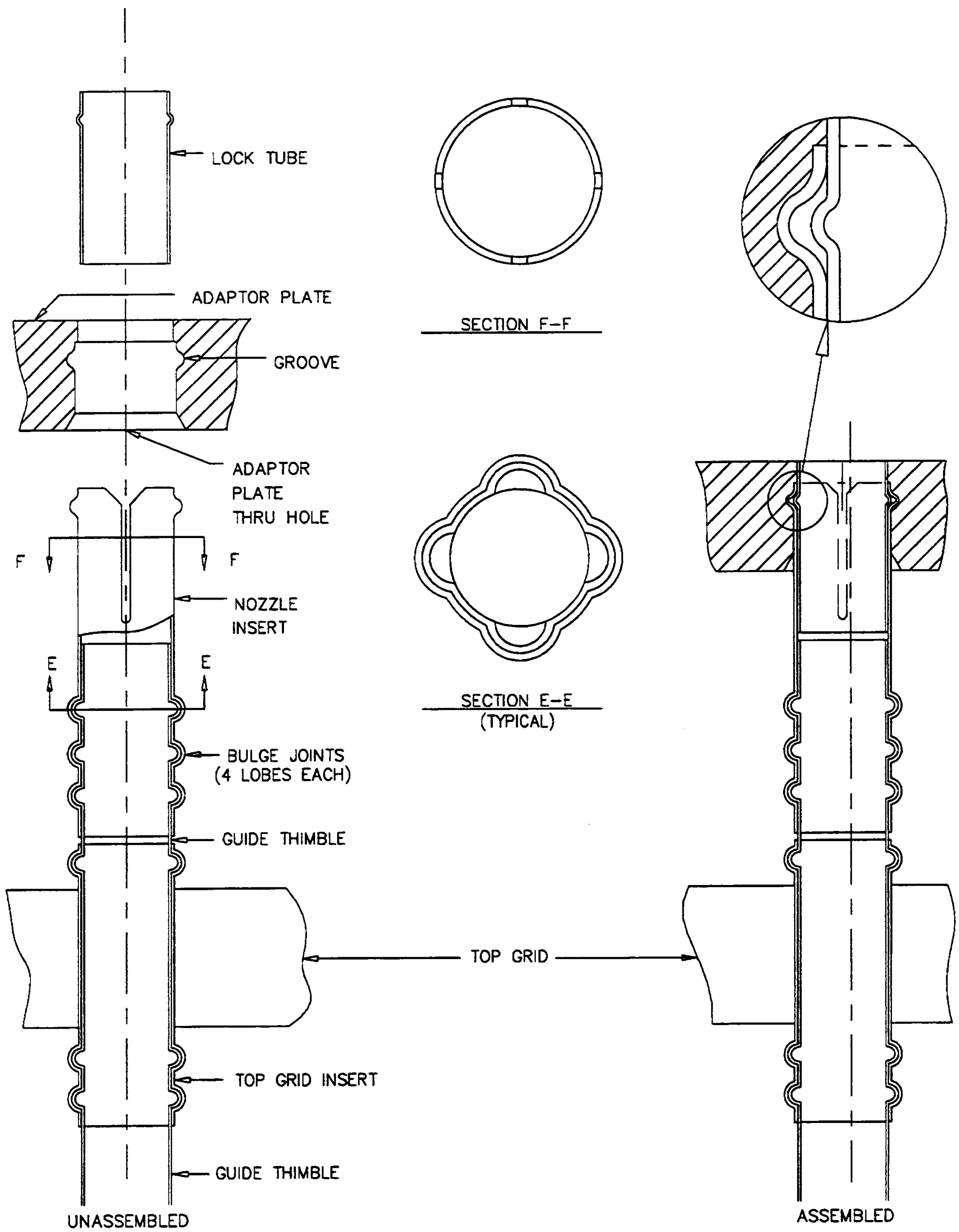


Figure 4.2-4

Top Grid Sleeve Detail

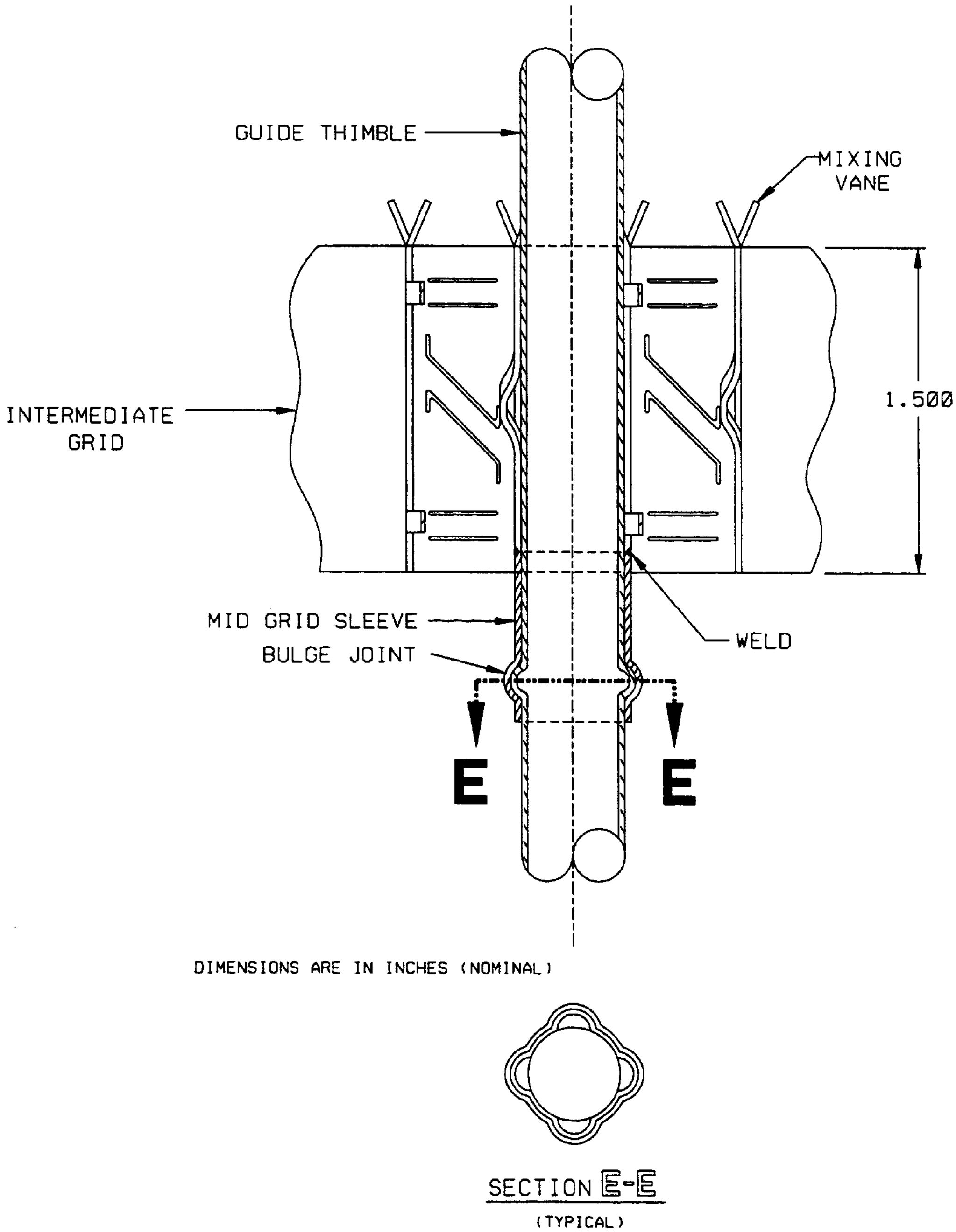


Figure 4.2-5

Intermediate Grid to Thimble Attachment Joint

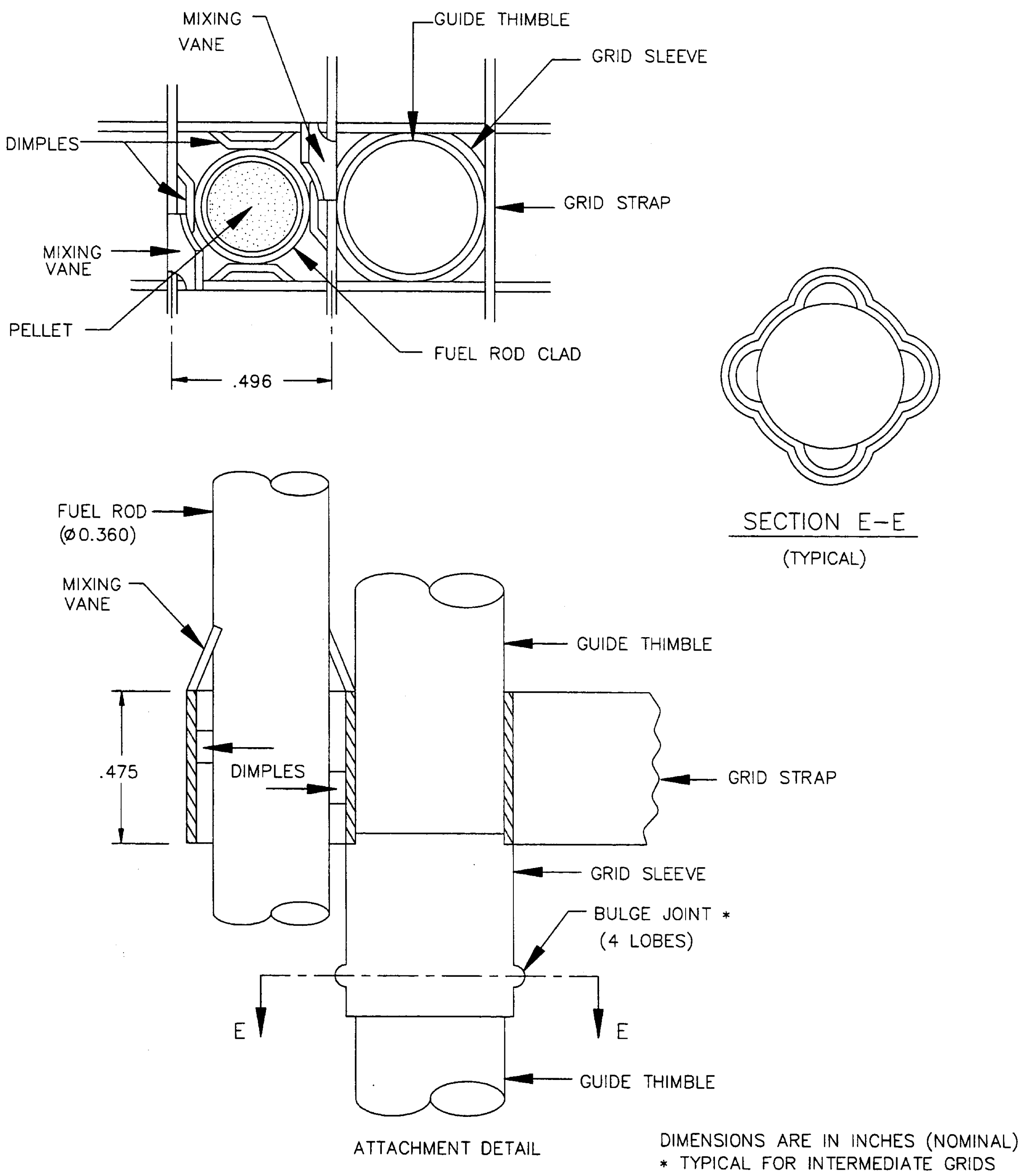


Figure 4.2-6

Intermediate Flow Mixer
Grid to Thimble Attachment

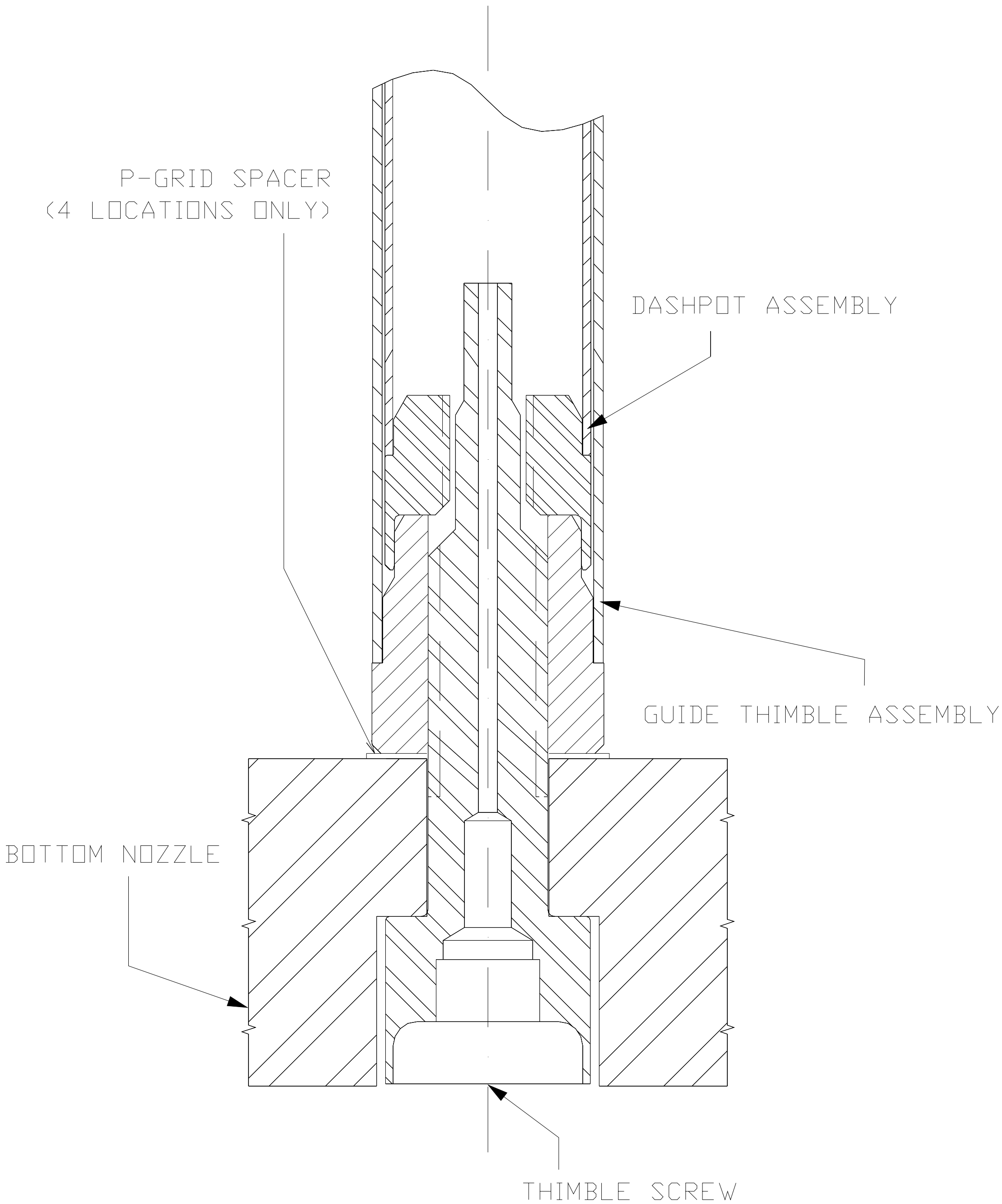


Figure 4.2-7

Grid Thimble to Bottom Nozzle Joint

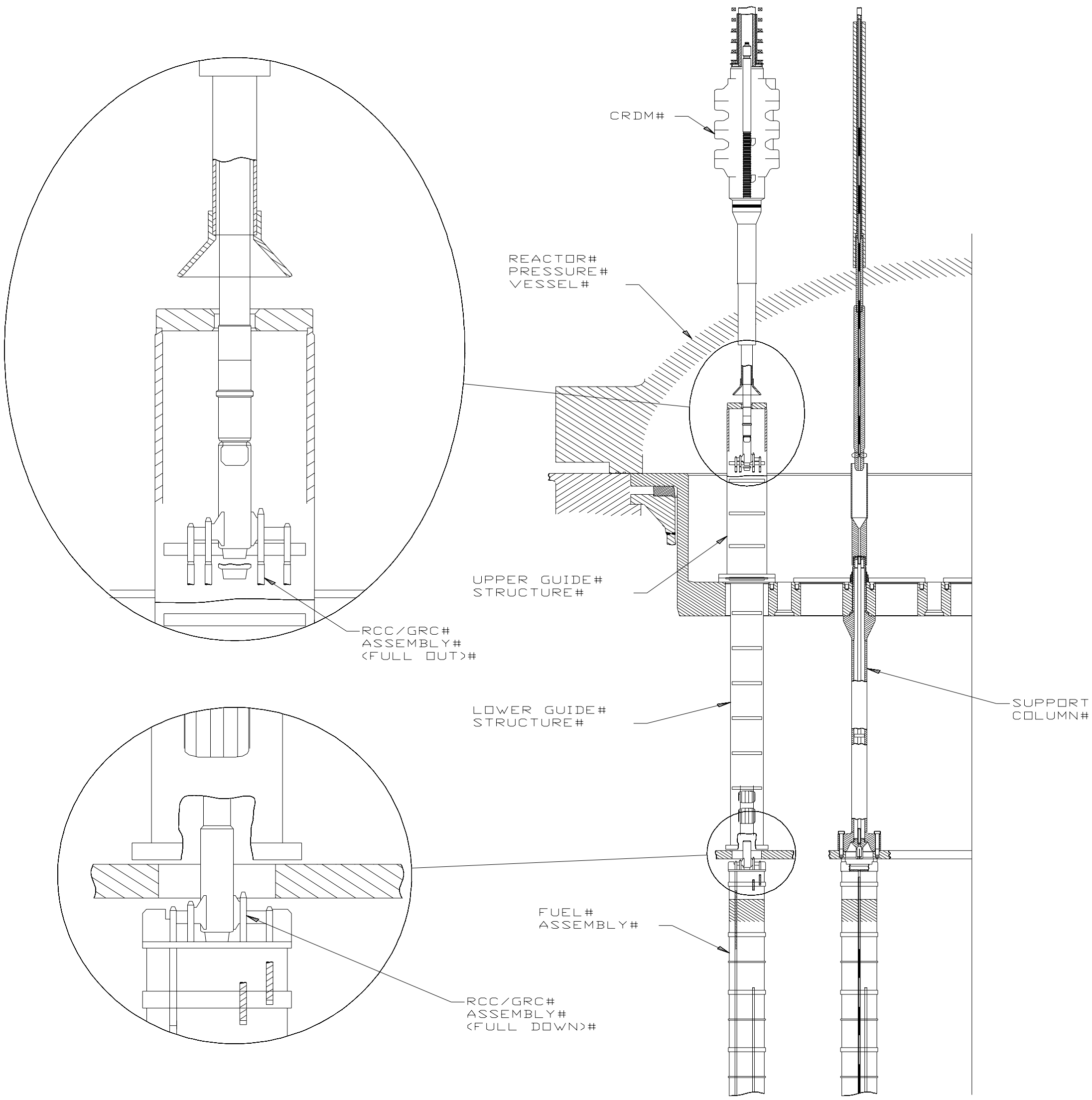


Figure 4.2-8

Rod Cluster Control and Drive Rod Assembly With Interfacing Components

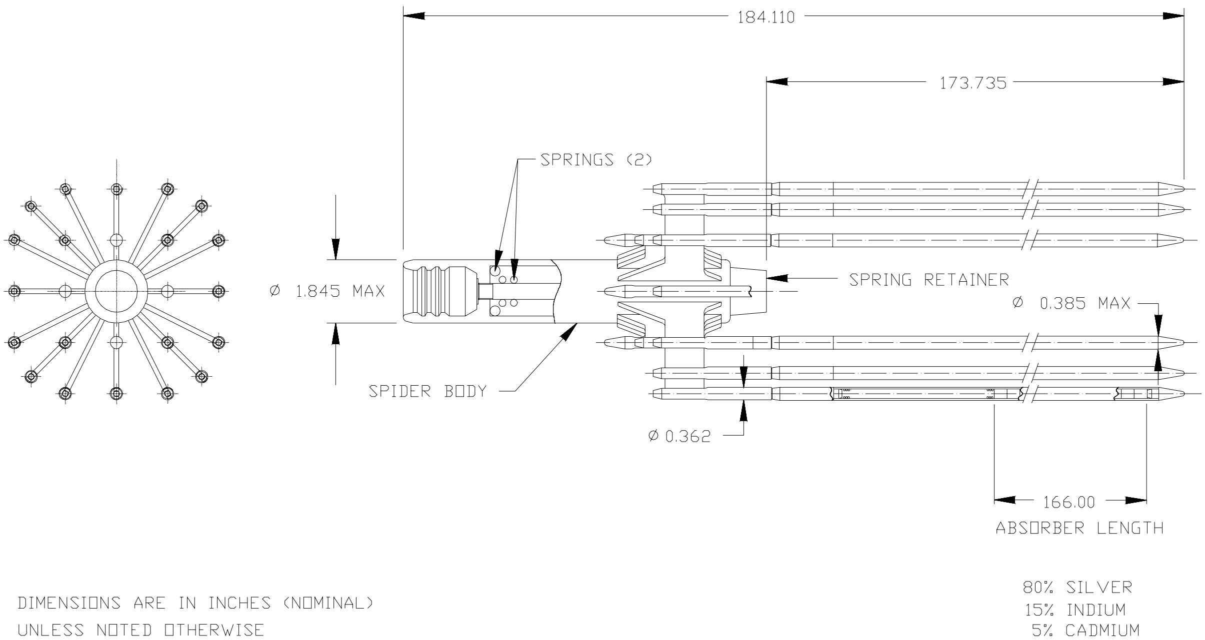


Figure 4.2-9

Rod Cluster Control Assembly

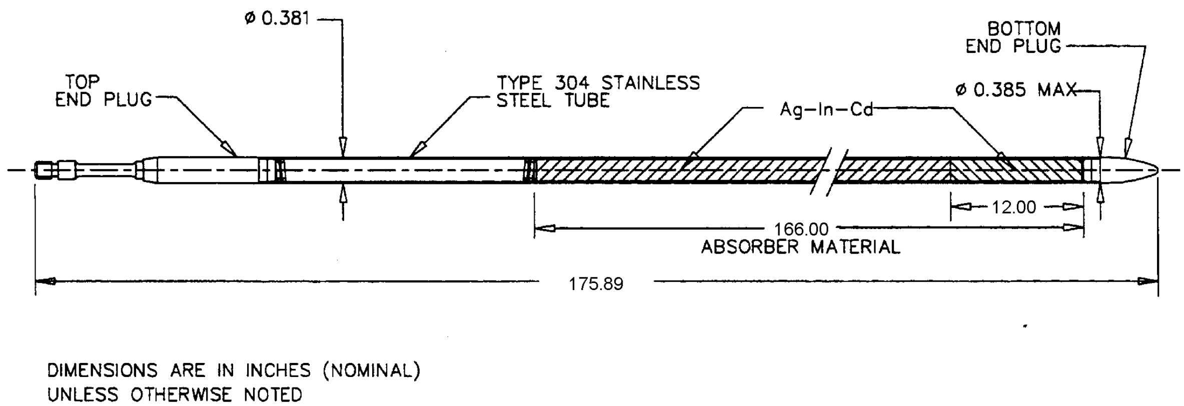


Figure 4.2-10

Absorber Rod Detail

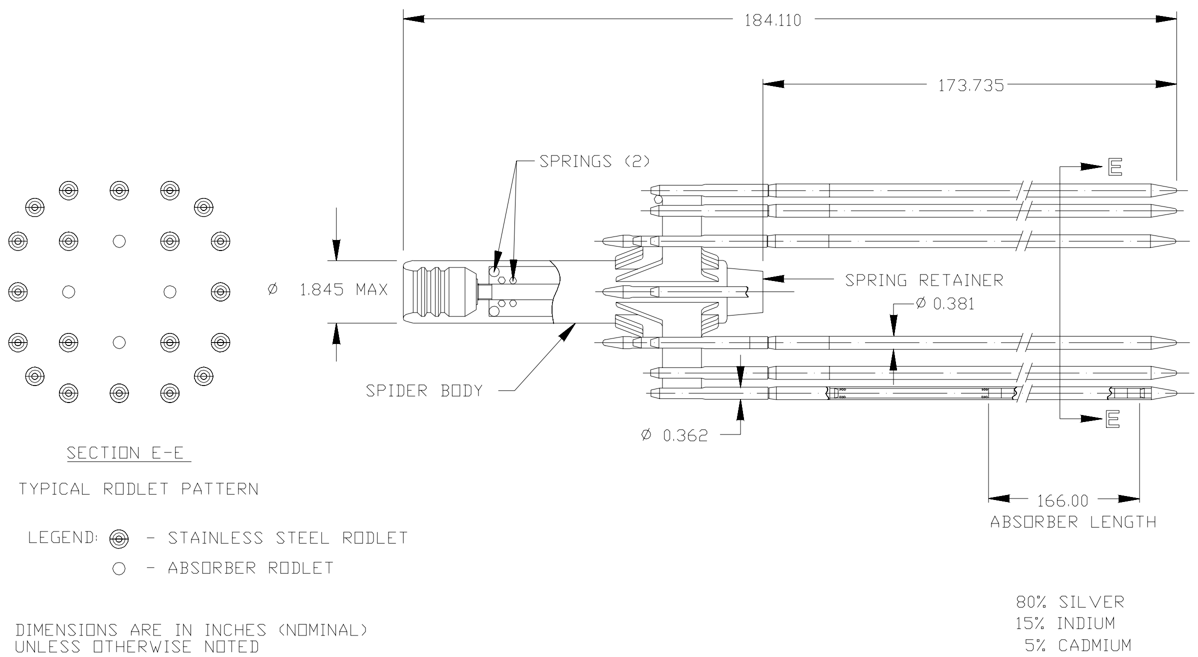


Figure 4.2-11

Gray Rod Cluster Assembly

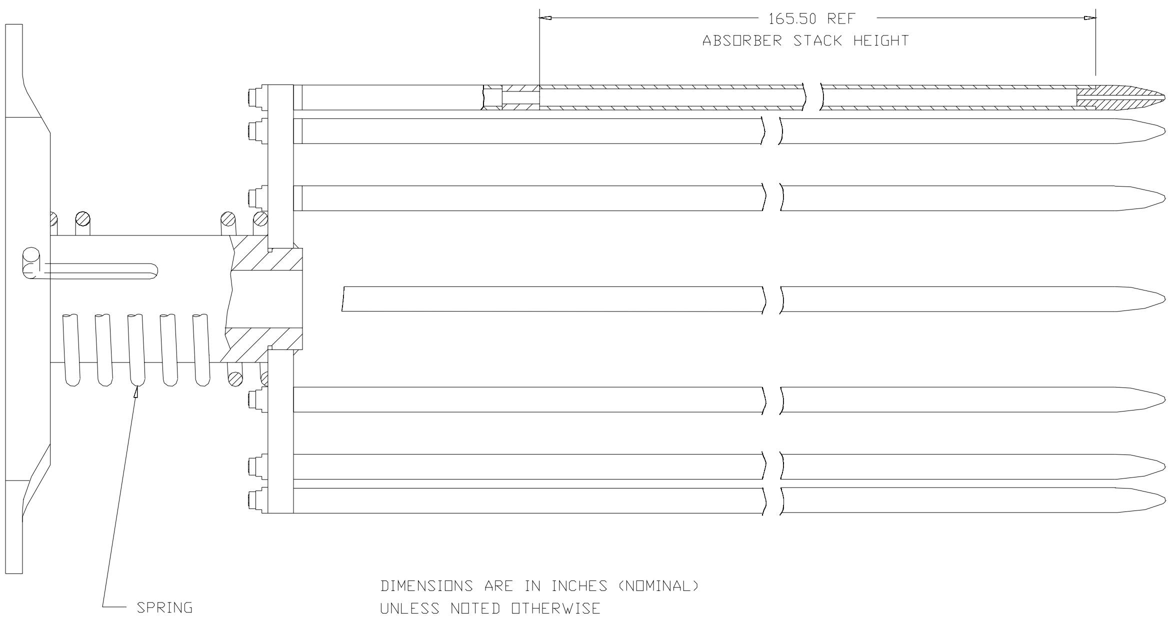


Figure 4.2-12

Discrete Burnable Absorber Assembly

Figure 4.2-13 not used.

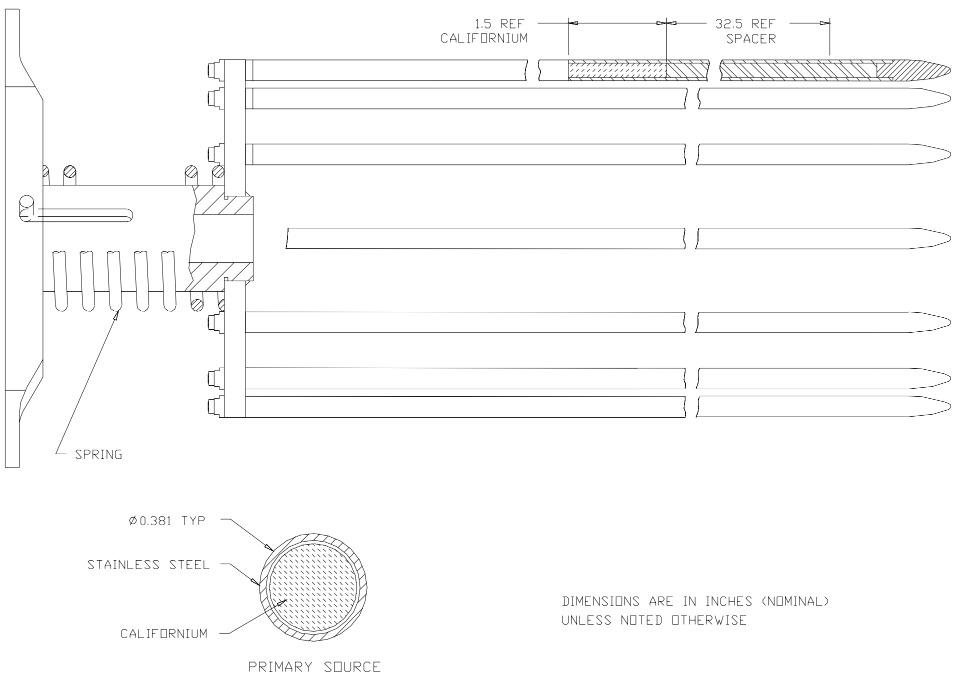


Figure 4.2-14

Primary Source Assembly

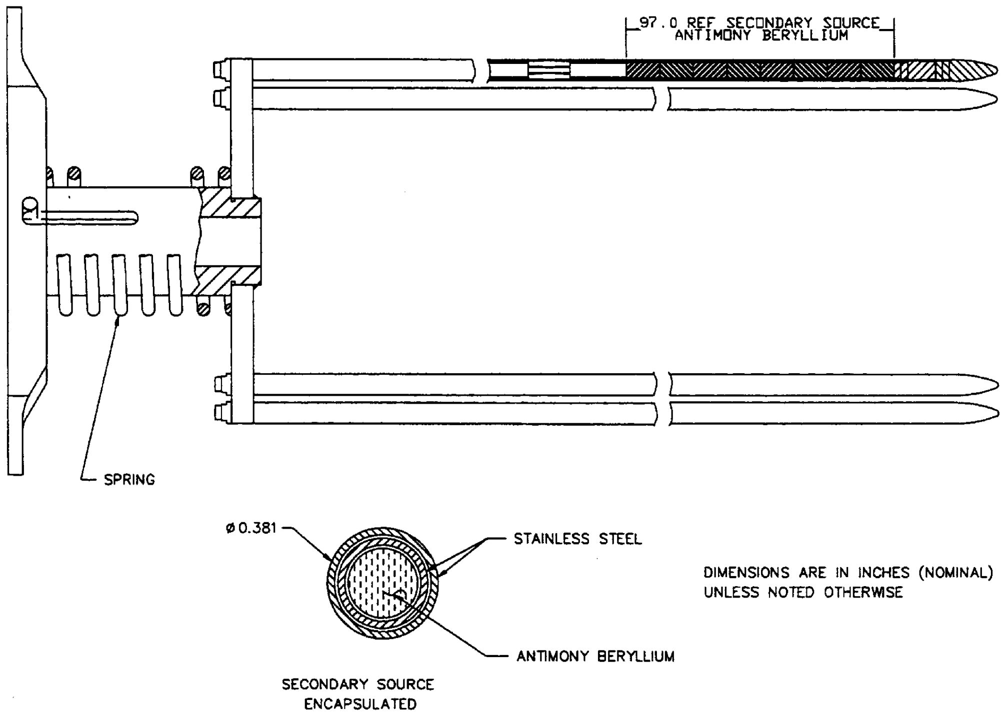


Figure 4.2-15

Secondary Source Assembly

4.3 Nuclear Design

4.3.1 Design Basis

This section describes the design bases and functional requirements used in the nuclear design of the fuel and reactivity control system and relates these design bases to the General Design Criteria (GDC). The design bases are the fundamental criteria that must be met using approved analytical techniques. [*Enhancements to these techniques may be made provided that the changes are founded by NRC approved methodologies as discussed in*]* WCAP-9272-P-A (Reference 1) and [*WCAP-12488-P-A (Reference 2).*]*

The plant conditions for design are divided into four categories:

- Condition I - Normal operation and operational transients
- Condition II - Events of moderate frequency
- Condition III - Infrequent incidents
- Condition IV - Limiting faults

The reactor is designed so that its components meet the following performance and safety criteria:

- In general, Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action.

- Condition II occurrences are accommodated with, at most, a shutdown of the reactor with the plant capable of returning to operation after corrective action.

- Fuel damage, that is, breach of fuel rod clad pressure boundary, is not expected during Condition I and Condition II occurrences. A very small amount of fuel damage may occur. This is within the capability of the chemical and volume control system (CVS) and is consistent with the plant design basis.

- Condition III occurrences do not cause more than a small fraction of the fuel elements in the reactor to be damaged, although sufficient fuel element damage might occur to preclude immediate resumption of operation.

- The release of radioactive material due to Condition III occurrences is not sufficient to interrupt or restrict public use of those areas beyond the exclusion area boundary.

- A Condition III occurrence does not by itself generate a Condition IV occurrence or result in a consequential loss of function of the reactor coolant or reactor containment barriers.

- Condition IV faults do not cause a release of radioactive material that results in exceeding the limits of 10 CFR 100. Condition IV occurrences are faults that are not expected to occur but are defined as limiting faults which are included in the design.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

The core design power distribution limits related to fuel integrity are met for Condition I occurrences through conservative design and are maintained by the action of the control system.

The requirements for Condition II occurrences are met by providing an adequate protection system which monitors reactor parameters.

The control and protection systems are described in Chapter 7.

The consequences of Condition II, III, and IV occurrences are described in Chapter 15.

4.3.1.1 Fuel Burnup

4.3.1.1.1 Basis

A limitation on initial installed excess reactivity or average discharge burnup is not required other than as is quantified in terms of other design bases, such as overall negative power reactivity feedback discussed below. [*The NRC has approved, in WCAP-12488-P-A (Reference 2), maximum fuel rod average burnup of 60,000 MWD/MTU. Extended burnup to 62,000 MWD/MTU has been established in Reference 61.*]*

4.3.1.1.2 Discussion

Fuel burnup is a measure of fuel depletion which represents the integrated energy output of the fuel in megawatt-days per metric ton of uranium (MWD/MTU) and is a useful means for quantifying fuel exposure criteria.

The core design lifetime, or design discharge burnup, is achieved by installing sufficient initial excess reactivity in each fuel region and by following a fuel replacement program (such as that described in subsection 4.3.2) that meets the safety-related criteria in each cycle of operation.

Initial excess reactivity installed in the fuel, although not a design basis, must be sufficient to maintain core criticality at full-power operating conditions throughout cycle life with equilibrium xenon, samarium, and other fission products present. Burnable absorbers and/or chemical shim are used to compensate for the excess reactivity. The end of design cycle life is defined to occur when the chemical shim concentration is essentially zero with control rods present to the degree necessary for operational requirements. In terms of soluble boron concentration, this corresponds to approximately 10 ppm with the control and gray rods essentially withdrawn.

4.3.1.2 Negative Reactivity Feedbacks (Reactivity Coefficients)

4.3.1.2.1 Basis

For the initial fuel cycle, the fuel temperature coefficient will be negative, and the moderator temperature coefficient of reactivity will be negative for power operating conditions, thereby providing negative reactivity feedback characteristics. The design basis meets General Design Criterion 11.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

4.3.1.2.2 Discussion

When compensation for a rapid increase in reactivity is considered, there are two major effects. These are the resonance absorption (Doppler) effects associated with changing fuel temperature and the neutron spectrum and reactor composition change effects resulting from changing moderator density. These basic physics characteristics are often identified by reactivity coefficients. The use of slightly enriched uranium results in a Doppler coefficient of reactivity that is negative. This coefficient provides the most rapid reactivity compensation. The initial core is also designed to have an overall negative moderator temperature coefficient of reactivity during power operation so that average coolant temperature changes or void content provides another, slower compensatory effect. For some core designs, if the compensation for excess reactivity is provided only by chemical shim, the moderator temperature coefficient could become positive. Nominal power operation is permitted only in a range of overall negative moderator temperature coefficient. The negative moderator temperature coefficient can be achieved through the use of discrete burnable absorbers (BAs) and/or integral fuel burnable absorbers and/or control rods by limiting the reactivity controlled by soluble boron.

Burnable absorber content (quantity and distribution) is not stated as a design basis. However, for some reloads, the use of burnable absorbers may be necessary for power distribution control and/or to achieve an acceptable moderator temperature coefficient throughout core life. The required burnable absorber loading is that which is required to meet design criteria.

4.3.1.3 Control of Power Distribution

4.3.1.3.1 Basis

The nuclear design basis is that, with at least a 95 percent confidence level:

- The fuel will not operate with a power distribution that would result in exceeding the departure from nucleate boiling (DNB) design basis (i.e., the departure from nucleate boiling ratio (DNBR) shall be greater than the design limit departure from nucleate boiling ratio as discussed in subsection 4.4.1) under Condition I and II occurrences, including the maximum overpower condition.

- Under abnormal conditions, including the maximum overpower condition, the peak linear heat rate (PLHR) will not cause fuel melting, as defined in subsection 4.4.1.2.

- Fuel management will be such as to produce values of fuel rod power and burnup consistent with the assumptions in the fuel rod mechanical integrity analysis of Section 4.2.

- The fuel will not be operated at Peak Linear Heat Rate (PLHR) values greater than those found to be acceptable within the body of the safety analysis under normal operating conditions, including an allowance of one percent for calorimetric error.

The above basis meets General Design Criterion 10.

4.3.1.3.2 Discussion

Calculation of extreme power shapes which affect fuel design limits are performed with proven methods. The conditions under which limiting power shapes are assumed to occur are chosen conservatively with regard to any permissible operating state. Even though there is close agreement between calculated peak power and measurements, a nuclear uncertainty is applied (subsection 4.3.2.2.1) to calculated power distribution. Such margins are provided both for the analysis for normal operating states and for anticipated transients.

4.3.1.4 Maximum Controlled Reactivity Insertion Rate

4.3.1.4.1 Basis

The maximum reactivity insertion rate due to withdrawal of rod cluster control assemblies (RCCAs) or gray rod cluster assemblies (GRCAs) or by boron dilution is limited by plant design, hardware, and basic physics. During normal power operation, the maximum controlled reactivity insertion rate is limited. The maximum reactivity change rate for accidental withdrawal of two control banks is set such that PLHR and the departure from nucleate boiling ratio limitations are not challenged. This satisfies General Design Criterion 25.

The maximum reactivity worth of control rods and the maximum rates of reactivity insertion employing control rods are limited to preclude rupture of the coolant pressure boundary or disruption of the core internals to a degree which would impair core cooling capacity due to a rod withdrawal or an ejection accident. (See Chapter 15).

Following any Condition IV occurrence, such as rod ejection or steam line break, the reactor can be brought to the shutdown condition, and the core maintains acceptable heat transfer geometry. This satisfies General Design Criterion 28.

4.3.1.4.2 Discussion

Reactivity addition associated with an accidental withdrawal of a control bank (or banks) is limited by the maximum rod speed (or travel rate) and by the worth of the bank(s). For this reactor, the maximum control and gray rod speed is 45 inches per minute.

The reactivity change rates are conservatively calculated, assuming unfavorable axial power and xenon distributions. The typical peak xenon burnout rate is significantly lower than the maximum reactivity addition rate for normal operation and for accidental withdrawal of two banks.

4.3.1.5 Shutdown Margins

4.3.1.5.1 Basis

Minimum shutdown margin as specified in the technical specifications is required in all operating modes.

In analyses involving reactor trip, the single, highest worth rod cluster control assembly is postulated to remain untripped in its full-out position (stuck rod criterion). This satisfies General Design Criterion 26.

4.3.1.5.2 Discussion

Two independent reactivity control systems are provided: control rods and soluble boron in the coolant. The control rods provide reactivity changes which compensate for the reactivity effects of the fuel and water density changes accompanying power level changes over the range from full load to no load. The control rods provide the minimum shutdown margin under Condition I occurrences and are capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits (very small number of rod failures), assuming that the highest worth control rod is stuck out upon trip.

The boron system can compensate for xenon burnout reactivity changes and maintain the reactor in the cold shutdown condition. Thus, backup and emergency shutdown provisions are provided by mechanical and chemical shim control systems which satisfy General Design Criterion 26. Reactivity changes due to fuel depletion are accommodated with the boron system.

4.3.1.5.3 Basis

When fuel assemblies are in the pressure vessel and the vessel head is not in place, k_{eff} will be maintained at or below 0.95 with control rods and soluble boron. Further, the fuel will be maintained sufficiently subcritical that removal of the rod cluster control assemblies will not result in criticality.

4.3.1.5.4 Discussion

ANSI N18.2 (Reference 3) specifies a k_{eff} not to exceed 0.95 in spent fuel storage racks and transfer equipment flooded with pure water and a k_{eff} not to exceed 0.98 in normally dry new fuel storage racks, assuming optimum moderation. No criterion is given for the refueling operation. However, a five percent margin, which is consistent with spent fuel storage and transfer and the new fuel storage, is adequate for the controlled and continuously monitored operations involved.

The boron concentration required to meet the refueling shutdown criteria is specified in the technical specifications. Verification that these shutdown criteria are met, including uncertainties, is achieved using standard design methods. The subcriticality of the core is continuously monitored as described in the technical specifications.

4.3.1.6 Stability

4.3.1.6.1 Basis

The core will be inherently stable to power oscillations at the fundamental mode. This satisfies General Design Criterion 12.

Spatial power oscillations within the core with a constant core power output, should they occur, can be reliably and readily detected and suppressed.

4.3.1.6.2 Discussion

Oscillations of the total power output of the core, from whatever cause, are readily detected by the loop temperature sensors and by the nuclear instrumentation. The core is protected by these systems; a reactor trip occurs if power increases unacceptably, thereby preserving the design margins to fuel design limits. The combined stability of the turbine, steam generator and the reactor power control systems are such that total core power oscillations are not normally possible. The redundancy of the protection circuits results in a low probability of exceeding design power levels.

The core is designed so that diametral and azimuthal oscillations due to spatial xenon effects are self-damping; no operator action or control action is required to suppress them. The stability to diametral oscillations is so great that this excitation is highly improbable. Convergent azimuthal oscillations can be excited by prohibited motion of individual control rods.

Indications of power distribution anomalies are continuously available from an online core monitoring system. The online monitoring system processes information provided by the fixed in-core detectors, in-core thermocouples, and loop temperature measurements. Radial power distributions are therefore continuously monitored, thus power oscillations are readily observable and alarmed. The ex-core long ion chambers also provide surveillance and alarms of anomalous power distributions. In proposed core designs, these horizontal plane oscillations are self-damping by virtue of reactivity feedback effects inherent to the basic core physics.

Axial xenon spatial power oscillations may occur during core life, especially late in the cycle. The online core monitoring system provides continuous surveillance of the axial power distributions. The control rod system provides both manual and automatic control systems for controlling the axial power distributions.

Confidence that fuel design limits are not exceeded is provided by reactor protection system overpower ΔT (OPΔT) and overtemperature ΔT (OTΔT) trip functions, which use the loop temperature sensors, pressurizer pressure indication, and measured axial offset as an input. Detection and suppression of xenon oscillations are discussed in subsection 4.3.2.7.

4.3.1.7 Anticipated Transients Without Scram (ATWS)

The AP1000 diverse reactor trip actuation system is independent of the reactor trip breakers used by the protection monitoring system. The diverse reactor trip reduces the probability and consequences of a postulated ATWS. The effects of anticipated transients with failure to trip are not considered in the design bases of the plant. Analysis has shown that the likelihood of such a hypothetical event is negligibly small. Furthermore, analysis of the consequences of a hypothetical failure to trip following anticipated transients has shown that no significant core damage would result, system peak pressures should be limited to acceptable values, and no failure of the reactor coolant system would result. (See WCAP-8330, Reference 5). The process used to evaluate the ATWS risk in compliance with 10 CFR 50.62 is described in Section 15.8 of this DCD.

4.3.2 Description

4.3.2.1 Nuclear Design Description

The reactor core consists of a specified number of fuel rods held in bundles by spacer grids and top and bottom fittings. The fuel rods are fabricated from cylindrical tubes made of zirconium based alloy(s) containing uranium dioxide fuel pellets. The bundles, known as fuel assemblies, are arranged in a pattern which approximates a right circular cylinder.

Each fuel assembly contains a 17 x 17 rod array composed nominally of 264 fuel rods, 24 rod cluster control thimbles, and an in-core instrumentation thimble. Figure 4.2-1 shows a cross-sectional view of a 17 x 17 fuel assembly and the related rod cluster control guide thimble locations. Detailed descriptions of the AP1000 fuel assembly design features are given in Section 4.2.

For initial core loading, the fuel rods within a given assembly have the same uranium enrichment in both the radial and axial planes. Fuel assemblies of three different enrichments are used in the initial core loading to establish a favorable radial power distribution. Figure 4.3-1 shows the fuel loading pattern used in the initial cycle. Two regions consisting of the two lower enrichments are interspersed to form a checkerboard pattern in the central portion of the core. The third region is arranged around the periphery of the core and contains the highest enrichment. The enrichments for the initial cycle are shown in Table 4.3-1. Axial blankets consisting of fuel pellets of reduced enrichment placed at the ends of the enriched pellet stack have been considered and may be used in reload cycles. Axial blankets are included in the design basis to reduce neutron leakage and to improve fuel utilization.

Reload core loading patterns can employ various fuel management techniques including “low-leakage” designs where the feed fuel is interspersed checkerboard-style in the core interior and depleted fuel is placed on the periphery. Reload core designs, as well as the initial cycle design, are anticipated to operate approximately 18 months between refueling, accumulating a cycle burnup of approximately 21,000 MWD/MTU. The exact reloading pattern, the initial and final positions of assemblies, and the number of fresh assemblies and their placement are dependent on the energy requirement for the reload cycle and burnup and power histories of the previous cycles.

The core average enrichment is determined by the amount of fissionable material required to provide the desired energy requirements. The physics of the burnout process is such that operation of the reactor depletes the amount of fuel available due to the absorption of neutrons by the U-235 atoms and their subsequent fission. In addition, the fission process results in the formation of fission products, some of which readily absorb neutrons. These effects, the depletion and the buildup of fission products, are partially offset by the buildup of plutonium shown in Figure 4.3-2 for a typical 17 x 17 fuel assembly, which occurs due to the parasitic absorption of neutrons in U-238. Therefore, at the beginning of any cycle a reactivity reserve equal to the depletion of the fissionable fuel and the buildup of fission product poisons less the buildup of fissile fuel over the specified cycle life is built into the reactor. This excess reactivity is controlled by removable neutron-absorbing material in the form of boron dissolved in the primary coolant, control rod insertion, burnable absorber rods, and/or integral fuel burnable absorbers (IFBA). The stack length

of the burnable absorber rods and/or integral absorber bearing fuel may vary for different core designs, with the optimum length determined on a design specific basis. Figure 4.3-3 is a plot of the initial core soluble boron concentration versus core depletion.

The concentration of the soluble neutron absorber is varied to compensate for reactivity changes due to fuel burnup, fission product poisoning including xenon and samarium, burnable absorber depletion, and the cold-to-operating moderator temperature change. Throughout the operating range, the CVS is designed to provide changes in reactor coolant system (RCS) boron concentration to compensate for the reactivity effects of fuel depletion, peak xenon burnout and decay, and cold shutdown boration requirements.

Burnable absorbers are strategically located to provide a favorable radial power distribution and provide for negative reactivity feedback. Figures 4.3-4a and 4.3-4b show the burnable absorber distributions within a fuel assembly for the several patterns used in a 17 x 17 array. The initial core burnable absorber loading pattern is shown in Figure 4.3-5.

Tables 4.3-1 through 4.3-3 contain summaries of reactor core design parameters including reactivity coefficients, delayed neutron fraction, and neutron lifetimes. Sufficient information is included to permit an independent calculation of the nuclear performance characteristics of the core.

4.3.2.2 Power Distribution

The accuracy of power distribution calculations has been confirmed through approximately 1000 flux maps under conditions very similar to those expected. Details of this confirmation are given in WCAP-7308-L-P-A (Reference 7) and in subsection 4.3.2.2.7.

4.3.2.2.1 Definitions

Relative power distributions within the reactor are quantified in terms of hot channel factors. These hot channel factors are normalized ratios of maximal absolute power generation rates and are a measure of the peak pellet power within the reactor core relative to the average pellet (F_Q) and the energy produced in a coolant channel relative to the core average channel ($F_{\Delta H}$). Absolute power generation rates are expressed in terms of quantities related to the nuclear or thermal design; more specifically, volumetric power density (q_{vol}) is the thermal power produced per unit volume of the core (kW/l).

Linear heat rate (LHR) is the thermal power produced per unit length of active fuel (kW/ft). Since fuel assembly geometry is standardized, LHR is the unit of absolute power density most commonly used. For practical purposes, LHR differs from q_{vol} by a constant factor which includes geometry effects and the heat flux deposition fraction. The peak linear heat rate (PLHR) is defined as the maximum linear heat rate occurring throughout the reactor. PLHR directly impacts fuel temperatures and decay power levels thus being a significant safety analysis parameter.

Average linear heat rate (ALHR) is the total thermal power produced in the fuel rods expressed as heat flux divided by the total active fuel length of the rods in the core.

Local heat flux is the heat flux at the surface of the cladding (Btu/hr-ft^2). For nominal rod parameters, this differs from linear heat rate by a constant factor.

Rod power is the total power generated in one rod (kW).

Average rod power is the total thermal power produced in the fuel rods divided by the number of fuel rods (assuming the rods have equal length).

The hot channel factors used in the discussion of power distributions in this section are defined as follows:

F_Q, **heat flux hot channel factor**, is defined as the maximum local heat flux on the surface of a fuel rod divided by the average fuel rod heat flux, allowing for manufacturing tolerances on fuel pellets and rods.

F^N_Q, **nuclear heat flux hot channel factor**, is defined as the maximum local fuel rod linear heat rate divided by the average fuel rod linear heat rate, assuming nominal fuel pellet and rod parameters.

F^E_Q, **engineering heat flux hot channel factor**, is the allowance on heat flux required for manufacturing tolerances. The engineering factor allows for local variations in enrichment, pellet density and diameter, burnable absorber content, surface area of the fuel rod, and eccentricity of the gap between pellet and clad. Combined statistically, the net effect is a factor of 1.03 to be applied to the fuel rod surface heat flux.

$F^N_{\Delta H}$, **nuclear enthalpy rise hot channel factor**, is defined as the ratio of the maximum integrated rod power within the core to the average rod power.

Manufacturing tolerances, hot channel power distribution, and surrounding channel power distributions are treated explicitly in the calculation of the departure from nucleate boiling ratio described in Section 4.4.

It is convenient for the purposes of discussion to define subfactors of F_Q. However, design limits are set in terms of the total peaking factor.

$$F_Q = \text{total peaking factor or heat flux hot channel factor} = \frac{\text{PLHR}}{\text{ALHR}}$$

Without densification effects:

$$F_Q = F^N_Q \times F^E_Q = F^N_{XY} \times F^N_Z \times F^N_u \times F^E_Q$$

where F^N_Q and F^E_Q are defined above and:

F^N_U = factor for calculational uncertainty, assumed to be 1.05.

F^N_{XY} = ratio of peak power density to average power density in the horizontal plane of peak local power.

F^N_Z = ratio of the power per unit core height in the horizontal plane of peak local power to the average value of power per unit core height. If the plane of peak local power coincides with the plane of maximum power per unit core height, then F^N_Z is the core average axial peaking factor.

4.3.2.2.2 Radial Power Distributions

The power shape in horizontal sections of the core at full power is a function of the fuel assembly and burnable absorber loading patterns, the control rod pattern, and the fuel burnup distribution. Thus, at any time in the cycle, a horizontal section of the core can be characterized as unrodded or with control rods. These two situations combined with burnup effects determine the radial power shapes which can exist in the core at full power. Typical first cycle values of $F^N_{\Delta H}$, the nuclear enthalpy rise hot channel factors from beginning of life (BOL) to end of life (EOL) are given in Table 4.3-2. The effects on radial power shapes of power level, xenon, samarium, and moderator density effects are also considered, but these are quite small. The effect of nonuniform flow distribution is negligible. While radial power distributions in various planes of the core are often illustrated, since the moderator density is directly proportional to enthalpy, the core radial enthalpy rise distribution, as determined by the integral of power up each channel, is of greater interest. Figures 4.3-6 through 4.3-11 show typical normalized power density distributions for one-eighth of the core for representative operating conditions. These conditions are as follows:

- Hot full power (HFP) near beginning of life, unrodded, no xenon
- Hot full power near beginning of life, unrodded, equilibrium xenon
- Hot full power near beginning of life, gray bank M0 in, equilibrium xenon
- Hot full power near middle of life (MOL), unrodded equilibrium xenon
- Hot full power near end of life, unrodded, equilibrium xenon
- Hot full power near end of life, gray bank M0 in, equilibrium xenon

Since the position of the hot channel varies from time to time, a single-reference radial design power distribution is selected for departure from nucleate boiling calculations. This reference power distribution is chosen conservatively to concentrate power in one area of the core, minimizing the benefits of flow redistribution. Assembly powers are normalized to core average power. The radial power distribution within a fuel rod and its variation with burnup as utilized in thermal calculations and fuel rod design are discussed in Section 4.4.

4.3.2.2.3 Assembly Power Distributions

For the purpose of illustration, typical rodwise power distributions from the beginning of life and end of life conditions corresponding to Figures 4.3-7 and 4.3-10, respectively, are given for the same assembly in Figures 4.3-12 and 4.3-13, respectively.

Since the detailed power distribution surrounding the hot channel varies from time to time, a conservatively flat radial assembly power distribution is assumed in the departure from nucleate boiling analysis, described in Section 4.4, with the rod of maximum integrated power artificially raised to the design value of $F^N_{\Delta H}$. Care is taken in the nuclear design of the fuel cycles and operating conditions to confirm that a flatter assembly power distribution does not occur with limiting values of $F^N_{\Delta H}$.

4.3.2.2.4 Axial Power Distributions

The distribution of power in the axial or vertical direction is largely under the control of the operator through either the manual operation of the control rods or the automatic motion of control rods in conjunction with manual operation of the chemical and volume control system. The automated mode of operation is referred to as mechanical shim (MSHIM) and is discussed in subsection 4.3.2.4.16. The rod control system automatically modulates the insertion of the axial offset (AO) control bank controlling the axial power distribution simultaneous with the MSHIM gray and control rod banks to maintain programmed coolant temperature. Operation of the chemical and volume control system is initiated manually by the operator to compensate for fuel burnup and maintain the desired MSHIM bank insertion. Nuclear effects which cause variations in the axial power shape include moderator density, Doppler effect on resonance absorption, spatial distribution of xenon, burnup, and axial distribution of fuel enrichment and burnable absorber. Automatically controlled variations in total power output and rod motion are also important in determining the axial power shape at any time.

The online core monitoring system provides the operator with detailed power distribution information in both the radial and axial sense on demand using signals from the fixed in-core detectors. Signals are also available to the operator from the ex-core ion chambers, which are long ion chambers outside the reactor vessel running parallel to the axis of the core. Separate signals are taken from the each ion chamber. The ion chamber signals are processed and calibrated against in-core measurements such that an indication of the power in the top of the core less the power in the bottom of the core is derived. The calibrated difference in power between the core top and bottom halves, called the flux difference (ΔI), is derived for each of the four channels of ex-core detectors and is displayed on the control panel. The principal use of the flux difference is to provide the shape penalty function to the OTΔT DNB protection and the OPΔT overpower protection.

4.3.2.2.5 Local Power Peaking

Fuel densification occurred early in the evolution of pressurized water reactor fuel manufacture under irradiation in several operating reactors. This caused the fuel pellets to shrink both axially and radially. The pellet shrinkage combined with random hang-up of fuel pellets can result in gaps in the fuel column when the pellets below the hung-up pellet settle in the fuel rod. The gaps vary

in length and location in the fuel rod. Because of decreased neutron absorption in the vicinity of the gap, power peaking occurs in the adjacent fuel rods, resulting in an increased power peaking factor. A quantitative measure of this local peaking is given by the power spike factor S(Z), where Z is the axial location in the core. The power spike factor S(z) is discussed in References 8, 9, and 10.

Modern PWR fuel manufacturing practices have essentially eliminated significant fuel densification impacts on reactor design and operation. It has since been concluded and accepted that a densification power spike factor of 1.0 is appropriate for Westinghouse fuel as described in WCAP-13589-A (Reference 59).

4.3.2.2.6 Limiting Power Distributions

According to the ANSI classification of plant conditions (Chapter 15), Condition I occurrences are those expected frequently or regularly in the course of power operation, maintenance, or maneuvering of the plant. As such, Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action. Condition I occurrences are considered from the point of view of affecting the consequences of fault conditions (Conditions II, III, and IV). Analysis of each fault condition described is based on a conservative set of corresponding initial conditions.

The list of steady-state and shutdown conditions, permissible deviations, and operational transients is given in Chapter 15. Implicit in the definition of normal operation is proper and timely action by the reactor operator; that is, the operator follows recommended operating procedures for maintaining appropriate power distributions and takes any necessary remedial actions when alerted to do so by the plant instrumentation.

The online monitoring system evaluates the consequences of limiting power distributions based upon the conditions prevalent in the reactor at the current time. Operating space evaluations performed by the online monitoring system include the most limiting power distributions that can be generated by inappropriate operator or control system actions given the current core power level, xenon distribution, MSHIM or AO bank insertion and core burnup. Thus, as stated, the worst or limiting power distribution which can occur during normal operation is considered as the starting point for analysis of Conditions II, III, and IV occurrences.

Improper procedural actions or errors by the operator are assumed in the design as occurrences of moderate frequency (Condition II). Some of the consequences which might result are discussed in Chapter 15. Therefore, the limiting power shapes which result from such Condition II occurrences are those power distributions which deviate from the normal operating condition within the allowable operating space as defined in the core operating limits; e.g., due to lack of proper action by the operator during a xenon transient following a change in power level brought about by control rod motion. Power distributions which fall in this category are used for determination of the reactor protection system setpoints to maintain margin to overpower or departure from nucleate boiling limits.

The means for maintaining power distributions within the required absolute power generation limits are described in the technical specifications. The online core monitoring system provides

the operator with the current allowable operating space, detailed current power distribution information, thermal margin assessment and operational recommendations to manage and maintain required thermal margins. As such, the online monitoring system provides the primary means of managing and maintaining required operating thermal margins during normal operation.

In the unlikely event that the online monitoring system is out of service, power distribution controls based on bounding, precalculated analysis are also provided to the operator such that the online monitoring system is not a required element of reactor operation. A discussion of precalculated power distribution control in Westinghouse pressurized water reactors (PWRs) is included in WCAP-7811 (Reference 11). Detailed background information on the design constraints on local power density in a Westinghouse PWR, on the defined operating procedures, and on the measures taken to preclude exceeding design limits is presented in the Westinghouse topical report on power distribution control and load following procedures WCAP-8385 (Reference 12). The following paragraphs summarize these reports and describe the calculations used to establish the upper bound on peaking factors.

The calculations used to establish the upper bound on peaking factors, F_Q and $F_{\Delta H}^N$, include the nuclear effects which influence the radial and axial power distributions throughout core life for various modes of operation, including load follow, reduced power operation, and axial xenon transients.

Power distributions are calculated for the full-power condition. Fuel and moderator temperature feedback effects are included within these calculations in each spatial dimension. The steady-state nuclear design calculations are done for normal flow with the same mass flow in each channel and flow redistribution effects neglected. The effect of flow redistribution is calculated explicitly where it is important in the departure from nucleate boiling analysis of accidents. The effect of xenon on radial power distribution is small (compare Figures 4.3-6 and 4.3-7) but is included as part of the normal design process.

The core axial profile can experience significant changes, which can occur rapidly as a result of rod motion and load changes and more slowly due to xenon distribution. For the study of points of closest approach to thermal margin limits, several thousand cases are examined. Since the properties of the nuclear design dictate what axial shapes can occur, boundaries on the limits of interest can be set in terms of the parameters which are readily observed on the plant. Specifically, the nuclear design parameters significant to the axial power distribution analysis are as follows:

- Core power level
- Core height
- Coolant temperature and flow
- Coolant temperature program as a function of reactor power
- Fuel cycle lifetimes
- Rod bank worth
- Rod bank overlaps

Normal operation of the plant assumes compliance with the following conditions:

- Control rods in a single bank move together with no individual rod insertion differing from the bank demand position by more than the number of steps identified in the technical specifications.
- Control banks are sequenced with overlapping banks.
- The control bank insertion limits are not violated.
- Axial power distribution control procedures, which are given in terms of flux difference control and control bank position, are observed.

The axial power distribution procedures referred to above are part of the required operating procedures followed in normal operation with the online monitoring system out of service. In service, the online core monitoring system provides continuous indication of power distribution, shutdown margin, and margin to design limits.

Limits placed on the axial flux difference are designed so that the heat flux hot channel factor F_Q is maintained within acceptable limits. The relaxed axial offset control (RAOC) procedures described in WCAP-10216-P-A (Reference 13) were developed to provide wide control band widths and consequently, more operating flexibility. These wide operating limits, particularly at lower power levels, increase plant availability by allowing quicker plant startup and increased maneuvering flexibility without trip or reportable occurrences. This procedure has been modified to accommodate AP1000 MSHIM operation. It is applied to analysis of axial power distributions under MSHIM control for the purpose of defining the allowed normal operating space such that Condition I thermal margin limits are maintained and Condition II occurrences are adequately protected by the reactor protection system when the online monitoring system is out of service.

The purpose of this analysis is to find the widest permissible ΔI versus power operating space by analyzing a wide range of achievable xenon distributions, MSHIM/AO bank insertion, and power level.

The bounding analyses performed off line in anticipation of the online monitoring system being out of service is similar to that based on the relaxed axial offset control analysis, which uses a xenon reconstruction model described in WCAP-10216-P-A (Reference 13). This is a practical method which is used to define the power operating space allowed with AP1000 MSHIM operation. Each resulting power shape is analyzed to determine if loss-of-coolant accident constraints are met or exceeded.

The online monitoring system evaluates the effects of radial xenon distribution changes due to operational parameter changes continuously and therefore eliminates the need for overly conservative bounding evaluations when the online monitoring system is available. A detailed discussion of this effect may be found in WCAP-8385 (Reference 12). The calculated values have been increased by a factor of 1.05 for method uncertainty and a factor of 1.03 for the engineering factor F^E_Q.

The envelope drawn in Figure 4.3-14 represents an upper bound envelope on local power density versus elevation in the core. This envelope is a conservative representation of the bounding values of local power density.

Finally, as previously discussed, this upper bound envelope is based on procedures of load follow which require operation within specified axial flux difference limits. These procedures are detailed in the technical specifications for the case of the online monitoring system not being available, and are followed by relying only upon ex-core surveillance supplemented by the normal monthly full core map requirement and by computer-based alarms on deviation from the allowed flux difference band. The online monitoring system measures the core condition continuously and evaluates the thermal margin condition directly in terms of peak linear heat rate and margin to departure from nucleate boiling limitations directly.

Allowing for fuel densification effects, the average linear power at 3400 MW is 5.72 kW/ft. From Figure 4.3-14, the conservative upper bound value of normalized local power density, including uncertainty allowances, is 2.60 corresponding to a peak linear heat rate of 15.0 kW/ft at each core elevation at 101 percent power.

To determine reactor protection system setpoints with respect to power distributions, three categories of events are considered: rod control equipment malfunctions and operator errors of commission or omission. In evaluating these three categories of events, the core is assumed to be operating within the four constraints described above.

The first category comprises uncontrolled rod withdrawal (with rods moving in the normal bank sequence) for both AO and MSHIM banks. Also included are motions of the AO and MSHIM banks below their insertion limits, which could be caused, for example, by uncontrolled dilution or primary coolant cooldown. Power distributions are calculated throughout these occurrences, assuming short-term corrective action; that is, no transient xenon effects are considered to result from the malfunction. The event is assumed to occur from typical normal operating situations, which include normal xenon transients. It is further assumed in determining the power distributions that total core power level would be limited by reactor trip to below the overpower protection setpoint of nominally 118 percent rated thermal power. Since the study is to determine protection limits with respect to power and axial offset, no credit is taken for OTΔT or OPΔT trip setpoint reduction due to flux difference. The peak power density which can occur in such events, assuming reactor trip at or below 118 percent, is less than that required for fuel centerline melt, including uncertainties and densification effects.

The second category assumes that the operator mispositions the AO and/or MSHIM rod banks in violation of the insertion limits and creates short-term conditions not included in normal operating conditions.

The third category assumes that the operator fails to take action to correct a power distribution limit violation (such as boration/dilution transient) assuming automatic operation of the rod control system which will maintain constant reactor power.

For each of the above categories, the trip setpoints are designed so as not to exceed fuel centerline melt criteria as well as fuel mechanical design criteria.

The appropriate hot channel factors F_Q and $F_{\Delta H}^N$ for peak local power density and for DNB analysis at full power are based on analyses of possible operating power shapes and are addressed in the technical specifications.

The maximum allowable F_Q can be increased with decreasing power, as shown in the technical specifications. Increasing $F_{\Delta H}^N$ with decreasing power is permitted by the DNB protection setpoints and allows radial power shape changes with rod insertion to the insertion limits, as described in subsection 4.4.4.3. The allowance for increased $F_{\Delta H}^N$ permitted is addressed in the technical specifications.

This becomes a design basis criterion which is used for establishing acceptable control rod patterns and control bank sequencing. Likewise, fuel loading patterns for each cycle are selected with consideration of this design criterion. The worst values of $F_{\Delta H}^N$ for possible rod configurations occurring in normal operation are used in verifying that this criterion is met. The worst values generally occur when the rods are assumed to be at their insertion limits. Operation with rod positions above the allowed rod insertion limits provides increased margin to the $F_{\Delta H}^N$ criterion. As discussed in Section 3.2 of WCAP-7912-P-A (Reference 14), it has been determined that the technical specifications limits are met, provided the above conditions are observed. These limits are taken as input to the thermal-hydraulic design basis, as described in subsection 4.4.4.3.1.

When a situation is possible in normal operation which could result in local power densities in excess of those assumed as the precondition for a subsequent hypothetical accident, but which would not itself cause fuel failure, administrative controls and alarms are provided for returning the core to a safe condition. These alarms are described in Chapter 7.

The independence of the various individual uncertainties constituting the uncertainty factor on F_Q enables the uncertainty (F^U_Q) to be calculated by statistically combining the individual uncertainties on the limiting rod. The standard deviation of the resultant distribution of F^U_Q is determined by taking the square root of the sum of the variances of each of the contributing distributions WCAP-7308-L-P-A (Reference 7). The values for F^E_Q and F^N_U are 1.03 and 1.05, respectively. The value for the rod bow factor, F^B_Q, is 1.056, which accounts for the maximum F_Q penalty as a function of burnup due to rod bow effects.

4.3.2.2.7 Experimental Verification of Power Distribution Analysis

This subject is discussed in WCAP-7308-L-P-A (Reference 7) and WCAP-12472-P-A (Reference 4). A summary of these reports and the extension to include the fixed in-core instrumentation system is given below. Power distribution related measurements are incorporated into the evaluation of calculated power distribution information using the in-core instrumentation processing algorithms contained within the online monitoring system. The processing algorithms contained within the online monitoring system are functionally identical to those historically used for the evaluation of power distribution measurements in Westinghouse PWRs. Advances in

technology allow a complete functional integration of reaction rate measurement algorithms and the expected reaction rate predictive capability within the same software package. The predictive software integrated within the online monitoring system supplies accurate, detailed information of current reactor conditions. The historical algorithms are described in detail in WCAP-8498 (Reference 15).

The measured versus calculational comparison is performed continuously by the online monitoring system throughout the core life. The online monitoring system operability requirements are specified in the technical specifications.

In a measurement of the reactor power distribution and the associated thermal margin limiting parameters, with the in-core instrumentation system described in subsections 7.7.1 and 4.4.6, the following uncertainties must be considered:

A. Reproducibility of the measured signal

B. Errors in the calculated relationship between detector current and local power generation within the fuel bundle

C. Errors in the detector current associated with the depletion of the emitter material, manufacturing tolerances and measured detector depletion

D. Errors due to the inference of power generation some distance from the measurement thimble.

The appropriate allowance for category A has been accounted for through the imposition of strict manufacturing tolerances for the individual detectors. This approach is accepted industry practice and has been used in PWRs with fixed in-core instrumentation worldwide. Errors in category B above are quantified by calculation and evaluation of critical experiment data on arrays of rods with simulated guide thimbles, control rods, burnable absorbers, etc. These critical experiments provide the quantification of errors of categories A and D above. Errors in category C have been quantified through direct experimental measurement of the depletion characteristics of the detectors being used including the precision of the in-core instrumentation systems measurement of the current detector depletion. The description of the experimental measurement of detector depletion can be found in EPRI-NP-3814 (Reference 16).

WCAP-7308-L-P-A (Reference 7) describes critical experiments performed at the Westinghouse Reactor Evaluation Center and measurements taken on two Westinghouse plants with movable fission chamber in-core instrumentation systems. The measurement aspects of the movable fission chamber share the previous uncertainty categories less category C which is independent of the other sources of uncertainty. WCAP-7308-L-P-A (Reference 7) concludes that the uncertainty associated with peak linear heat rate (F_Q*P) is less than five percent at the 95 percent confidence level with only five percent of the measurements greater than the inferred value.

In comparing measured power distributions (or detector currents) with calculations for the same operating conditions, it is not possible to isolate the detector reproducibility. Thus, a comparison between measured and predicted power distributions includes some measurement error. Such a comparison is given in Figure 4.3-15 for one of the maps used in WCAP-7308-L-P-A (Reference 7). Since the first publication of WCAP-7308-L-P-A, hundreds of measurements have

been taken on reactors all over the world. These results confirm the adequacy of the five percent uncertainty allowance on the calculated peak linear heat rate (ALHR*F_Q*P).

A similar analysis for the uncertainty in hot rod integrated power $F_{\Delta H}$*P measurements results in an allowance of four percent at the equivalent of a 95 percent confidence level.

A measurement in the fourth cycle of a 157-assembly, 12-foot core is compared with a simplified one-dimensional core average axial calculation in Figure 4.3-16. This calculation does not give explicit representation to the fuel grids.

The accumulated data on power distributions in actual operation are basically of three types:

- Much of the data is obtained in steady-state operation at constant power in the normal operating configuration.
- Data with unusual values of axial offset are obtained as part of the ex-core detector calibration exercise performed monthly.
- Special tests have been performed in load follow and other transient xenon conditions which have yielded useful information on power distributions.

These data are presented in detail in WCAP-7912-P-A (Reference 14). Figure 4.3-17 contains a summary of measured values of F_Q as a function of axial offset for five plants from that report.

4.3.2.2.8 Testing

A series of physics tests are planned to be performed on the first core. These tests and the criteria for satisfactory results are described in Chapter 14. Since not all limiting situations can be created at beginning of life, the main purpose of the tests is to provide a check on the calculational methods used in the predictions for the conditions of the test. Tests performed at the beginning of each reload cycle are limited to verification of the selected safety-related parameters of the reload design.

4.3.2.2.9 Monitoring Instrumentation

The adequacy of instrument numbers, spatial deployment, required correlations between readings and peaking factors, calibration, and errors are described in WCAP-12472-P (Reference 4). The relevant conclusions are summarized in subsection 4.3.2.2.7 and subsection 4.4.6.

Provided the limitations given in subsection 4.3.2.2.6 on rod insertion and flux difference are observed, the in-core and ex-core detector systems in conjunction with the online core monitoring system provide adequate online monitoring of power distributions. Further details of specific limits on the observed rod positions and flux difference are given in the technical specifications, together with a discussion of their bases.

Limits for alarms and reactor trip are given in the technical specifications. Descriptions of the systems provided are given in Section 7.7.

4.3.2.3 Reactivity Coefficients

The kinetic characteristics of the reactor core determine the response of the core to changing plant conditions or to operator adjustments made during normal operation, as well as the core response during abnormal or accidental transients. These kinetic characteristics are quantified in reactivity coefficients. The reactivity coefficients reflect the changes in the neutron multiplication due to varying plant conditions, such as thermal power, moderator and fuel temperatures, coolant pressure, or void conditions, although the latter are relatively unimportant. Since reactivity coefficients change during the life of the core, ranges of coefficients are employed in transient analysis to determine the response of the plant throughout life. The results of such simulations and the reactivity coefficients used are presented in Chapter 15.

The reactivity coefficients are calculated with approved nuclear methods. The effect of radial and axial power distribution on core average reactivity coefficients is implicit in those calculations and is not significant under normal operating conditions. For example, a skewed xenon distribution which results in changing axial offset by five percent typically changes the moderator and Doppler temperature coefficients by less than 0.01 pcm/°F. An artificially skewed xenon distribution which results in changing the radial $F^N_{\Delta H}$ by three percent typically changes the moderator and Doppler temperature coefficients by less than 0.03 pcm/°F and 0.001 pcm/°F, respectively. The spatial effects are accentuated in some transient conditions, for example, in postulated rupture of the main steam line and rupture of a rod cluster control assembly mechanism housing described in subsections 15.1.5 and 15.4.8, and are included in these analyses.

The analytical methods and calculational models used in calculating the reactivity coefficients are given in subsection 4.3.3. These models have been confirmed through extensive qualification efforts performed for core and lattice designs.

Quantitative information for calculated reactivity coefficients including fuel-Doppler coefficient, moderator coefficients (density, temperature, pressure, and void), and power coefficient, is given in the following sections.

4.3.2.3.1 Fuel Temperature (Doppler) Coefficient

The fuel temperature (Doppler) coefficient is defined as the change in reactivity per degree change in effective fuel temperature and is primarily a measure of the Doppler broadening of U-238 and Pu-240 resonance absorption peaks. Doppler broadening of other isotopes is also considered, but their contribution to the Doppler effect is small. An increase in fuel temperature increases the effective resonance absorption cross sections of the fuel and produces a corresponding reduction in reactivity.

The fuel temperature coefficient is calculated using approved nuclear methods. Moderator temperature is held constant, and the power level is varied. Spatial variation of fuel temperature is taken into account by calculating the effective fuel temperature as a function of power density, as discussed in subsection 4.3.3.1.

A typical Doppler temperature coefficient is shown in Figure 4.3-18 as a function of the effective fuel temperature (at beginning of life and end of life conditions). The effective fuel temperature is

lower than the volume-averaged fuel temperature, since the neutron flux distribution is non-uniform through the pellet and gives preferential weight to the surface temperature. A typical Doppler-only contribution to the power coefficient, defined later, is shown in Figure 4.3-19 as a function of relative core power. The integral of the differential curve in Figure 4.3-19 is the Doppler contribution to the power defect and is shown in Figure 4.3-20 as a function of relative power. The Doppler temperature coefficient becomes more negative as a function of life as the Pu-240 content increases, thus increasing the Pu-240 resonance absorption. The upper and lower limits of Doppler coefficient used in accident analyses are given in Chapter 15.

4.3.2.3.2 Moderator Coefficients

The moderator coefficient is a measure of the change in reactivity due to a change in specific coolant parameters, such as density/temperature, pressure, or void. The coefficients obtained are moderator density/temperature, pressure, and void coefficients.

4.3.2.3.2.1 Moderator Density and Temperature Coefficients

The moderator temperature (density) coefficient is defined as the change in reactivity per degree change in the moderator temperature. Generally, the effects of the changes in moderator density and the temperature are considered together.

The soluble boron used in the reactor as a means of reactivity control also has an effect on the moderator density coefficient, since the soluble boron density and the water density are decreased when the coolant temperature rises. A decrease in the soluble boron density introduces a positive component in the moderator coefficient. If the concentration of soluble boron is large enough, the net value of the coefficient may be positive.

The initial core hot boron concentration is sufficiently low that the moderator temperature coefficient is negative at operating temperatures with the burnable absorber loading specified. Discrete or integral fuel burnable absorbers can be used in reload cores to confirm the moderator temperature coefficient is negative over the range of power operation. The effect of control rods is to make the moderator coefficient more negative, since the thermal neutron mean free path, and hence the volume affected by the control rods, increase with an increase in temperature.

With burnup, the moderator coefficient becomes more negative, primarily as a result of boric acid dilution, but also to a significant extent from the effects of the buildup of plutonium and fission products.

The moderator coefficient is calculated for a range of plant conditions by performing two group two- or three-dimensional calculations, in which the moderator temperature is varied by about ±5°F about each of the mean temperatures, resulting in density changes consistent with the temperature change. The moderator temperature coefficient is shown as a function of core temperature and boron concentration for the core in Figures 4.3-21 through 4.3-23. The temperature range covered is from cold, about 70°F, to about 550°F. The contribution due to Doppler coefficient (because of change in moderator temperature) has been subtracted from these results. Figure 4.3-24 shows the unrodded hot, full-power moderator temperature coefficient plotted as a function of burnup for the initial cycle. The temperature coefficient corresponds to the unrodded critical boron concentration present at hot full power operating conditions.

The moderator coefficients presented here are calculated to describe the core behavior in normal and accident situations when the moderator temperature changes can be considered to affect the entire core.

4.3.2.3.2.2 Moderator Pressure Coefficient

The moderator pressure coefficient relates the change in moderator density, resulting from a reactor coolant pressure change, to the corresponding effect on neutron production. This coefficient is of much less significance than the moderator temperature coefficient. A change of 50 psi in pressure has approximately the same effect on reactivity as a one half degree change in moderator temperature. This coefficient can be determined from the moderator temperature coefficient by relating change in pressure to the corresponding change in density. The typical moderator pressure coefficient may be negative over a portion of the moderator temperature range at beginning of life (BOL) (-0.004 pcm/psi) but is always positive at operating conditions and becomes more positive during life (+0.3 pcm/psi, at end of life).

4.3.2.3.2 Moderator Void Coefficient

The moderator void coefficient relates the change in neutron multiplication to the presence of voids in the moderator. In a PWR, this coefficient is not very significant because of the low void content in the coolant. The core void content is less than one-half of one percent and is due to local or statistical boiling. The typical void coefficient varies from 50 pcm/percent void at BOL and at low temperatures to minus 250 pcm/percent void at EOL and at operating temperatures. The void coefficient at operating temperature becomes more negative with fuel burnup.

4.3.2.3.3 Power Coefficient

The combined effect of moderator temperature and fuel temperature change as the core power level changes is called the total power coefficient and is expressed in terms of reactivity change per percent power change. Since a three-dimensional calculation is performed in determining total power coefficients and total power defects, the axial redistribution reactivity component described in subsection 4.3.2.4.3 is implicitly included. A typical power coefficient at beginning of life (BOL) and end of life (EOL) conditions is given in Figure 4.3-25.

The total power coefficient becomes more negative with burnup, reflecting the combined effect of moderator and fuel temperature coefficients with burnup. The power defect (integral reactivity effect) at BOL and EOL is given in Figure 4.3-26.

4.3.2.3.4 Comparison of Calculated and Experimental Reactivity Coefficients

Subsection 4.3.3 describes the comparison of calculated and experimental reactivity coefficients in detail.

Experimental evaluation of the reactivity coefficients will be performed during the physics startup tests described in Chapter 14.

4.3.2.3.5 Reactivity Coefficients Used in Transient Analysis

Table 4.3-2 gives the limiting values as well as the best-estimate values for the reactivity coefficients for the initial cycle. The limiting values are used as design limits in the transient analysis. The exact values of the coefficient used in the analysis depend on whether the transient of interest is examined at the BOL or EOL, whether the most negative or the most positive (least negative) coefficients are appropriate, and whether spatial non-uniformity must be considered in the analysis. Conservative values of coefficients, considering various aspects of analysis, are used in the transient analysis. This is described in Chapter 15.

The reactivity coefficients shown in Figures 4.3-18 through 4.3-26 are typical best-estimate values calculated for the initial cycle. Limiting values are chosen to encompass the best-estimate reactivity coefficients, including the uncertainties given in subsection 4.3.3.3 over appropriate operating conditions. The most positive, as well as the most negative, values are selected to form the design basis range used in the transient analysis. A direct comparison of the best-estimate and design limit values for the initial cycle is shown in Table 4.3-2. In many instances the most conservative combination of reactivity coefficients is used in the transient analysis even though the extreme coefficients assumed may not simultaneously occur at the conditions assumed in the analysis. The need for a reevaluation of any accident in a subsequent cycle is contingent upon whether the coefficients for that cycle fall within the identified range used in the analysis presented in Chapter 15 with due allowance for the calculational uncertainties given in subsection 4.3.3.3. Control rod requirements are given in Table 4.3-3 for the initial cycle and for a hypothetical equilibrium cycle, since these are markedly different. These latter numbers are provided for information only.

4.3.2.4 Control Requirements

To establish the required shutdown margin stated in the technical specifications under conditions where a cooldown to ambient temperature is required, concentrated soluble boron is added to the coolant. Boron concentrations for several core conditions are listed in Table 4.3-2 for the initial cycle. For core conditions including refueling, the boron concentration is well below the solubility limit. The rod cluster control assemblies are employed to bring the reactor to the shutdown condition. The minimum required shutdown margin is given in the technical specifications.

The ability to accomplish the shutdown for hot conditions is demonstrated in Table 4.3-3 by comparing the difference between the rod cluster control assembly reactivity available with an allowance for the worst stuck rod with that required for control and protection purposes. The shutdown margin includes an allowance of seven percent for analytic uncertainties which assumes the use of silver-indium-cadmium rod cluster control assemblies. Use of a seven percent uncertainty allowance on rod cluster control assembly worth is discussed and shown to be acceptable in WCAP-9217 (Reference 17). The largest reactivity control requirement appears at the EOL when the moderator temperature coefficient reaches its peak negative value as reflected in the larger power defect.

The control rods are required to provide sufficient reactivity to account for the power defect from full power to zero power and to provide the required shutdown margin. The reactivity addition

resulting from power reduction consists of contributions from Doppler effect, moderator temperature, flux redistribution, and reduction in void content as discussed below.

4.3.2.4.1 Doppler Effect

The Doppler effect arises from the broadening of U-238 and Pu-240 resonance cross-sections with an increase in effective pellet temperature. This effect is most noticeable over the range of zero power to full power due to the large pellet temperature increase with power generation.

4.3.2.4.2 Variable Average Moderator Temperature

When the core is shut down to the hot zero-power condition, the average moderator temperature changes from the equilibrium full-load value determined by the steam generator and turbine characteristics (such as steam pressure, heat transfer, tube fouling) to the equilibrium no-load value, which is based on the steam generator shell side design pressure. The design change in temperature is conservatively increased by 4°F to account for the control system dead band and measurement errors.

When the moderator coefficient is negative, there is a reactivity addition with power reduction. The moderator coefficient becomes more negative as the fuel depletes because the boron concentration is reduced. This effect is the major contributor to the increased requirement at EOL.

4.3.2.4.3 Redistribution

During full-power operation, the coolant density decreases with core height. This, together with partial insertion of control rods, results in less fuel depletion near the top of the core. Under steady-state conditions, the relative power distribution will be slightly asymmetric toward the bottom of the core. On the other hand, at hot zero-power conditions, the coolant density is uniform up the core, and there is no flattening due to Doppler effect. The result will be a flux distribution which at zero power can be skewed toward the top of the core. Since a three-dimensional calculation is performed in determining total power defect, flux redistribution is implicitly included in this calculation. An additional redistribution allowance for adversely skewed xenon distributions is included in the determination of the total control requirement specified in Table 4.3-3.

4.3.2.4.4 Void Content

A small void content in the core is due to nucleate boiling at full power. The void collapse coincident with power reduction makes a small positive reactivity contribution.

4.3.2.4.5 Rod Insertion Allowance

At full power, the MSHIM and AO banks are operated within a prescribed band of travel to compensate for small changes in boron concentration, changes in temperature, and very small changes in the xenon concentration not compensated for by a change in boron concentration. When the MSHIM banks reach a predetermined insertion or withdrawal, a change in boron concentration would be required to compensate for additional reactivity changes. Use of soluble boron is limited to fuel depletion and shutdown considerations. Since the insertion limit is set by

rod travel limit, a conservatively high calculation of the inserted worth is made, which exceeds the normally inserted reactivity.

4.3.2.4.6 Installed Excess Reactivity for Depletion

Excess reactivity is installed at the beginning of each cycle to provide sufficient reactivity to compensate for fuel depletion and fission product buildup throughout the cycle. This reactivity is controlled by the addition of soluble boron to the coolant and by burnable absorbers when necessary. The soluble boron concentration for several core configurations and the unit boron worth are given in Tables 4.3-1 and 4.3-2 for the initial cycle. Since the excess reactivity for burnup is controlled by soluble boron and/or burnable absorbers, it is not included in control rod requirements.

4.3.2.4.7 Xenon and Samarium Poisoning

Changes in xenon and samarium concentrations in the core occur at a sufficiently slow rate, even following rapid power level changes, that the resulting reactivity change can be controlled by changing the gray and/or control rod insertion. (Also see subsection 4.3.2.4.16).

4.3.2.4.8 pH Effects

Changes in reactivity due to a change in coolant pH, if any, are sufficiently small in magnitude and occur slowly enough to be controlled by the boron system WCAP-3896-8 (Reference 18).

4.3.2.4.9 Experimental Confirmation

Following a normal shutdown, the total core reactivity change during cooldown with a stuck rod has been measured on a 121-assembly, 10-foot-high core and a 121-assembly, 12-foot-high core. In each case, the core was allowed to cool down until it reached criticality simulating the steam line break accident. For the 10-foot core, the total reactivity change associated with the cooldown is over predicted by about 0.3-percent $\Delta\rho$ with respect to the measured result. This represents an error of about five percent in the total reactivity change and is about half the uncertainty allowance for this quantity. For the 12-foot core, the difference between the measured and predicted reactivity change is an even smaller 0.2 percent $\Delta\rho$. These measurements and others demonstrate the capability of the methods described in subsection 4.3.3.

4.3.2.4.10 Control

Core reactivity is controlled by means of a chemical poison dissolved in the coolant, rod cluster control assemblies, gray rod cluster assemblies and burnable absorbers as described below.

4.3.2.4.11 Chemical Shim

Boron in solution as boric acid is used to control relatively slow reactivity changes associated with:

- The moderator temperature defect in going from cold shutdown at ambient temperature to the hot operating temperature at zero power

- The transient xenon and samarium poisoning, such as that following power changes to levels below 30 percent rated thermal power

- The reactivity effects of fissile inventory depletion and buildup of long-life fission products

- The depletion of the burnable absorbers

The boron concentrations for various core conditions are presented in Table 4.3-2 for the initial cycle.

4.3.2.4.12 Rod Cluster Control Assemblies

The number of rod cluster control assemblies is shown in Table 4.3-1. The rod cluster control assemblies are used for shutdown and control purposes to offset fast reactivity changes associated with:

- The required shutdown margin in the hot zero power, stuck rod condition

- The reactivity compensation as a result of an increase in power above hot zero power (power defect, including Doppler and moderator reactivity changes)

- Unprogrammed fluctuations in boron concentration, coolant temperature, or xenon concentration (with rods not exceeding the allowable rod insertion limits)

- Reactivity changes resulting from load changes

The allowed control bank reactivity insertion is limited at full power to maintain shutdown capability. As the power level is reduced, control rod reactivity requirements are also reduced, and more rod insertion is allowed. The control bank position is monitored, and the operator is notified by an alarm if the limit is approached. The determination of the insertion limit uses conservative xenon distributions and axial power shapes. In addition, the rod cluster control assembly withdrawal pattern determined from the analyses is used in determining power distribution factors and in determining the maximum worth of an inserted rod cluster control assembly ejection accident. For further discussion, refer to the technical specifications on rod insertion limits.

Power distribution, rod ejection, and rod misalignment analyses are based on the arrangement of the shutdown and control groups of the rod cluster control assemblies shown in Figure 4.3-27. Shutdown rod cluster control assemblies are withdrawn before withdrawal of the control and AO banks is initiated. The approach to critical is initiated by using the chemical and volume control system to establish an appropriate boron concentration based upon the estimated critical condition then withdrawing the AO bank above the zero power insertion limit and finally withdrawing the control banks sequentially. The limits of rod insertion and further discussion on the basis for rod insertion limits are provided in the technical specifications.

4.3.2.4.13 Gray Rod Cluster Assemblies

The rod cluster control assembly control banks include four gray rod banks consisting of gray rod cluster assemblies (GRCAs). Gray rod cluster assemblies consist of 24 rodlets fastened at the top end to a common hub or spider. Geometrically, it is the same as a rod cluster control assembly except that 20 of the 24 rodlets are comprised of stainless steel while the remaining four rodlets are silver-indium-cadmium clad with stainless steel. The term gray rod refers to the reduced reactivity worth relative to that of a rod cluster control assembly consisting of 24 silver-indium-cadmium rodlets. The gray rod cluster assemblies are used in load follow maneuvering and provide a mechanical shim reactivity mechanism to eliminate the need for changes to the concentration of soluble boron (that is, chemical shim).

4.3.2.4.14 Burnable Absorbers

Discrete burnable absorber rods or integral fuel burnable absorber rods or both may be used to provide partial control of the excess reactivity available during the fuel cycle. In doing so, the burnable absorber loading controls peaking factors and prevents the moderator temperature coefficient from being positive at normal operating conditions. The burnable absorbers perform this function by reducing the requirement for soluble boron in the moderator at the beginning of the fuel cycle, as described previously. For purposes of illustration, the initial cycle burnable absorber pattern is shown in Figure 4.3-5. Figures 4.3-4a and 4.3-4b show the burnable absorber distribution within a fuel assembly for several burnable absorber patterns used in the 17 x 17 array. The boron in the rods is depleted with burnup but at a slow rate so that the peaking factor limits are not exceeded and the resulting critical concentration of soluble boron is such that the moderator temperature coefficient remains within the limits stated above for power operating conditions.

4.3.2.4.15 Peak Xenon Startup

Compensation for the peak xenon buildup may be accomplished using the boron control system. Startup from the peak xenon condition is accomplished with a combination of rod motion and boron dilution. The boron dilution can be made at any time, including during the shutdown period, provided the shutdown margin is maintained.

4.3.2.4.16 Load Follow Control and Xenon Control

During load follow maneuvers, power changes are primarily accomplished using control rod motion alone, as required. Control rod motion is limited by the control rod insertion limits as provided in the technical specifications and discussed in subsections 4.3.2.4.12 and 4.3.2.4.13. The power distribution is maintained within acceptable limits through limitations on control rod insertion. Reactivity changes due to the changing xenon concentration are also controlled by rod motion.

Rapid power increases (five percent/min) from part power during load follow operation are accomplished with rod motion.

The rod control system is designed to automatically provide the power and temperature control described above 30 percent rated power for most of the cycle length without the need to change

boron concentration as a result of the load maneuver. The automated mode of operation is referred to as mechanical shim (MSHIM) because of the usage of mechanical means to control reactivity and power distribution simultaneously. MSHIM operation allows load maneuvering without boron change because of the degree of allowed insertion of the control banks in conjunction with the independent power distribution control of the axial offset (AO) control bank. The worth and overlap of the MA, MB, MC, MD, M1, and M2 control banks are designed such that the AO control bank insertion will always result in a monotonically decreasing axial offset. MSHIM operation uses the MA, MB, MC, MD, M1, and M2 control banks to maintain the programmed coolant average temperature throughout the operating power range. The AO control bank is independently modulated by the rod control system to maintain a nearly constant axial offset throughout the operating power range.

The target axial offset used during MSHIM load follow operation is roughly the base load operation target axial offset less 10 percent. The negative bias is necessary to allow both positive and negative axial offset control effectiveness by the AO control bank. Extended base load operation is performed by controlling axial offset to the equilibrium target with the first moving M bank nearly fully withdrawn (at bite position) and AO bank fully withdrawn. The “bite” position is defined as the minimum control rod bank position required to provide a differential rod worth of at least 2 pcm/step.

Anticipated MSHIM load follow operation operates with two gray banks fully inserted to provide enough reactivity worth to compensate for transient reactivity effects without the need for soluble boron changes. The degree of control rod insertion under MSHIM operation allows rapid return to power without the need to change boron concentration.

4.3.2.4.17 Burnup

Control of the excess reactivity for burnup is accomplished using soluble boron and/or burnable absorbers. The boron concentration is limited during operating conditions to maintain the moderator temperature coefficient within its specified limits. A sufficient burnable absorber loading is installed at the beginning of a cycle to give the desired cycle lifetime, without exceeding the boron concentration limit. The end of a fuel cycle is reached when the soluble boron concentration approaches the practical minimum boron concentration in the range of 0 to 10 ppm.

4.3.2.4.18 Rapid Power Reduction System

The reactor power control system is designed with the capability of responding to full load rejection without initiating a reactor trip using the normal rod control system, reactor control system, and the rapid power reduction system. Load rejections requiring greater than a fifty percent reduction of rated thermal power initiate the rapid power reduction system. The rapid power reduction system utilizes preselected control rod groups and/or banks which are intentionally tripped to rapidly reduce reactor power into a range where the rod control and reactor control systems are sufficient to maintain stable plant operation. The consequences of accidental or inappropriate actuation of the rapid power reduction system is included in the cycle specific safety analysis and licensing process.

4.3.2.5 Control Rod Patterns and Reactivity Worth

The rod cluster control assemblies are designated by function as the control groups and the shutdown groups. The terms group and bank are used synonymously to describe a particular grouping of control assemblies. The rod cluster control assembly patterns are displayed in Figure 4.3-27. The control banks are labeled MA, MB, MC, MD, M1, M2, and AO with the MA, MB, MC, and MD banks comprised of gray rod control assemblies; and the shutdown banks are labeled SD1, SD2, SD3, and SD4. Each bank of more than four rod cluster control assemblies, although operated and controlled as a unit, is composed of two or more subgroups. The axial position of the rod cluster control assemblies may be controlled manually or automatically. The rod cluster control assemblies are dropped into the core following actuation of reactor trip signals.

Two criteria have been employed for selection of the control groups. First, the total reactivity worth must be adequate to meet the requirements specified in Table 4.3-3. Second, in view of the fact that these rods may be partially inserted at power operation, the total power peaking factor should be low enough to meet the power capability requirements. Analyses indicate that the first requirement can be met either by a single group or by two or more banks whose total worth equals at least the required amount. The axial power shape is more peaked following movement of a single group of rods worth three to four percent $\Delta\rho$. Therefore, control bank rod cluster control assemblies have been separated into several bank groupings. Typical control bank worth for the initial cycle are shown in Table 4.3-2.

The position of control banks for criticality under any reactor condition is determined by the concentration of boron in the coolant. On an approach to criticality, boron is adjusted so that criticality will be achieved with control rods above the insertion limit set by shutdown and other considerations. (See the technical specifications). Early in the cycle, there may also be a withdrawal limit at low power to maintain the moderator temperature coefficient within the specified limits for that power level.

Ejected rod worths for several different conditions are given in subsection 15.4.8.

Allowable deviations due to misaligned control rods are discussed in the technical specifications.

A representative differential rod worth calculation for two banks of control rods withdrawn simultaneously (rod withdrawal accident) is given in Figure 4.3-28.

Calculation of control rod reactivity worth versus time following reactor trip involves both control rod velocity and differential reactivity worth. The rod position versus time of travel after rod release assumed is given in Figure 4.3-29. For nuclear design purposes, the reactivity worth versus rod position is calculated by a series of steady-state calculations at various control positions, assuming the rods out of the core as the initial position in order to minimize the initial reactivity insertion rate. Also, to be conservative, the rod of highest worth is assumed stuck out of the core, and the flux distribution (and thus reactivity importance) is assumed to be skewed to the bottom of the core. The result of these calculations is shown in Figure 4.3-30.

The shutdown groups provide additional negative reactivity to establish adequate shutdown margin. Shutdown margin is the amount by which the core would be subcritical at hot shutdown if

the rod cluster control assemblies were tripped, but assuming that the highest worth assembly remained fully withdrawn and no changes in xenon or boron took place. The loss of control rod worth due to the depletion of the absorber material is negligible.

The values given in Table 4.3-3 show that the available reactivity in withdrawn rod cluster control assemblies provides the design bases minimum shutdown margin, allowing for the highest worth cluster to be at its fully withdrawn position. An allowance for the uncertainty in the calculated worth of N-1 rods is made before determination of the shutdown margin.

4.3.2.6 Criticality of the Reactor During Refueling

The basis for maintaining the reactor subcritical during refueling is presented in subsection 4.3.1.5, and a discussion of how control requirements are met is given in subsections 4.3.2.4 and 4.3.2.5.

4.3.2.6.1 Criticality Design Method Outside the Reactor

Criticality of fuel assemblies outside the reactor is precluded by adequate design of fuel transfer, shipping, and storage facilities and by administrative control procedures. The two principal methods of preventing criticality are limiting the fuel assembly array size and limiting assembly interaction by fixing the minimum separation between assemblies and/or inserting neutron poisons between assemblies.

The design basis for preventing criticality outside the reactor is that, including uncertainties, there is a 95 percent probability at a 95 percent confidence level that the effective multiplication factor (k_{eff}) of the fuel assembly array will be less than 0.95 as recommended in ANSI 57.2 (Reference 19) and ANSI 57.3 (Reference 20). The following conditions are assumed in meeting this design bases:

- The fuel assembly contains the highest enrichment authorized without any control rods or non-integral burnable absorber(s) and is at its most reactive point in life.
- For flooded conditions, the moderator is pure water at the temperature within the design limits which yields the largest reactivity.
- The array is either infinite in lateral extent or is surrounded by a conservatively chosen reflector, whichever is appropriate for the design.
- Mechanical uncertainties are treated either by using worst-case conditions or by performing sensitivity studies and obtaining appropriate uncertainties.
- Credit is taken for the neutron absorption in structural materials and in solid materials added specifically for neutron absorption.
- Where borated water is present, credit for the dissolved boron is not taken except under postulated accident conditions, where the double-contingency principle of ANSI N16.1-1975

is applied. This principle states that it shall require at least two unlikely, independent, and concurrent events to produce a criticality accident.

For fuel storage application, water is usually present. However, the design methodology also prevents accidental criticality when fuel assemblies are stored in the dry condition. For this case, possible sources of moderation such as those that arise during fire fighting operations are included in the analysis. The design basis k_{eff} is 0.98 as recommended in the Standard Review Plan.

The design method which determines the criticality safety of fuel assemblies outside the reactor uses the SCALE system, Rev. 4, which includes the BONAMI and NITAWL-II codes for cross sections generation and the KENO-V.a code for reactivity determination.

The 218 groups library obtained from ENDF/B-IV is the origin of the 27 groups library used in these analyses and in the modeling of the critical experiments which are the basis for the qualification of the SCALE/KENO-V.a (Reference 21) calculation system.

A set of 41 critical experiments has been analyzed using the above method to demonstrate its applicability to criticality analysis and to establish the method bias and uncertainty. The benchmark experiments cover a wide range of geometries, materials and enrichments, all of them adequate for qualifying methods to analyze light water reactor lattices (References 22 to 26).

The analysis of the 41 critical experiments results in an average Keff of 0.9938. Comparison with the measured values results in a method bias of 0.0062. The standard deviation of the set of reactivities is 0.00396. The 95/95 tolerance factor is 2.118.

The total uncertainty (TU) to be added to criticality calculations:

$$TU = \left[(ks)^2_{method} + (ks)^2_{KENO} + \sum_i (ks)^2_{mech} \right]^{1/2}$$

where:

$(ks)_{method}$ = method uncertainty as discussed above.

$(ks)_{KENO}$ = the statistical uncertainty associated with the particular KENO calculation being used.

$(ks)_{mech}$ = a series of statistical uncertainties associated with mechanical tolerances, such as thicknesses and spacings. If worst-case assumptions are used for tolerances, this term will be zero.

The criticality design criteria are met when the calculated effective multiplication factor plus the total uncertainty is less than 0.95 or, in the special case defined above, 0.98.

The analytical methods employed herein conform with ANSI N18.2 (Reference 3), Section 5.7, Fuel Handling System; ANSI N16.9 (Reference 29), ANSI 57.2 (Reference 19), subsection 6.4.2, ANSI 57.3 (Reference 20), Section 6.2.4; NRC Standard Review Plan, subsection 9.1.2, the NRC guidance, "OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications" (Reference 30).

4.3.2.7 Stability

4.3.2.7.1 Introduction

The stability of the PWR cores against xenon-induced spatial oscillations and the control of such transients are discussed extensively in References 11, 31, 32, and 33. A summary of these reports is given in the following discussion, and the design bases are given in subsection 4.3.1.6.

In a large reactor core, xenon-induced oscillations can take place with no corresponding change in the total power of the core. The oscillation may be caused by a power shift in the core which occurs rapidly by comparison with the xenon-iodine time constants. Such a power shift occurs in the axial direction when a plant load change is made by control rod motion and results in a change in the moderator density and fuel temperature distributions. Such a power shift could occur in the diametral plane of the core as a result of abnormal control action.

Due to the negative power coefficient of reactivity, PWR cores are inherently stable to oscillations in total power. Protection against total power instabilities is provided by the control and protection system, as described in Section 7.7. Hence, the discussion on the core stability will be limited to xenon-induced spatial oscillations.

4.3.2.7.2 Stability Index

Power distributions, either in the axial direction or in the X-Y plane, can undergo oscillations due to perturbations introduced in the equilibrium distributions without changing the total core power. The harmonics and the stability of the core against xenon-induced oscillations can be determined in terms of the eigenvalue of the first flux harmonics. Writing the eigenvalue ξ of the first flux harmonic as:

$$\xi = b + ic \tag{1}$$

Then b is defined as the stability index and $T = 2\pi/c$ as the oscillation period of the first harmonic. The time dependence of the first harmonic $\delta\phi$ in the power distribution can now be represented as:

$$\delta\phi(t) = A\,e^{\xi t} = a\,e^{bt}\cos ct \tag{2}$$

where A and a are constants. The stability index can also be obtained approximately by:

$$b = \frac{1}{T}\ln\frac{A_{n+1}}{A_n} \tag{3}$$

where A_n and A_{n+1} are the successive peak amplitudes of the oscillation and T is the time period between the successive peaks.

4.3.2.7.3 Prediction of the Core Stability

The core described in this report has an active fuel length that is 24 inches longer (nominal) than that for previous Westinghouse PWRs licensed in the U.S. with 157 fuel assemblies. For this reason, it is expected that this core will be as stable as the 12-foot designs with respect to radial and diametral xenon oscillations since the radial core dimensions have not changed. This core will be slightly less stable than the 12-foot, 157 assembly cores with respect to axial xenon oscillations because the active core height has been increased by 24 inches. The effect of this increase will be to decrease the burnup at which the axial stability index becomes zero (Section 4.3.2.7.4 below). The moderator temperature coefficients and the Doppler temperature coefficients of reactivity will be similar to those of previous designs. Control banks included in the core design are sufficient to dampen any xenon oscillations that may occur. Free axial xenon oscillations are not allowed to occur for a core of any height, except during special tests as described in Section 4.3.2.7.4.

4.3.2.7.4 Stability Measurements

4.3.2.7.4.1 Axial Measurements

Two axial xenon transient tests conducted in a PWR with a core height of 12 feet and 121 fuel assemblies are reported in WCAP-7964 (Reference 34) and are discussed here. The tests were performed at approximately 10 percent and 50 percent of cycle life.

Both a free-running oscillation test and a controlled test were performed during the first test. The second test at mid-cycle consisted of a free-running oscillation test only. In each of the free-running oscillation tests, a perturbation was introduced to the equilibrium power distribution through an impulse motion of the lead control bank and the subsequent oscillation period was monitored. In the controlled test conducted early in the cycle, the part-length rods were used to follow the oscillations to maintain an axial offset within the prescribed limits. The axial offset of power was obtained from the ex-core ion chamber readings (which had been calibrated against the in-core flux maps) as a function of time for both free-running tests, as shown in Figure 12 of WCAP-7964 (Reference 34)

The total core power was maintained constant during these spatial xenon tests, and the stability index and the oscillation period were obtained from a least-square fit of the axial offset data in the form of equation 2. The axial offset of power is the quantity that properly represents the axial stability in the sense that it essentially eliminates any contribution from even-order harmonics, including the fundamental mode. The conclusions of the tests follow:

- The core was stable against induced axial xenon transients, at the core average burnups of both 1550 MWD/MTU and 7700 MWD/MTU. The measured stability indices are -0.041 h^{-1} for the first test and - 0.014 h^{-1} for the second test. The corresponding oscillation periods are 32.4 and 27.2 hours, respectively.

- The reactor core becomes less stable as fuel burnup progresses, and the axial stability index is essentially zero at 12,000 MWD/MTU. However, the movable control rod systems can control axial oscillations, as described in subsection 4.3.2.7.

4.3.2.7.4.2 Measurements in the X-Y Plane

Two X-Y xenon oscillation tests were performed at a PWR plant with a core height of 12 feet and 157 fuel assemblies. The first test was conducted at a core average burnup of 1540 MWD/MTU and the second at a core average burnup of 12,900 MWD/MTU. Both of the X-Y xenon tests show that the core was stable in the X-Y plane at both burnups. The second test shows that the core became more stable as the fuel burnup increased, and Westinghouse PWRs with 121 and 157 assemblies are stable throughout their burnup cycles. The results of these tests are applicable to the 157-assembly AP1000 core, as discussed in subsection 4.3.2.7.3.

In each of the two X-Y tests, a perturbation was introduced to the equilibrium power distribution through an impulse motion of one rod cluster control unit located along the diagonal axis. Following the perturbation, the uncontrolled oscillation was monitored, using the movable detector and thermocouple system and the ex-core power range detectors. The quadrant tilt difference (QTD) is the quantity that properly represents the diametral oscillation in the X-Y plane of the reactor core in that the differences of the quadrant average powers over two symmetrically opposite quadrants essentially eliminates the contribution to the oscillation from the azimuthal mode. The quadrant tilt difference data were fitted in the form of equation 2 of subsection 4.3.2.7.2 through a least-square method. A stability index of - 0.076 hr^{-1} (per hour) with a period of 29.6 hr was obtained from the thermocouple data shown in Figure 4.3-31.

It was observed in the second X-Y xenon test that the PWR core with 157 fuel assemblies had become more stable due to an increased fuel depletion, and the stability index was not determined.

4.3.2.7.5 Comparison of Calculations with Measurements

The direct simulation of axial offset data was carried out using a licensed one-dimensional code (WCAP-7084-P-A (Reference 35)). The analysis of the X-Y xenon transient tests was performed in an X-Y geometry, using a licensed few group two-dimensional code (WCAP-7213-A (Reference 36)). Both of these codes solve the two-group, time-dependent neutron diffusion equation with time-dependent xenon and iodine concentrations. The fuel temperature and moderator density feedback is limited to a steady-state model. The X-Y calculations were performed in an average enthalpy plane.

The detailed experimental data during the tests, including the reactor power level, the enthalpy rise, and the impulse motion of the control rod assembly, as well as the plant follow burnup data, were closely simulated in the study.

The results of the stability calculation for the axial tests are compared with the experimental data in Table 4.3-5. The calculations show conservative results for both of the axial tests with a margin of approximately 0.01 hr^{-1} in the stability index.

An analytical simulation of the first X-Y xenon oscillation test shows a calculated stability index of - 0.081 hr^{-1}, in good agreement with the measured value of - 0.076 hr^{-1}. As indicated earlier, the second X-Y xenon test showed that the core had become more stable compared to the first test, and no evaluation of the stability index was attempted. This increase in the core stability in the X-Y plane due to increased fuel burnup is due mainly to the increased magnitude of the negative moderator temperature coefficient.

Previous studies of the physics of xenon oscillations, including three-dimensional analysis, are reported in a series of topical reports (References 31, 32, and 33). A more detailed description of the experimental results and analysis of the axial and X-Y xenon transient tests is presented in WCAP-7964 (Reference 34) and Section 1 of WCAP-8768 (Reference 37).

4.3.2.7.6 Stability Control and Protection

The online monitoring system provides continuous indication of current power distributions and provides guidance to the plant operator as to the timing and most appropriate action(s) to maintain stable axial power distributions. In the event the online monitoring system is out of service, the ex-core detector system is utilized to provide indications of xenon-induced spatial oscillations. The readings from the ex-core detectors are available to the operator and also form part of the protection system.

4.3.2.7.6.1 Axial Power Distribution

The rod control system automatically maintains axial power distribution within very tight axial offset bands as part of normal operation. The AO control bank is specifically designed with sufficient worth to be capable of maintaining essentially constant axial offset over the power operating range. The rod control system is also allowed to be operated in manual control in which case the operator is instructed to maintain an axial offset within a prescribed operating band, based on the ex-core detector readings. Should the axial offset be permitted to move far enough outside this band, the protection limit is encroached, and the turbine power is automatically reduced or a reactor trip signal generated, or both.

As fuel burnup progresses, PWR cores become less stable to axial xenon oscillations. However, free xenon oscillations are not allowed to occur, except for special tests. The AO control bank is sufficient to dampen and control any axial xenon oscillations present. Should the axial offset be inadvertently permitted to move far enough outside the allowed band due to an axial xenon oscillation or for any other reason, the OTΔT and/or OPΔT protection setpoint including the axial offset compensation is reached and the turbine power is automatically reduced and/or a reactor trip signal is generated.

4.3.2.7.6.2 Radial Power Distribution

The core described herein is calculated to be stable against X-Y xenon-induced oscillations during the core life.

The X-Y stability of large PWRs has been further verified as part of the startup physics test program for PWR cores with 193 fuel assemblies. The measured X-Y stability of the cores with 157 and 193 assemblies was in close agreement with the calculated stability, as discussed in

subsections 4.3.2.7.4 and 4.3.2.7.5. In the unlikely event that X-Y oscillations occur, backup actions are possible and would be implemented, if necessary, to increase the natural stability of the core. This is based on the fact that several actions could be taken to make the moderator temperature coefficient more negative, which would increase the stability of the core in the X-Y plane.

Provisions for protection against non-symmetric perturbations in the X-Y power distribution that could result from equipment malfunctions are made in the protection system design. This includes control rod drop, rod misalignment, and asymmetric loss of coolant flow.

A more detailed discussion of the power distribution control in PWR cores is presented in WCAP-7811 (Reference 11) and WCAP-8385 (Reference 12).

4.3.2.8 Vessel Irradiation

A review of the methods and analyses used in the determination of neutron and gamma ray flux attenuation between the core and the pressure vessel is provided below. A more complete discussion on the pressure vessel irradiation and surveillance program is given in Section 5.3.

The materials that serve to attenuate neutrons originating in the core and gamma rays from both the core and structural components consist of the core shroud, core barrel and associated water annuli. These are within the region between the core and the pressure vessel.

In general, few group neutron diffusion theory codes are used to determine fission power density distributions within the active core, and the accuracy of these analyses is verified by in-core measurements on operating reactors. Region and rodwise power-sharing information from the core calculations is then used as source information in two-dimensional transport calculations which compute the flux distributions throughout the reactor.

The neutron flux distribution and spectrum in the various structural components vary significantly from the core to the pressure vessel. Representative values of the neutron flux distribution and spectrum are presented in Table 4.3-6.

As discussed in Section 5.3, the irradiation surveillance program utilizes actual test samples to verify the accuracy of the calculated fluxes at the vessel.

4.3.3 Analytical Methods

Calculations required in nuclear design consist of three distinct types, which are performed in sequence:

1. Determination of effective fuel temperatures

2. Generation of microscopic few-group parameters

3. Space-dependent, few-group diffusion calculations

These calculations are carried out by computer codes which can be executed individually. Most of the codes required have been linked to form an automated design sequence which minimizes design time, avoids errors in transcription of data, and standardizes the design methods.

4.3.3.1 Fuel Temperature (Doppler) Calculations

Temperatures vary radially within the fuel rod, depending on the heat generation rate in the pellet; the conductivity of the materials in the pellet, gap, and clad; and the temperature of the coolant.

The fuel temperatures for use in most nuclear design Doppler calculations are obtained from a simplified version of the Westinghouse fuel rod design model described in subsection 4.2.1.3, which considers the effect of radial variation of pellet conductivity, expansion coefficient and heat generation rate, elastic deflection of the clad, and a gap conductance which depends on the initial fill gas, the hot open gap dimension, and the fraction of the pellet over which the gap is closed. The fraction of the gap assumed closed represents an empirical adjustment used to produce close agreement with observed reactivity data at beginning of life. Further gap closure occurs with burnup and accounts for the decrease in Doppler defect with burnup which has been observed in operating plants. For detailed calculations of the Doppler coefficient, such as for use in xenon stability calculations, a more sophisticated temperature model is used, which accounts for the effects of fuel swelling, fission gas release, and plastic clad deformation.

Radial power distributions in the pellet as a function of burnup are obtained from LASER (WCAP-6073, Reference 38) calculations.

The effective U-238 temperature for resonance absorption is obtained from the radial temperature distribution by applying a radially dependent weighing function. The weighing function was determined from REPAD (WCAP-2048, Reference 39) Monte Carlo calculations of resonance escape probabilities in several steady-state and transient temperature distributions. In each case, a flat pellet temperature was determined which produced the same resonance escape probability as the actual distribution. The weighing function was empirically determined from these results.

The effective Pu-240 temperature for resonance absorption is determined by a convolution of the radial distribution of Pu-240 densities from LASER burnup calculations and the radial weighing function. The resulting temperature is burnup dependent, but the difference between U-238 and Pu-240 temperatures, in terms of reactivity effects, is small.

The effective pellet temperature for pellet dimensional change is that value which produces the same outer pellet radius in a virgin pellet as that obtained from the temperature model. The effective clad temperature for dimensional change is its average value.

The temperature calculational model has been validated by plant Doppler defect data, as shown in Table 4.3-7, and Doppler coefficient data, as shown in Figure 4.3-32. Stability index measurements also provide a sensitive measure of the Doppler coefficient near full power (subsection 4.3.2.7).

4.3.3.2 Macroscopic Group Constants

PHOENIX-P (WCAP-11596-P-A, Reference 40) has been used for generating the macroscopic cross sections needed for the spatial few group codes. PHOENIX-P or other NRC approved lattice codes will be used for reload designs.

PHOENIX-P has been approved by the NRC as a lattice code for the generation of macroscopic and microscopic few group cross sections for PWR analysis. (See WCAP-11596-P-A, Reference 40). PHOENIX-P is a two-dimensional, multigroup, transport-based lattice code capable of providing necessary data for PWR analysis. Since it is a dimensional lattice code, PHOENIX-P does not rely on pre-determined spatial/spectral interaction assumptions for the heterogeneous fuel lattice and can provide a more accurate multigroup spatial flux solution than versions (ARK) of LEOPARD/CINDER.

The solution for the detailed spatial flux and energy distribution is divided into two major steps in PHOENIX-P (See References 40 and 41). First, a two-dimensional fine energy group nodal solution is obtained, coupling individual subcell regions (e.g., pellet, clad and moderator) as well as surrounding pins, using a method based on Carlvik's collision probability approach and heterogeneous response fluxes which preserve the heterogeneous nature of the pin cells and their surroundings. The nodal solution provides an accurate and detailed local flux distribution, which is then used to homogenize the pin cells spatially to few groups.

Then, a standard S_4 discrete ordinates calculation solves for the angular distribution, based on the group-collapsed and homogenized cross sections from the first step. These S_4 fluxes normalize the detailed spatial and energy nodal fluxes, which are then used to compute reaction rates, power distributions and to deplete the fuel and burnable absorbers. A standard B1 calculation evaluates the fundamental mode critical spectrum, providing an improved fast diffusion coefficient for the core spatial codes.

PHOENIX-P employs either a 42 or 70 energy group library derived mainly from the ENDF/B-V files (Reference 21). This library was designed to capture the integral properties of the multigroup data properly during group collapse and to model important resonance parameters properly. It contains neutronics data necessary for modelling fuel, fission products, cladding and structural materials, coolant, and control and burnable absorber materials present in PWRs.

Group constants for burnable absorber cells, control rod cells, guide thimbles and instrumentation thimbles, or other non-fuel cells, can be obtained directly from PHOENIX-P without any adjustments such as those required in the cell or 1D lattice codes.

PHOENIX-P has been validated through an extensive qualification effort which includes calculation-measurement comparison of the Strawbridge-Barry critical experiments (See References 42 and 43), the KRITZ high temperature criticals (Reference 44), the AEC sponsored B&W criticals (References 45 through 47) and measured actinide isotopic data from fuel pins irradiated in the Saxton and Yankee Rowe cores (References 48 through 53). In addition, calculation-measurement comparisons have been made to operating reactor data measured during startup tests and during normal power operation.

Validation of the cross section method is based on analysis of critical experiments, isotopic data, plant critical boron concentration data, and control rod worth measurement data such as that shown in Table 4.3-8.

Confirmatory critical experiments on burnable absorber rods are described in WCAP-7806 (Reference 42).

4.3.3.3 Spatial Few-Group Diffusion Calculations

The 3D ANC code (see WCAP-10965-P-A, Reference 57) permits the introduction of advanced fuel designs with axial heterogeneities, such as axial blankets and part-length burnable absorbers, and allows such features to be modeled explicitly. The three dimensional nature of this code provides both radial and axial power distribution. For some applications, the updated version APOLLO (see WCAP-13524 Reference 60) of the PANDA code (see WCAP-7084-P-A Reference 35) will continue to be used for axial calculations, and a two-dimensional collapse of 3D ANC that properly accounts for the three-dimensional features of the fuel is used for X-Y calculations.

Spatial few group calculations are carried out to determine the critical boron concentrations and power distributions. The moderator coefficient is evaluated by varying the inlet temperature in the same kind of calculations as those used for power distribution and reactivity predictions.

Validation of the reactivity calculations is associated with validation of the group constants themselves, as discussed in subsection 4.3.3.2. Validation of the Doppler calculations is associated with the fuel temperature validation discussed in subsection 4.3.3.1. Validation of the moderator coefficient calculations is obtained by comparison with plant measurements at hot zero power conditions, similar to that shown in Table 4.3-9.

Axial calculations are used to determine differential control rod worth curves (reactivity versus rod insertion) and to demonstrate load follow capability. Group constants are obtained from the three-dimensional nodal model by flux-volume weighing on an axial slicewise basis. Radial bucklings are determined by varying parameters in the buckling model while forcing the one-dimensional model to reproduce the axial characteristics (axial offset, midplane power) of the three-dimensional model.

Validation of the spatial codes for calculating power distributions involves the use of in-core and ex-core detectors and is discussed in subsection 4.3.2.2.7.

As discussed in subsection 4.3.3.2, calculation-measurement comparisons have been made to operating reactor data measured during startup tests and during normal power operation. These comparisons include a variety of core geometries and fuel loading patterns, and incorporate a reasonable extreme range of fuel enrichment, burnable absorber loading, and cycle burnup. Qualification data identified in Reference 40 indicate small mean and standard deviations relative to measurement which are equal to or less than those found in previous reviews of similar or parallel approved methodologies. For the reload designs the spatial codes described above, other NRC approved codes, or both are used.

4.3.4 Combined License Information

This section contains no requirement for additional information to be provided in support of the combined license. Combined License applicants referencing the AP1000 certified design will address changes to the reference design of the fuel, burnable absorber rods, rod cluster control assemblies, or initial core design from that presented in the DCD.

4.3.5 References

1. Bordelon, F. M, et al., "Westinghouse Reload Safety Evaluation Methodology," WCAP-9272-P-A (Proprietary) and WCAP-9273-NP-A (Nonproprietary), July 1985.

[*2. Davidson, S. L. (Ed.), "Fuel Criteria Evaluation Process," WCAP-12488-P-A (Proprietary) and WCAP-14204-A - (Nonproprietary), October 1994.*]*

3. ANSI N18.2-1973, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants."

4. Beard, C. L. and Morita, T., "BEACON: Core Monitoring and Operations Support System," WCAP-12472-P-A (Proprietary) and WCAP-12473-A (Nonproprietary), August 1994; Addendum 1, May 1996; and Addendum 2, March 2001.

5. Gangloff, W. C. and Loftus, W. D., "Westinghouse Anticipated Transients Without Reactor Trip Analysis," WCAP-8330, August 1974.

6. Reference deleted.

7. Spier, E. M., "Evaluation of Nuclear Hot Channel Factor Uncertainties," WCAP-7308-L-P-A (Proprietary) and WCAP-7308-L-A, (Nonproprietary), June 1988.

8. Hellman, J. M., ed. "Fuel Densification Experimental Results and Model for Reactor Application," WCAP-8218-P-A (Proprietary) and WCAP-8219-A (Nonproprietary), March 1975.

9. Meyer, R. O., "The Analysis of Fuel Densification," Division of Systems Safety, U.S. Nuclear Regulatory Commission, NUREG-0085, July 1976.

10. Hellman, J. M., Olson, C. A., and Yang, J. W., "Effects of Fuel Densification Power Spikes on Clad Thermal Transients," WCAP-8359; July 1974.

11. Moore, J. S., "Power Distribution Control of Westinghouse Pressurized Water Reactors," WCAP-7811, December 1971.

12. Morita, T., et al., "Power Distribution Control and Load Following Procedures," WCAP-8385 (Proprietary) and WCAP-8403 (Nonproprietary), September 1974.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

13. Miller, R. W., et al., “Relaxation of Constant Axial Offset Control, F_Q Surveillance Technical Specification,” WCAP-10216-P-A, (Proprietary) and WCAP-10217-A, (Nonproprietary) Revision 1A, February 1994.

14. McFarlane, A. F., “Power Peaking Factors,” WCAP-7912-P-A (Proprietary) and WCAP-7912-A (Nonproprietary), January 1975.

15. Meyer, C. E., and Stover, R. L., “Incore Power Distribution Determination in Westinghouse Pressurized Water Reactors,” WCAP-8498, July 1975.

16. Warren, H. D., “Rhodium In-Core Detector Sensitivity Depletion, Cycles 2-6,” EPRI-NP-3814, December 1984.

17. Henderson, W. B., “Results of the Control Rod Worth Program,” WCAP-9217 (Proprietary) and WCAP-9218 (Nonproprietary), October 1977.

18. Cermak, J. O., et al., “Pressurized Water Reactor pH - Reactivity Effect Final Report,” WCAP-3696-8 (EURAEC-2074), October 1968.

19. ANSI N57.2-1983, “Design Objectives for LWR Spent Fuel Storage Facilities at Nuclear Power Stations.”

20. ANSI N57.3-1983, “Design Requirements for New Fuel Storage Facilities at Light Water Reactor Plants.”

21. NUREG/CR-0200, “SCALE: A Modular Code System for Performing Standardized Computer Analyses for Licensing Evaluation,” Oak Ridge National Laboratory; Rev. 4, January 1990.

22. “Critical Separation Between Subcritical Clusters of 2.35% w/o U235 Enriched UO_2 Rods in Water with Fixed Neutron Poisons,” PNL-2438, Batelle Pacific Northwest Laboratory.

23. “Critical Separation Between Subcritical Clusters of 4.29% w/o U235 Enriched UO_2 Rods in Water with Fixed Neutron Poisons,” NUREG/CR-0073 (PNL-2615), Batelle Pacific Northwest Laboratory, May 1978.

24. “Critical Experiments with Lattices of 4.75 w/o U235 Enriched UO_2 Rods in Water,” Nucl. Sci. and Eng., Vol. 71, 154-163 (1979).

25. G. S. Hoovler et al., “Critical Experiments Supporting Close Proximity Water Storage of Power Reactor Fuel,” Nuclear Technology, Vol. 51, pp 217 (December 1980).

26. NEDO-32028 “MCNP-Light Water Reactor Critical Benchmarks,” S. Sitaraman, March 1992.

27. Bierman, S. R., et al., “Criticality Experiments with Subcritical Clusters of 2.35 wt% and 4.31 wt% ^{235}U Enriched UO_2 Rods in Water at a Water-to-Fuel Volume Ratio of 1.6,” PNL-3314, July 1980.

28. Thomas, J. T., “Critical Three-Dimensional Arrays of U (93.2)--Metal Cylinders,” Nuclear Science and Engineering 52, pp 350-359, 1973.

29. ANSI N16.9-1975, “Validation of Calculational Methods for Nuclear Criticality Safety.”

30. NRC Letter “OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications,” from Grimes, B. K., to all power reactor licenses, April 14, 1978.

31. Poncelet, C. G., and Christie, A. M., “Xenon-Induced Spatial Instabilities in Large Pressurized Water Reactors,” WCAP-3680-20 (EURAEC-1974), March 1968.

32. Skogen, F. B., and McFarlane, A. F., “Control Procedures for Xenon-Induced X-Y Instabilities in Large Pressurized Water Reactors,” WCAP-3680-21 (EURAEC-2111), February 1969.

33. Skogen, F. B., and McFarlane, A. F., “Xenon-Induced Spatial Instabilities in Three Dimensions,” WCAP-3680-22 (EURAEC-2116), September 1969.

34. Lee, J. C., et al., “Axial Xenon Transient Tests at the Rochester Gas and Electric Reactor,” WCAP-7964, June 1971.

35. Barry, R. F., and Minton, G., “The PANDA Code,” WCAP-7048-P-A (Proprietary) and WCAP-7757-A (Nonproprietary), February 1975.

36. Barry, R. F., and Altomare, S., “The TURTLE 24.0 Diffusion Depletion Code,” WCAP-7213-A (Proprietary) and WCAP-7758-A (Non-Proprietary), February 1975.

37. Eggleston, F. T., “Safety-Related Research and Development for Westinghouse Pressurized Water Reactors, Program Summaries - Winter 1977 - Summer 1978,” WCAP-8768, Revision 2, October 1978.

38. Poncelet, C. G., “LASER - A Depletion Program for Lattice Calculations Based on MUFT and THERMOS,” WCAP-6073, April 1966.

39. Olhoeft, J. E., “The Doppler Effect for a Non-Uniform Temperature Distribution in Reactor Fuel Elements,” WCAP-2048, July 1962.

40. Nguyen, T. Q., et al., “Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores,” WCAP-11596-P-A (Proprietary) and WCAP-11597-A (Nonproprietary), June 1988.

41. Mildrum, C. M., Mayhue, L. T., Baker, M. M., and Isaac, P. G., “Qualification of the PHOENIX/POLCA Nuclear Design and Analysis Program for Boiling Water Reactors,” WCAP-10841 (Proprietary), and WCAP-10842 (Nonproprietary), June 1985.

42. Barry, R. F., "Nuclear Design of Westinghouse Pressurized Water Reactors with Burnable Poison Rods," WCAP-7806, December 1971.

43. Strawbridge, L. E., and Barry, R. F., "Criticality Calculation for Uniform Water-Moderated Lattices," Nuclear Science and Engineering 23, p. 58, 1965.

44. Persson, R., Blomsjo, E., and Edenius, M., "High Temperature Critical Experiments with H_2O Moderated Fuel Assemblies in KRITZ," Technical Meeting No. 2/11, NUCLEX 72, 1972.

45. Baldwin, M. N., and Stern, M. E., "Physics Verification Program Part III, Task 4: Summary Report," BAW-3647-20, March 1971.

46. Baldwin, M. N., "Physics Verification Program Part III, Task 11: Quarterly Technical Report January-March 1974," BAW-3647-30, July 1974.

47. Baldwin, M. N., "Physics Verification Program Part III, Task 11: Quarterly Technical Report July-September 1974," BAW-3647-31, February 1975.

48. Nodvik, R. J., "Saxton Core II Fuel Performance Evaluation Part II: Evaluation of Mass Spectrometric and Radiochemical Analyses of Irradiated Saxton Plutonium Fuel," WCAP-3385-56 Part II, July 1970.

49. Smalley, W. R., "Saxton Core II - Fuel Performance Evaluation Part I: Materials," WCAP-3386-56 Part I, September 1971.

50. Goodspeed, R. C., "Saxton Plutonium Project - Quarterly Progress Report for the Period Ending June 20, 1973," WCAP-3385-36, July 1973.

51. Crain, H. H., "Saxton Plutonium Project - Quarterly Progress Report for the Period Ending September 30, 1973," WCAP-3385-37, December 1973.

52. Melehan, J. B., "Yankee Core Evaluation Program Final Report," WCAP-3017-6094, January 1971.

53. Reference deleted.

54. Reference deleted.

55. Reference deleted.

56. Reference deleted.

57. Davidson, S. L., (Ed.), et al., "ANC: A Westinghouse Advanced Nodal Computer Code," WCAP-10965-P-A (Proprietary) and WCAP-10966-A (Nonproprietary), September 1986.

58. Leamer, R. D., et al., "PuO_2-U O_2 Fueled Critical Experiments," WCAP-3726-1, July 1967.

59. Davidson, S. L., et al., "Assessment of Clad Flattening and Densification Power Spike Factor Elimination in Westinghouse Nuclear Fuel," WCAP-13589-A (Proprietary) and WCAP-14297-A (Nonproprietary), March 1995.

60. Yarbrough, M. B., Liu, Y. S., Paterline, D. L., Hone, M. J., "APOLLO - A One Dimensional Neutron Theory Program," WCAP-13524, Revision 1 (Proprietary), August 1994 and WCAP-14952-NP-A, Revision 1A (Nonproprietary), September 1977.

61. NTD-NRC-94-4275, Westinghouse's Interpretation of Staff's Position on Extended Burnup, August 29, 1994.

Table 4.3-1 (Sheet 1 of 3)

[*REACTOR CORE DESCRIPTION (FIRST CYCLE)*]*

Active core	
Equivalent diameter (in.)	*119.7*
Active fuel height first core (in.), cold	*168*
Height-to-diameter ratio	*1.40*
Total cross section area (ft^2)	*78.14*
H_2O/U molecular ratio, cell, cold	*2.40*
Reflector thickness and composition	
Top - water plus steel (in.)	*~10*
Bottom - water plus steel (in.)	*~10*
Side - water plus steel (in.)	*~15*
Fuel assemblies	
Number	*157*
Rod array	*17 x 17*
Rods per assembly	*264*
Rod pitch (in.)	*0.496*
Overall transverse dimensions (in.)	*8.426 x 8.426*
Fuel weight, as UO_2 (lb)	*211,588*
Zircaloy clad weight (lb)	*43,105*
Number of grids per assembly	
Top and bottom - (Ni-Cr-Fe Alloy 718)	*2[(a)]*
Intermediate	*8 ZIRLO™*
Intermediate flow mixing (IFM)	*4 ZIRLO™*
Number of guide thimbles per assembly	*24*
Composition of guide thimbles	*Zircaloy-4 or ZIRLO™*
Diameter of guide thimbles, upper part (in.)	*0.442 ID x 0.482 OD*
Diameter of guide thimbles, lower part (in.)	*0.397 ID x0.439 OD*
Diameter of instrument guide thimbles (in.)	*0.442 ID x 0.482 OD*

Note:
(a) The top grid may be fabricated of either nickel-chromium-iron Alloy 718 or ZIRLO™

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 4.3-1 (Sheet 2 of 3)

[REACTOR CORE DESCRIPTION (FIRST CYCLE)]*

Fuel rods	
Number	*41,448*
Outside diameter (in.)	*0.374*
Diameter gap (in.)	*0.0065*
Clad thickness (in.)	*0.0225*
Clad material	*ZIRLO™*
Fuel pellets	
Material	*UO_2 sintered*
Density (% of theoretical) (nominal)	*95.5*
Fuel enrichments (weight %)	
Region 1	*2.35*
Region 2	*3.40*
Region 3	*4.45*
Diameter (in.)	*0.3225*
Length (in.)	*0.387*
Mass of UO_2 per ft of fuel rod (lb/ft)	*0.366*
Rod Cluster Control Assemblies	
Neutron absorber	*Ag-In-Cd*
Diameter (in.)	*0.341*
Density (lb/in.^{3})	*Ag-In-Cd 0.367*
Cladding material	*Type 304, cold-worked SS*
Clad thickness (in.)	*0.0185*
Number of clusters, full-length	*53*
Number of absorber rods per cluster	*24*
Gray Rod Cluster Assemblies	
Neutron absorber	*Ag-In-Cd/304SS*
Diameter (in.)	*0.341*
Density (lb/in.^{3})	*Ag-In-Cd 0.367 / 304SS 0.285*
Cladding material	*Type 304, cold-worked SS*
Clad thickness (in.)	*0.0185*
Number of clusters, full-length	*16*
Number of absorber rods per cluster	*4 Ag-In-Cd / 20 304SS*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 4.3-1 (Sheet 3 of 3)

[REACTOR CORE DESCRIPTION (FIRST CYCLE)]*

Discrete Burnable absorber rods (first core)	
Number	*1558*
Material	*Borosilicate Glass*
OD (in.)	*0.381*
Inner tube, OD (in.)	*0.1815*
Clad material	*Stainless Steel*
Inner tube material	*Stainless Steel*
B_{10} content (Mg/cm)	*6.24*
Absorber length (in.)	*145*
Integral Fuel Burnable Absorbers (first core)	
Number	*8832*
Type	*IFBA*
Material	*Boride Coating*
B_{10} Content (Mg/cm)	*0.772*
Absorber length (in.)	*152*
Excess reactivity	
Maximum fuel assembly K4 (cold, clean, unborated water)	*1.328*
Maximum core reactivity K_{eff} (cold, zero power, beginning of cycle, zero soluble boron)	*1.205*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 4.3-2 (Sheet 1 of 2)

[NUCLEAR DESIGN PARAMETERS (FIRST CYCLE)]*

Core average linear power, including densification effects (kW/ft)		*5.71*
Total heat flux hot channel factor, F_Q		*2.60*
Nuclear enthalpy rise hot channel factor, $F^N_{\Delta H}$		*1.65*
Reactivity coefficients [(a)]	*Design Limits*	*Best Estimate*
Doppler-only power coefficients (see Figure 15.1-5) (pcm/% power)[(b)]		
Upper curve	*-19.4 to -12.6*	*-13.3 to -8.7*
Lower curve	*-10.2 to -6.7*	*-11.3 to -8.4*
Doppler temperature coefficient (pcm/°F)[(b)]	*-3.5 to -1.0*	*-2.1 to -1.3*
Moderator temperature coefficient (pcm/°F)[(b)]	*0 to -40*	*0 to -35*
Boron coefficient (pcm/ppm)[(b)]	*-13.5 to -5.0*	*-10.5 to -6.9*
Rodded moderator density (pcm/g/cm^3*)*[(b)]	$\leq 0.47x10^5$	$\leq 0.45x10^5$
Delayed neutron fraction and lifetime, β_{eff}		*0.0075(0.0044)*[(c)]
Prompt Neutron Lifetime, ℓ^**,* μs		*19.8*
Control rods		
Rod requirements		*See Table 4.3-3*
Maximum ejected rod worth		*See Chapter 15*
Bank worth HZP no overlap (pcm)[(b)]	*BOL, Xe Free*	*EOL, Eq. Xe*
MA Bank	*299*	*205*
MB Bank	*131*	*198*
MC Bank	*204*	*270*
MD Bank	*309*	*198*
M1 Bank	*858*	*632*
M2 Bank	*933*	*1405*
AO Bank	*2027*	*1571*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 4.3-2 (Sheet 2 of 2)

[NUCLEAR DESIGN PARAMETERS (FIRST CYCLE)]*

Typical Hot Channel Factors $F^N_{\Delta H}$	*BOL*	*EOL*
Unrodded	*1.40*	*1.33*
MA bank	*1.46*	*1.38*
MA + MB banks	*1.49*	*1.42*
MA + MB + MC banks	*1.50*	*1.31*
MA + MB + MC + MD banks	*1.50*	*1.37*
MA + MB + MC + MD + M1 banks	*1.52*	*1.45*
AO bank	*1.60*	*1.52*
Boron concentrations (ppm)		
Zero power, k_{eff} *= 0.99, cold*[(d)] *RCCAs out*		*1574*
Zero power, k_{eff} *= 0.99, hot*[(e)] *RCCAs out*		*1502*
Design basis refueling boron concentration		*2500*
Zero power, $k_{eff} \leq 0.95$*, cold*[(d)] *RCCAs in*		*1179*
Zero power, k_{eff} *= 1.00, hot*[(e)] *RCCAs out*		*1382*
Full power, no xenon, k_{eff} *= 1.0, hot RCCAs out*		*1184*
Full power, equilibrium xenon, k = 1.0, hot RCCAs out		*827*
Reduction with fuel burnup		
First cycle (ppm/(GWD/MTU))[(f)]		*See Figure 4.3-3*
Reload cycle (ppm/(GWD/MTU))		*~40*

Notes:

(a) Uncertainties are given in subsection 4.3.3.3.

(b) 1 pcm = 10^{-5} $\Delta\rho$ *where* $\Delta\rho$ *is calculated form two statepoint values of* k_{eff} *by ln* (k_1/k_2)*.*

(c) Bounding lower value used for safety analysis.

(d) Cold means 68°F, 1 atm.

(e) Hot means 557°F, 2250 psia.

(f) 1 GWD = 1000 MWD. During the first cycle, a large complement of burnable absorbers is present which significantly reduce the boron depletion rate compared to reload cycles.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 4.3-3

[REACTIVITY REQUIREMENTS FOR ROD CLUSTER CONTROL ASSEMBLIES]*

Reactivity Effects (Percent)	*BOL (First Cycle)*	*EOL (First Cycle)*	*EOL Representative (Equilibrium Cycle)*
1. Control requirements			
Total power defect (%Δρ)[(a)]	*1.89*	*2.54*	*3.02*
Redistribution (adverse xenon only) (%Δρ)	*0.27*	*0.40*	*0.32*
Rod insertion allowance (%Δρ)	*2.00*	*2.00*	*2.00*
2. Total control (%Δρ)	*4.16*	*4.94*	*5.34*
3. Estimated RCCA worth (69 rods)			
a. All full-length assemblies inserted (%Δρ)	*12.69*	*10.89*	*10.64*
b. All assemblies but one (highest worth) inserted (%Δρ)	*10.49*	*9.27*	*9.35*
4. Estimated RCCA credit with 7 percent adjustment to accommodate uncertainties, item 3b minus 7 percent (%Δρ)	*9.76*	*8.62*	*8.70*
5. Shutdown margin available, item 4 minus item 2 (%Δρ)[(b)]	*5.60*	*3.68*	*3.36*

Notes:

(a) Includes void effects

(b) The design basis minimum shutdown is 1.60 percent

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Table 4.3-4

BENCHMARK CRITICAL EXPERIMENTS[(a)]

Critical Number	General Description	Enrichment ^{235}U w/o	Reflector	Separating Material	Soluble Boron (ppm)	Measured K_{eff}	KENO K_{eff}	KENO K_{eff} One Sigma
1	UO2 Rod Lattice	2.46	water	water	0	1.0002	0.9966	0.0024
2	UO2 Rod Lattice	2.46	water	water	1037	1.0001	0.9914	0.0019
3	UO2 Rod Lattice	2.46	water	water	764	1.0000	0.9943	0.0019
4	UO2 Rod Lattice	2.46	water	B4C pins	0	0.9999	0.9871	0.0022
5	UO2 Rod Lattice	2.46	water	B4C pins	0	1.0000	0.9902	0.0022
6	UO2 Rod Lattice	2.46	water	B4C pins	0	1.0097	0.9948	0.0021
7	UO2 Rod Lattice	2.46	water	B4C pins	0	0.9998	0.9886	0.0021
8	UO2 Rod Lattice	2.46	water	B4C pins	0	1.0083	0.9973	0.0021
9	UO2 Rod Lattice	2.46	water	water	0	1.0030	0.9966	0.0021
10	UO2 Rod Lattice	2.46	water	water	143	1.0001	0.9973	0.0021
11	UO2 Rod Lattice	2.46	water	stainless steel	514	1.0000	0.9992	0.0020
12	UO2 Rod Lattice	2.46	water	stainless steel	217	1.0000	1.0031	0.0021
13	UO2 Rod Lattice	2.46	water	borated aluminum	15	1.0000	0.9939	0.0022
14	UO2 Rod Lattice	2.46	water	borated aluminum	92	1.0001	0.9882	0.0022
15	UO2 Rod Lattice	2.46	water	borated aluminum	395	0.9998	0.9854	0.0021
16	UO2 Rod Lattice	2.46	water	borated aluminum	121	1.0001	0.9848	0.0022
17	UO2 Rod Lattice	2.46	water	borated aluminum	487	1.0000	0.9892	0.0021
18	UO2 Rod Lattice	2.46	water	borated aluminum	197	1.0002	0.9944	0.0022
19	UO2 Rod Lattice	2.46	water	borated aluminum	634	1.0002	0.9956	0.0020
20	UO2 Rod Lattice	2.46	water	borated aluminum	320	1.0003	0.9893	0.0022
21	UO2 Rod Lattice	2.46	water	borated aluminum	72	0.9997	0.9900	0.0022
22	UO2 Rod Lattice	2.35	water	borated aluminum	0	1.0000	0.9980	0.0024
23	UO2 Rod Lattice	2.35	water	stainless steel	0	1.0000	0.9933	0.0022
24	UO2 Rod Lattice	2.35	water	water	0	1.0000	0.9920	0.0024
25	UO2 Rod Lattice	2.35	water	stainless steel	0	1.0000	0.9877	0.0022
26	UO2 Rod Lattice	2.35	water	borated aluminum	0	1.0000	0.9912	0.0022
27	UO2 Rod Lattice	2.35	water	B4C	0	1.0000	0.9921	0.0021
28	UO2 Rod Lattice	4.31	water	stainless steel	0	1.0000	0.9968	0.0023
29	UO2 Rod Lattice	4.31	water	water	0	1.0000	0.9963	0.0025
30	UO2 Rod Lattice	4.31	water	stainless steel	0	1.0000	0.9950	0.0026
31	UO2 Rod Lattice	4.31	water	borated aluminum	0	1.0000	0.9952	0.0025
32	UO2 Rod Lattice	4.31	water	borated aluminum	0	1.0000	1.0006	0.0024
33	U-metal Cylinders	93.2	bare	air	0	1.0000	0.9968	0.0023
34	U-metal Cylinders	93.2	bare	air	0	1.0000	1.0082	0.0025
35	U-metal Cylinders	93.2	bare	air	0	1.0000	0.9935	0.0024
36	U-metal Cylinders	93.2	bare	air	0	1.0000	0.9982	0.0028
37	U-metal Cylinders	93.2	bare	air	0	1.0000	0.9916	0.0025
38	U-metal Cylinders	93.2	bare	air	0	1.0000	0.9922	0.0025
39	U-metal Cylinders	93.2	bare	plexiglass	0	1.0000	0.9972	0.0025
40	U-metal Cylinders	93.2	paraffin	plexiglass	0	1.0000	0.9973	0.0029
41	U-metal Cylinders	93.2	bare	plexiglass	0	1.0000	1.0019	0.0027
42	U-metal Cylinders	93.2	paraffin	plexiglass	0	1.0000	1.0103	0.0025
43	U-metal Cylinders	93.2	paraffin	plexiglass	0	1.0000	1.0021	0.0026
44	U-metal Cylinders	93.2	paraffin	plexiglass	0	1.0000	1.0022	0.0029

Note:

(a) See References 24, 25, 26, 27, and 28

Table 4.3-5

STABILITY INDEX FOR PRESSURIZED WATER REACTOR CORES WITH A 12-FOOT HEIGHT

Burnup (MWD/MTU)	F_Z	C_B (ppm)	Axial Stability Index (h^{-1})	
			Experiment	Calculated
1550	1.34	1065	-0.0410	-0.0320
7700	1.27	700	-0.0140	-0.0060
5090[(a)]			-0.0325	-0.0255
			Radial Stability Index (h^{-1})	
			Experiment	Calculated
2250[(b)]			-0.0680	-0.0700

Notes:
(a) Four-loop plant, 12-foot core in cycle 1, axial stability test
(b) Four-loop plant, 12-foot core in cycle 1, radial (X-Y) stability test

Table 4.3-6

TYPICAL NEUTRON FLUX LEVELS ($n/cm^2/s$) AT FULL POWER

	E ≥ 1.0 MeV	1.00 MeV > E ≥5.53 KeV	5.53 KeV > E ≥0.625 eV	E < 0.625 eV
Core center	$1.12x10^{14}$	$1.76x10^{14}$	$1.28x10^{14}$	$5.47x10^{13}$
Core outer radius at midheight	$3.86x10^{13}$	$6.08x10^{13}$	$4.42x10^{13}$	$1.83x10^{13}$
Core top, on axis	$3.02x10^{13}$	$4.75x10^{13}$	$3.46x10^{13}$	$2.17x10^{13}$
Core bottom, on axis	$2.92x10^{13}$	$4.59x10^{13}$	$3.34x10^{13}$	$2.40x10^{13}$
Pressure vessel ID azimuthal peak	$4.71x10^{10}$	$8.4x10^{10}$	$5.56x10^{10}$	$5.32x10^{10}$

Table 4.3-7

COMPARISON OF MEASURED AND CALCULATED DOPPLER DEFECTS

Plant	Fuel	Core Burnup (MWD/MTU)	Measured (pcm)[a]	Calculated (pcm)
1	Air filled	1800	1700	1710
2	Air filled	7700	1300	1440
3	Air and helium filled	8460	1200	1210

Note:
(a) pcm = 10^5 x ln (k_2/k_1)

Table 4.3-8

COMPARISON OF MEASURED AND CALCULATED AG-IN-CD ROD WORTH

2-Loop Plant, 121 Assemblies, 10-ft Core		**Measured (pcm)**	**Calculated (pcm)**
Group B		1885	1893
Group A		1530	1649
Shutdown group		3050	2917
ESADA critical, 0.69-in. pitch[(a)] 2 w/o PuO_2, 8% Pu-240, 9 control rods			
6.21-in. rod separation		2250	2250
2.07-in. rod separation		4220	4160
1.38-in. rod separation		4100	4019
Benchmark Critical Experiment Hafnium Control Rod Worth			
Control Rod Configuration	**No. of Fuel Rods**	**Measured[(b)] Worth (Δppm B-10)**	**Calculated[(b)] Worth (Δppm B-10)**
9 hafnium rods	1192	138.3	141.0

Notes:
(a) Report in WCAP-3726-1 (Reference 58).
(b) Calculated and measured worth are given in terms of an equivalent charge in B-10 concentration.

Table 4.3-9

COMPARISON OF MEASURED AND CALCULATED MODERATOR COEFFICIENTS AT HZP, BOL

Plant Type/ Control Bank Configuration	Measured α_{iso} [(a)] (pcm/°F)	Calculated α_{iso} (pcm/°F)
3-loop, 157-assembly, 12-ft core		
D at 160 steps	-0.50	-0.50
D in, C at 190 steps	-3.01	-2.75
D in, C at 28 steps	-7.67	-7.02
B, C, and D in	-5.16	-4.45
2-loop, 121-assembly, 12-ft core		
D at 180 steps	+0.85	+1.02
D in, C at 180 steps	-2.40	-1.90
C and D in, B at 165 steps	-4.40	-5.58
B, C, and D in, A at 174 steps	-8.70	-8.12
4-loop, 193-assembly, 12-ft core		
ARO	-0.52	-1.2
D in	-4.35	-5.7
D and C in	-8.59	-10.0
D, C, and B in	-10.14	-10.55
D, C, B, and A in	-14.63	-14.45

Note:
(a) Isothermal coefficients, which include the Doppler effect in the fuel.

$$\alpha_{iso} = 10^5 \ln \frac{k_2}{k_1} / \Delta T \,^\circ F$$

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1							3	3	3						
2					3	3	3	1	3	3	3				
3				3	3	2	1	2	1	2	3	3			
4			3	1	2	1	2	1	2	1	2	1	3		
5		3	3	2	1	2	1	2	1	2	1	2	3	3	
6		3	2	1	2	1	2	1	2	1	2	1	2	3	
7	3	3	1	2	1	2	1	2	1	2	1	2	1	3	3
8	3	1	2	1	2	1	2	1	2	1	2	1	2	1	3
9	3	3	1	2	1	2	1	2	1	2	1	2	1	3	3
10		3	2	1	2	1	2	1	2	1	2	1	2	3	
11		3	3	2	1	2	1	2	1	2	1	2	3	3	
12			3	1	2	1	2	1	2	1	2	1	3		
13				3	3	2	1	2	1	2	3	3			
14					3	3	3	1	3	3	3				
15							3	3	3						

90° (left side, row 8)

0° (bottom, column H)

LEGEND

R	Region Identifier

Region	Enrichment
1	2.35 w/o
2	3.40 w/o
3	4.45 w/o

Figure 4.3-1

Fuel Loading Arrangement

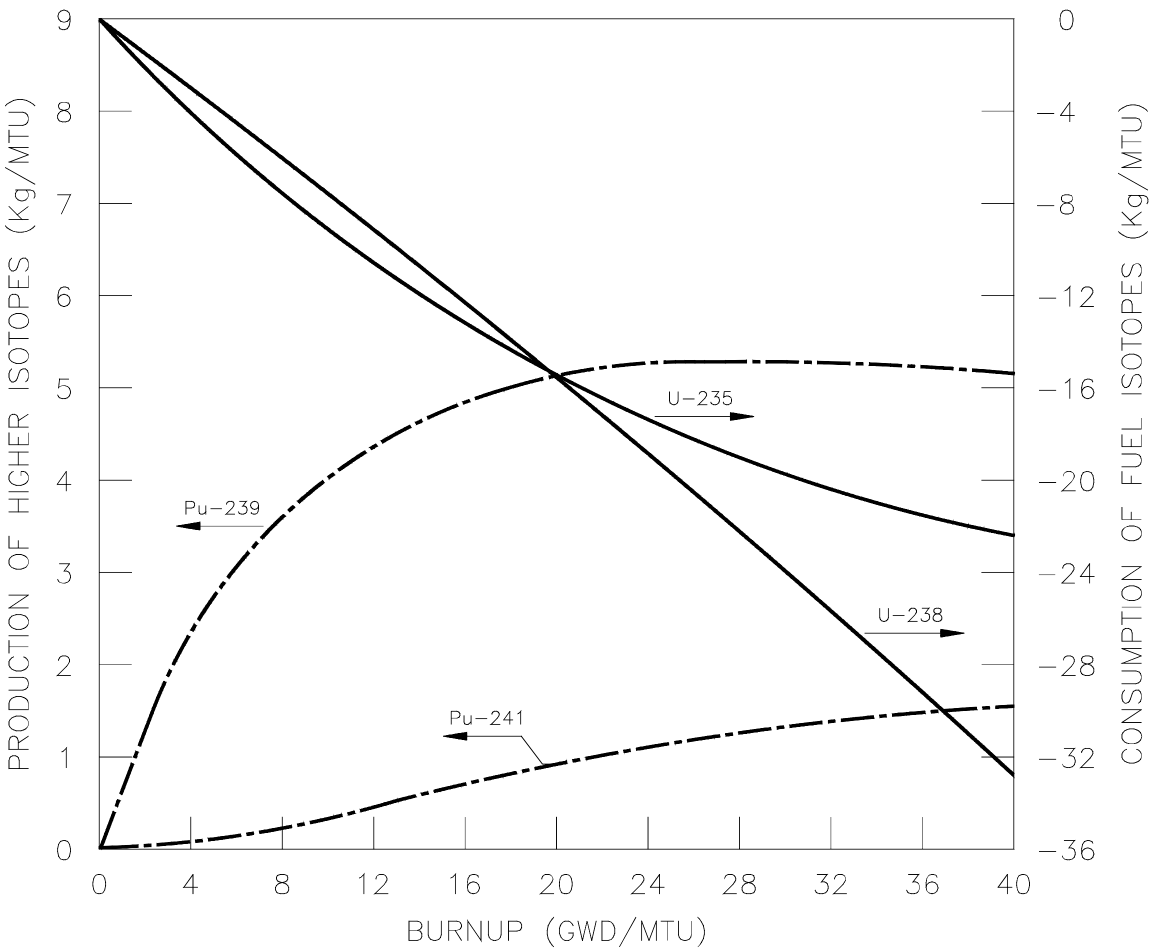


Figure 4.3-2

Typical Production and Consumption of Higher Isotopes

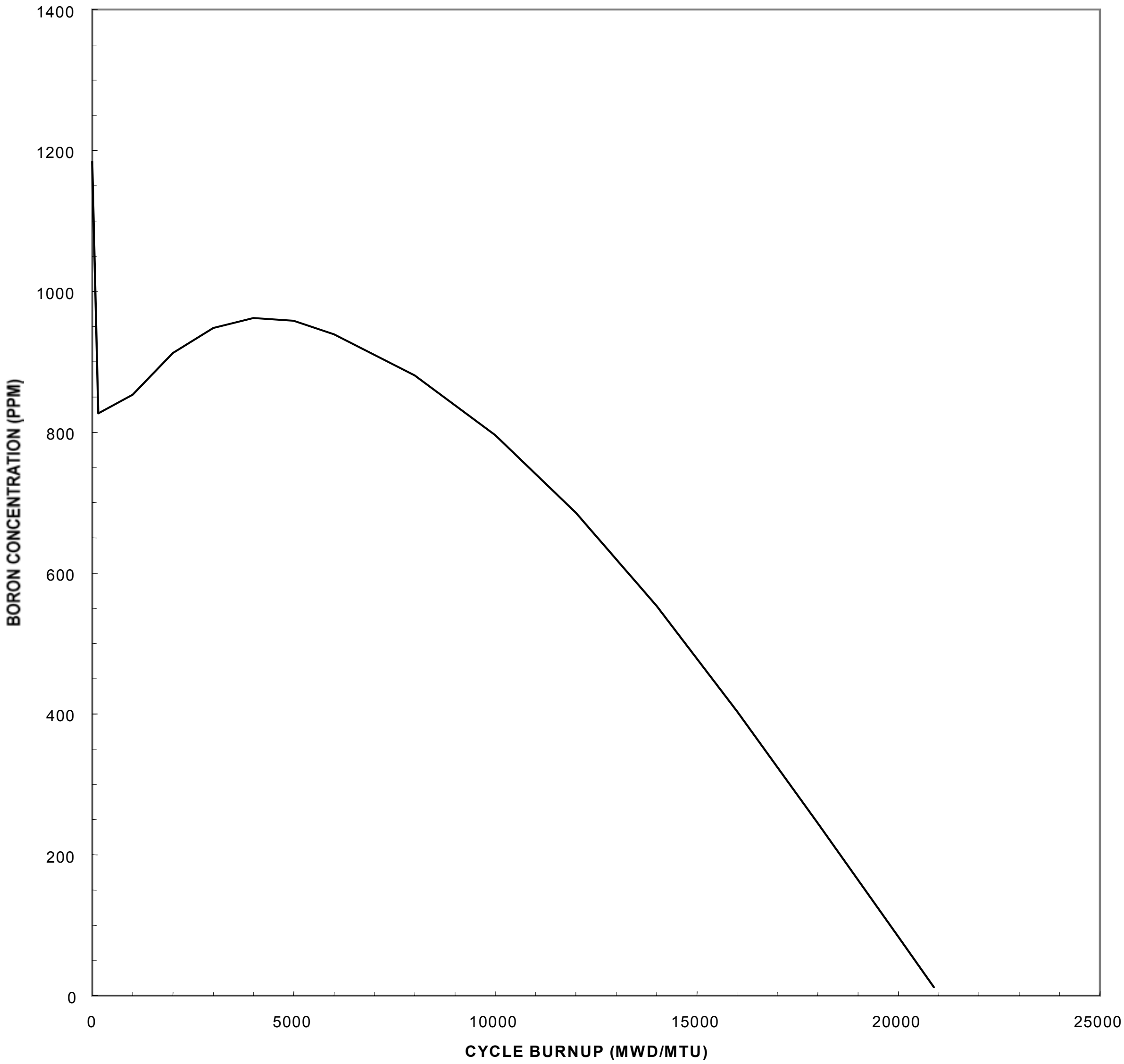


Figure 4.3-3

Cycle 1 Soluble Boron Concentration Versus Burnup

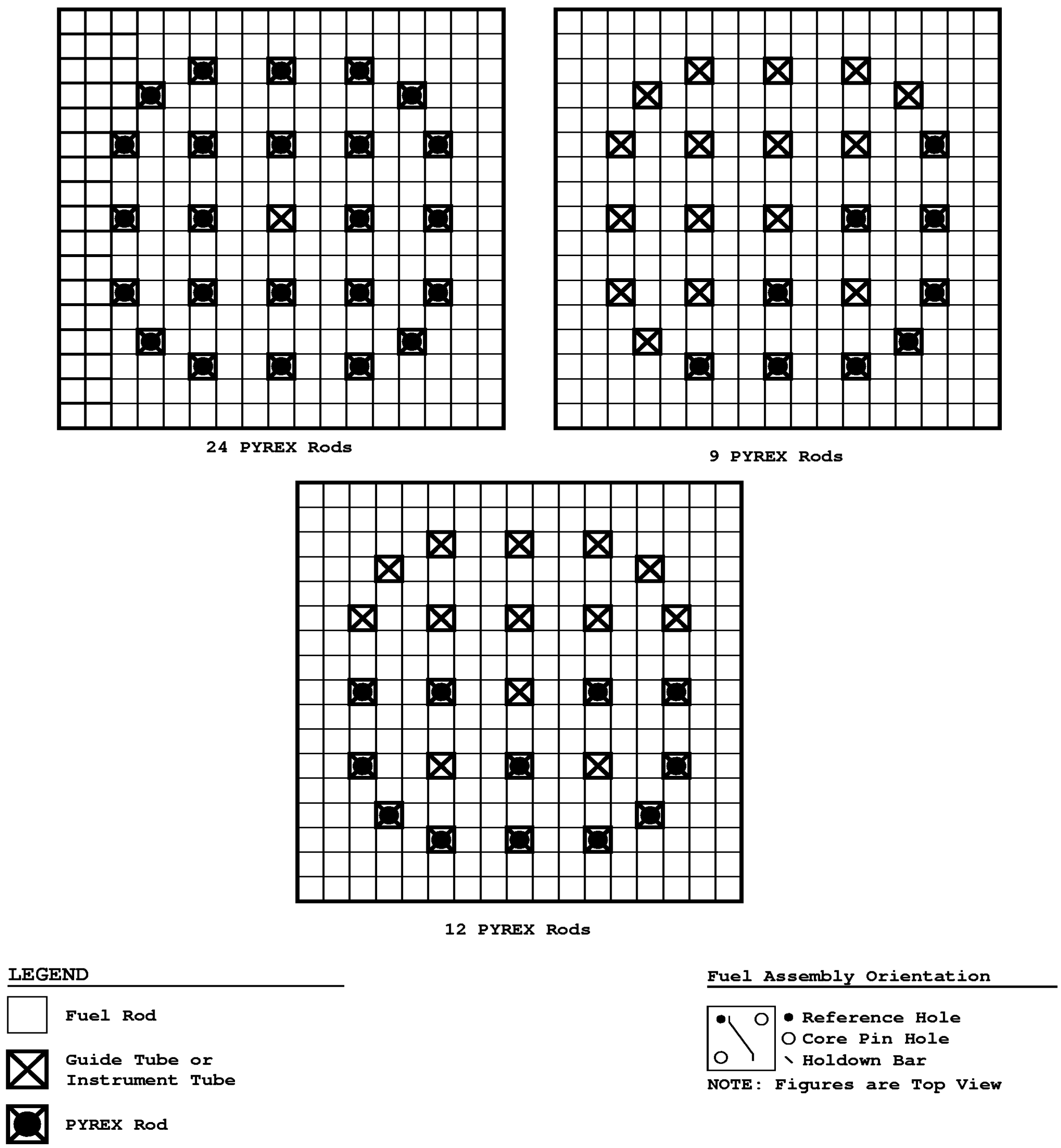


Figure 4.3-4a

Cycle 1 Assembly Burnable Absorber Patterns

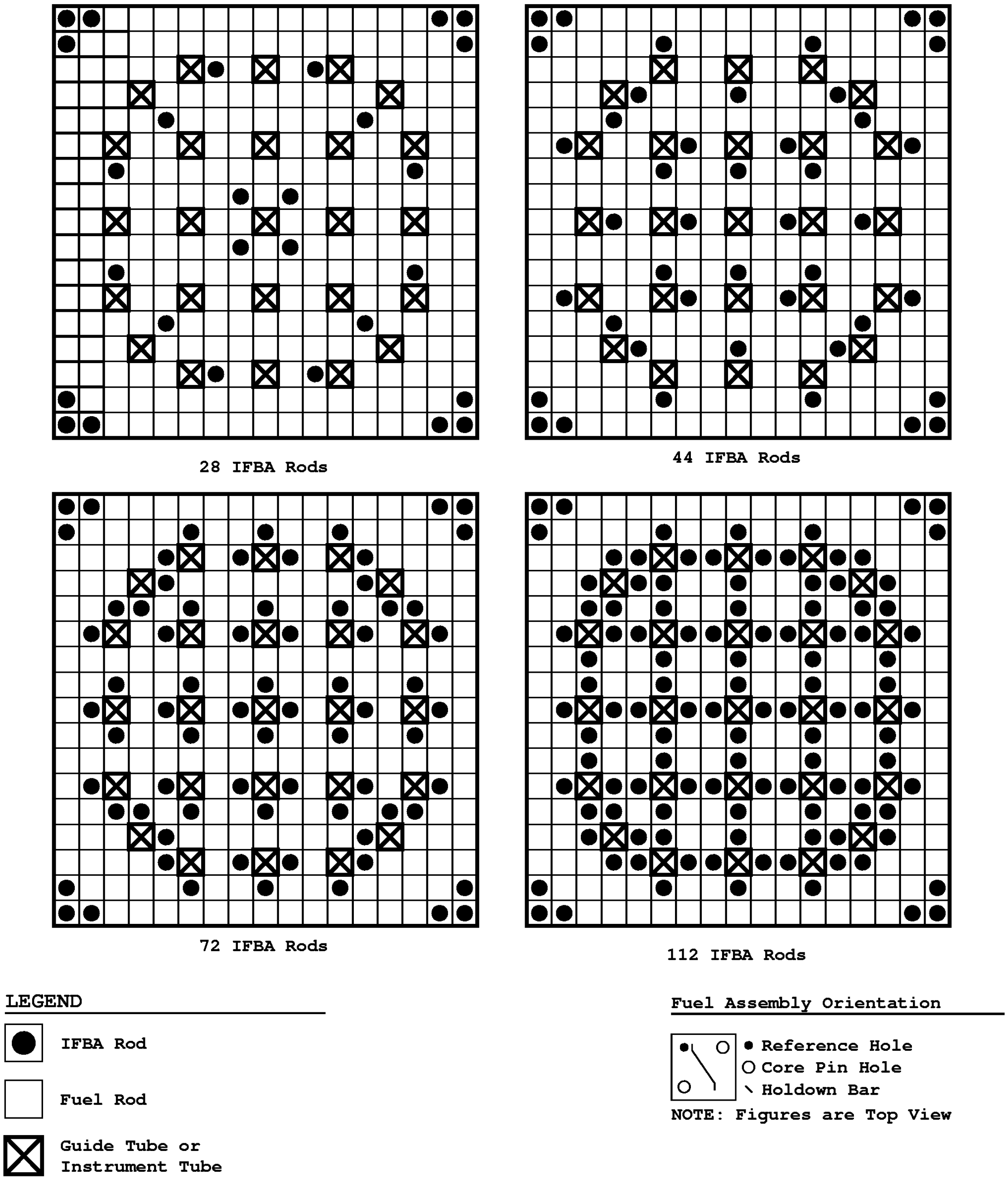
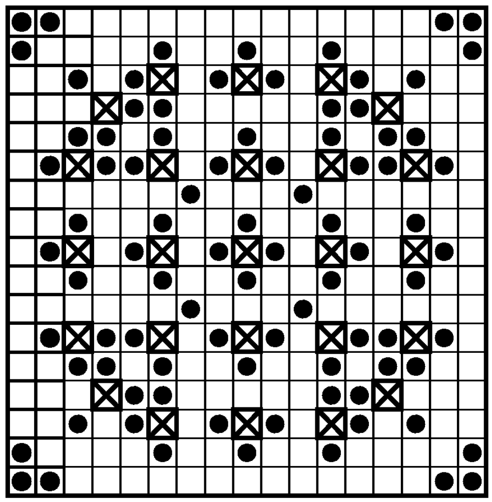


Figure 4.3-4b (Sheet 1 of 2)

Cycle 1 Assembly Burnable Absorber Patterns

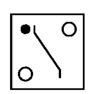


88 IFBA Rods

LEGEND

- IFBA Rod
- Fuel Rod
- Guide Tube or Instrument Tube

Fuel Assembly Orientation



- ● Reference Hole
- ○ Core Pin Hole
- ⟍ Holdown Bar

NOTE: Figures are Top View

Figure 4.3-4b (Sheet 2 of 2)

Cycle 1 Assembly Burnable Absorber Patterns

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1							9P 88I	12P 88I	9P 88I						
2					6SS 112I	112I	24P 72I		24P 72I	112I	112I				
3				112I	112I	24P 28I		1PS 23P 28I		24P 28I	112I	112I			
4			112I	28I	24P 44I		24P 88I		24P 88I		24P 44I	28I	112I		
5		112I	112I	24P 44I		24P 88I		24P 88I		24P 88I		24P 44I	112I	112I	
6		112I	24P 28I		24P 88I		24P 88I		24P 88I		24P 88I		24P 28I	112I	
7	9P 88I	24P 72I		24P 88I		24P 88I		24P 88I		24P 88I		24P 88I		24P 72I	9P 88I
8 (90°)	12P 88I		24P 28I		24P 88I		24P 88I		24P 88I		24P 88I		24P 28I		12P 88I
9	9P 88I	24P 72I		24P 88I		24P 88I		24P 88I		24P 88I		24P 88I		24P 72I	9P 88I
10		112I	24P 28I		24P 88I		24P 88I		24P 88I		24P 88I		24P 28I	112I	
11		112I	112I	24P 44I		24P 88I		24P 88I		24P 88I		24P 44I	112I	112I	
12			112I	28I	24P 44I		24P 88I		24P 88I		24P 44I	28I	112I		
13				112I	112I	24P 28I		1PS 23P 28I		24P 28I	112I	112I			
14					112I	112I	24P 72I		24P 72I	112I	6SS 112I				
15							9P 88I	12P 88I	9P 88I						

0°

TYPE	TOTAL
##P...(NUMBER OF PYREX RODLETS)..............	1558
##I...(TOTAL NUMBER OF FRESH IFBA RODS)......	8832
#PS...(NUMBER OF PRIMARY SOURCE RODLETS)........	2
#SS...(NUMBER OF SECONDARY SOURCE RODLETS).....	12

Figure 4.3-5

Burnable Absorber, Primary, and Secondary Source Assembly Locations

1.279				
1.154	1.273			
1.268	1.142	1.250		
1.137	1.250	1.111	1.193	
1.254	1.113	1.203	1.033	0.859
1.161	1.168	1.026	1.041	0.630
0.957	0.913	0.815	0.561	
0.541	0.436			

CALCULATED F-DELTA-H = 1.406

KEY: VALUE REPRESENTS ASSEMBLY RELATIVE POWER

Figure 4.3-6

Normalized Power Density Distribution Near Beginning of Life, Unrodded Core, Hot Full Power, No Xenon

1.291				
1.159	1.285			
1.279	1.147	1.260		
1.140	1.259	1.114	1.200	
1.258	1.112	1.206	1.028	0.868
1.153	1.167	1.015	1.030	0.632
0.959	0.903	0.806	0.558	
0.542	0.436			

CALCULATED F-DELTA-H = 1.403

KEY: VALUE REPRESENTS ASSEMBLY RELATIVE POWER

Figure 4.3-7

Normalized Power Density Distribution Near Beginning of Life, Unrodded Core, Hot Full Power, Equilibrium Xenon

1.311				
1.166	1.271			
1.283	1.101	0.971		
1.161	1.257	1.062	1.152	
1.321	1.153	1.221	0.989	0.654
1.232	1.241	1.052	1.022	0.579
1.041	0.970	0.849	0.571	
0.592	0.473			

CALCULATED F-DELTA-H = 1.484

KEY: VALUE REPRESENTS ASSEMBLY RELATIVE POWER

Figure 4.3-8

Normalized Power Density Distribution Near Beginning of Life, Gray Bank M0 Inserted, Hot Full Power, Equilibrium Xenon

1.091				
1.182	1.091			
1.090	1.179	1.089		
1.173	1.086	1.170	1.074	
1.069	1.154	1.077	1.123	0.908
1.104	1.023	1.096	1.170	0.745
0.868	0.954	0.923	0.681	
0.588	0.491			

CALCULATED F-DELTA-H = 1.333

KEY: VALUE REPRESENTS ASSEMBLY RELATIVE POWER

Figure 4.3-9

Normalized Power Density Distribution Near Middle of Life, Unrodded Core, Hot Full Power, Equilibrium Xenon

0.977				
1.091	0.981			
0.985	1.100	0.992		
1.110	0.998	1.114	1.000	
1.012	1.128	1.014	1.099	0.890
1.137	1.023	1.111	1.143	0.774
0.978	1.114	0.995	0.737	
0.801	0.665			

CALCULATED F-DELTA-H = 1.324

KEY: VALUE REPRESENTS ASSEMBLY RELATIVE POWER

Figure 4.3-10

Normalized Power Density Distribution Near End of Life, Unrodded Core, Hot Full Power, Equilibrium Xenon

0.993				
1.100	0.974			
0.990	1.063	0.770		
1.132	0.998	1.069	0.958	
1.057	1.166	1.023	1.049	0.671
1.206	1.079	1.144	1.129	0.709
1.049	1.184	1.040	0.751	
0.862	0.713			

CALCULATED F-DELTA-H = 1.411

KEY: VALUE REPRESENTS ASSEMBLY RELATIVE POWER

Figure 4.3-11

Normalized Power Density Distribution Near End of Life, Gray Bank M0 Inserted, Hot Full Power, Equilibrium Xenon

1.136																
1.145	1.175															
1.167	1.208	1.263														
1.178	1.232	1.315														
1.185	1.253	1.341	1.380	1.378												
1.188	1.277		1.370	1.384												
1.187	1.258	1.330	1.334	1.352	1.387	1.364										
1.185	1.256	1.324	1.330	1.348	1.384	1.363	1.365									
1.189	1.276		1.358	1.378		1.394	1.396									
1.185	1.255	1.323	1.329	1.348	1.383	1.362	1.365	1.396	1.364							
1.186	1.257	1.328	1.333	1.350	1.385	1.363	1.362	1.393	1.361	1.361						
1.186	1.275		1.367	1.382		1.384	1.382		1.381	1.382						
1.182	1.250	1.338	1.377	1.375	1.381	1.349	1.345	1.375	1.344	1.347	1.378	1.371				
1.175	1.228	1.311		1.376	1.366	1.330	1.326	1.354	1.325	1.328	1.363	1.372				
1.163	1.204	1.258	1.310	1.337		1.325	1.320		1.318	1.323		1.333	1.306	1.253		
1.140	1.171	1.203	1.227	1.248	1.272	1.253	1.250	1.271	1.249	1.252	1.269	1.244	1.222	1.198	1.165	
1.131	1.140	1.162	1.173	1.180	1.183	1.182	1.180	1.184	1.179	1.180	1.180	1.176	1.169	1.157	1.134	1.124

Figure 4.3-12

Rodwise Power Distribution in a Typical Assembly (G-9)
Near Beginning of Life
Hot Full Power, Equilibrium Xenon, Unrodded Core

0.935																
0.930	0.935															
0.930	0.944	0.969														
0.931	0.951	1.000														
0.932	0.958	1.008	1.024	1.010												
0.935	0.979		1.019	1.022												
0.935	0.960	1.003	0.992	0.996	1.019	0.997										
0.935	0.962	1.002	0.990	0.995	1.019	0.997	0.998									
0.949	0.991		1.020	1.024		1.028	1.029									
0.936	0.963	1.003	0.990	0.995	1.019	0.998	0.998	1.029	0.999							
0.936	0.961	1.004	0.993	0.997	1.020	0.998	0.998	1.028	0.998	0.999						
0.937	0.981		1.020	1.024		1.021	1.020		1.021	1.022						
0.934	0.960	1.010	1.026	1.012	1.024	0.998	0.997	1.026	0.997	0.999	1.025	1.014				
0.933	0.953	1.002		1.026	1.021	0.994	0.992	1.022	0.993	0.995	1.022	1.028				
0.933	0.946	0.972	1.002	1.011		1.006	1.005		1.006	1.007		1.013	1.005	0.975		
0.933	0.938	0.947	0.954	0.961	0.982	0.963	0.965	0.994	0.966	0.964	0.984	0.963	0.956	0.949	0.941	
0.939	0.933	0.933	0.934	0.936	0.939	0.938	0.939	0.952	0.939	0.939	0.940	0.937	0.936	0.936	0.936	0.942

Figure 4.3-13

Rodwise Power Distribution in a Typical Assembly (G-9)
Near End of Life
Hot Full Power, Equilibrium Xenon, Unrodded Core

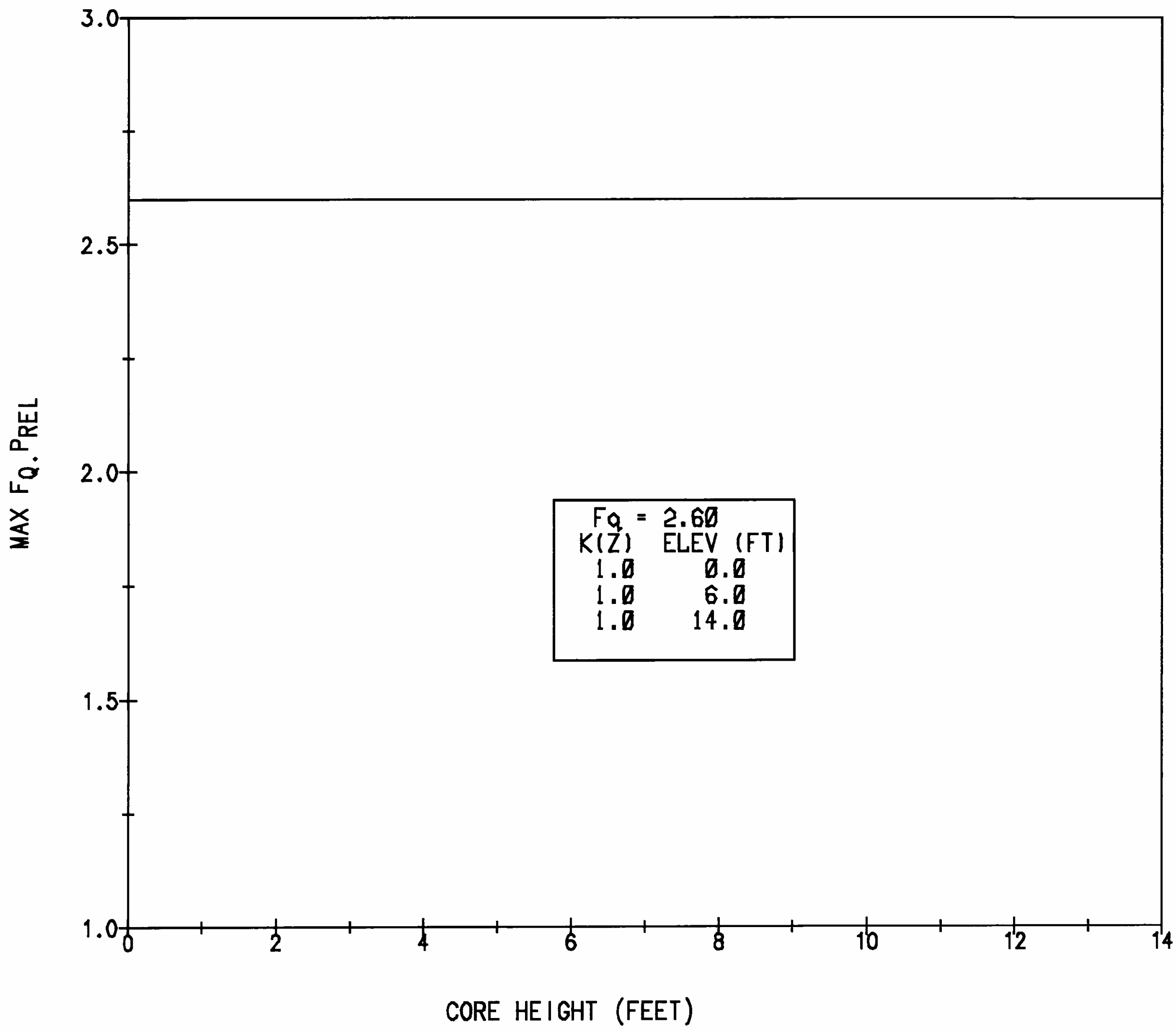


Figure 4.3-14

Maximum F_Q x Power versus Axial Height During Normal Operation

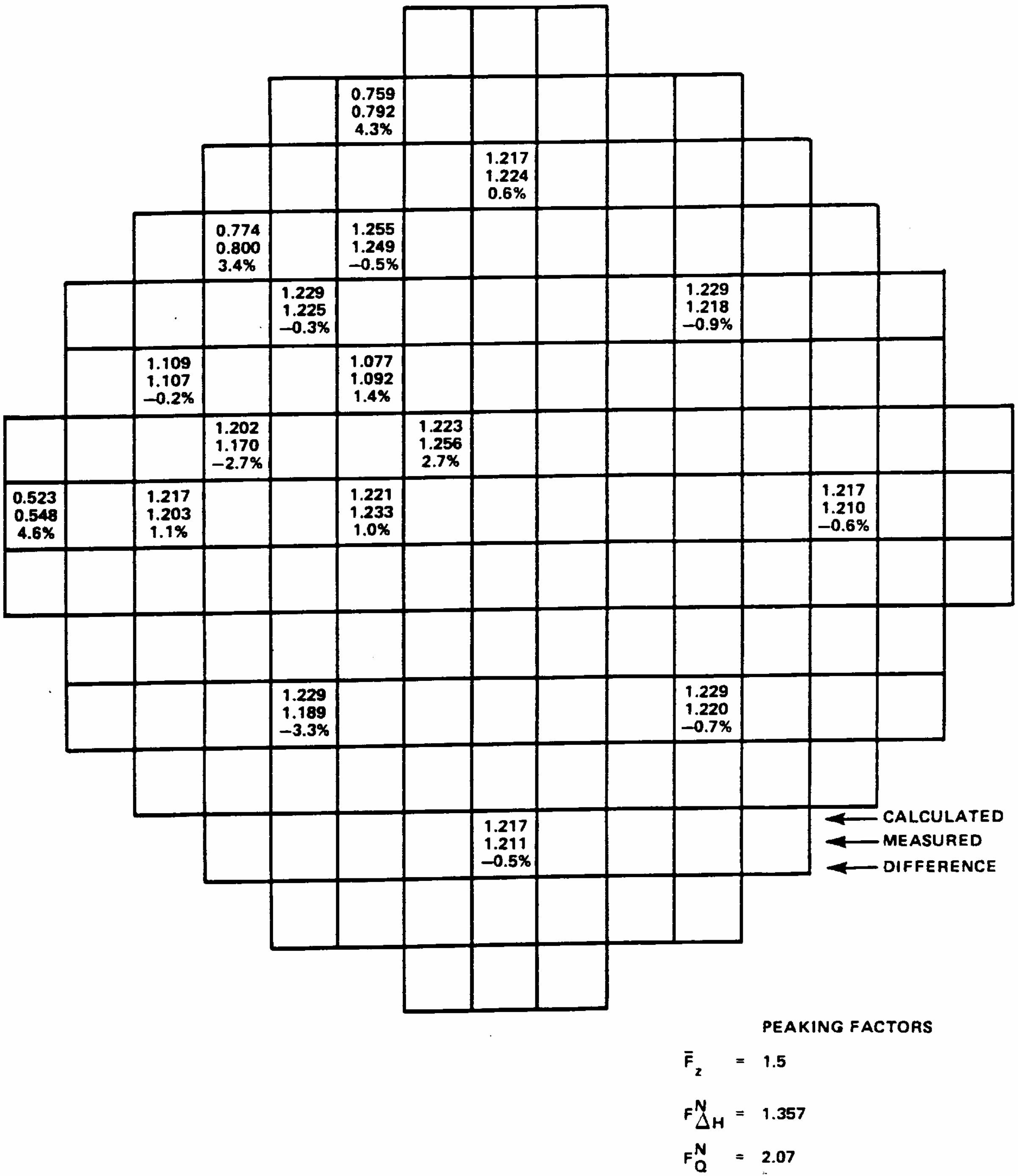


Figure 4.3-15

Typical Comparison Between Calculated and Measured Relative Fuel Assembly Power Distribution

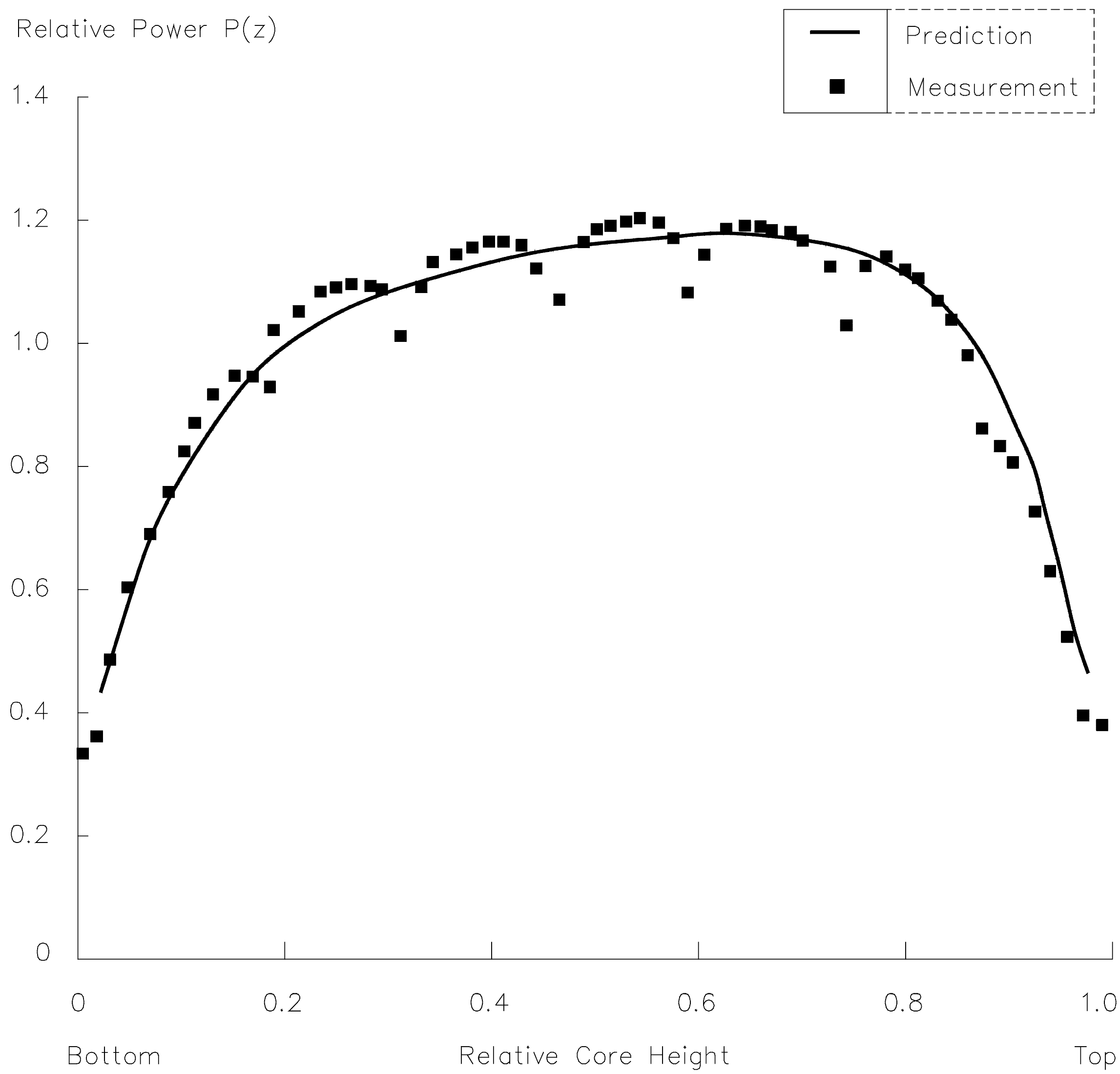


Figure 4.3-16

Typical Calculated versus Measured Axial Power Distribution

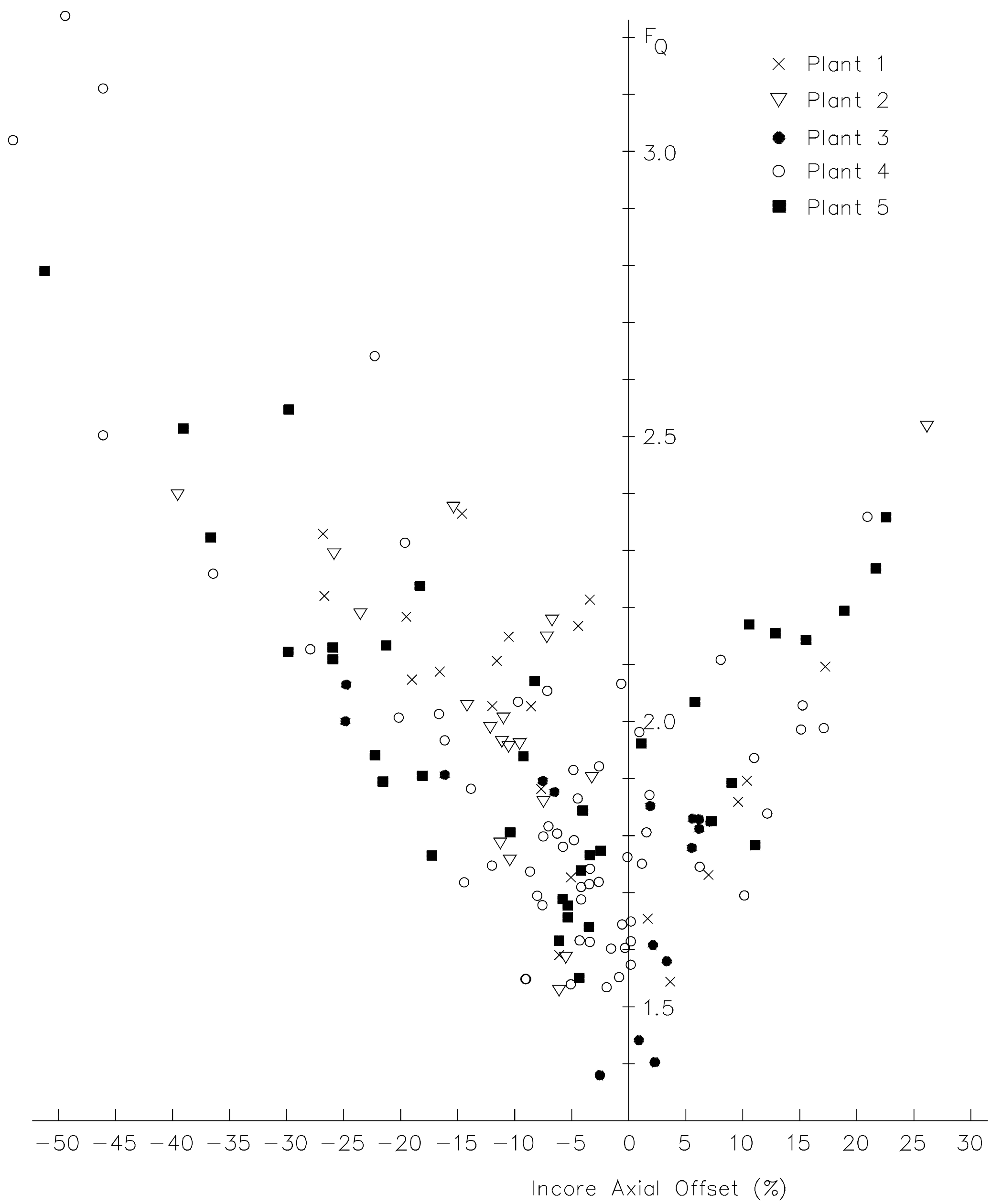


Figure 4.3-17

Measured F_Q Values versus Axial Offset for Full Power Rod Configurations

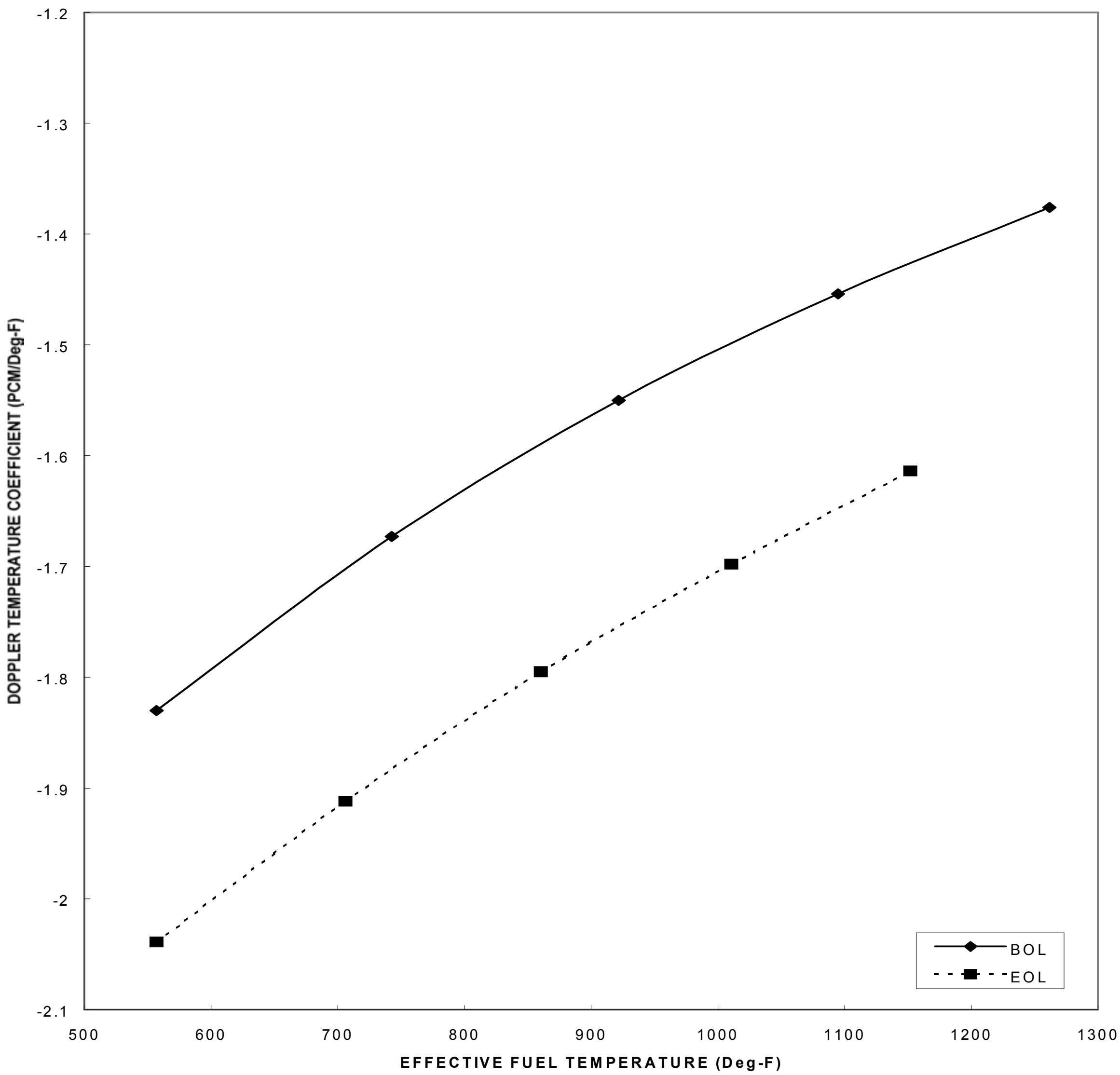


Figure 4.3-18

Typical Doppler Temperature Coefficient at BOL and EOL

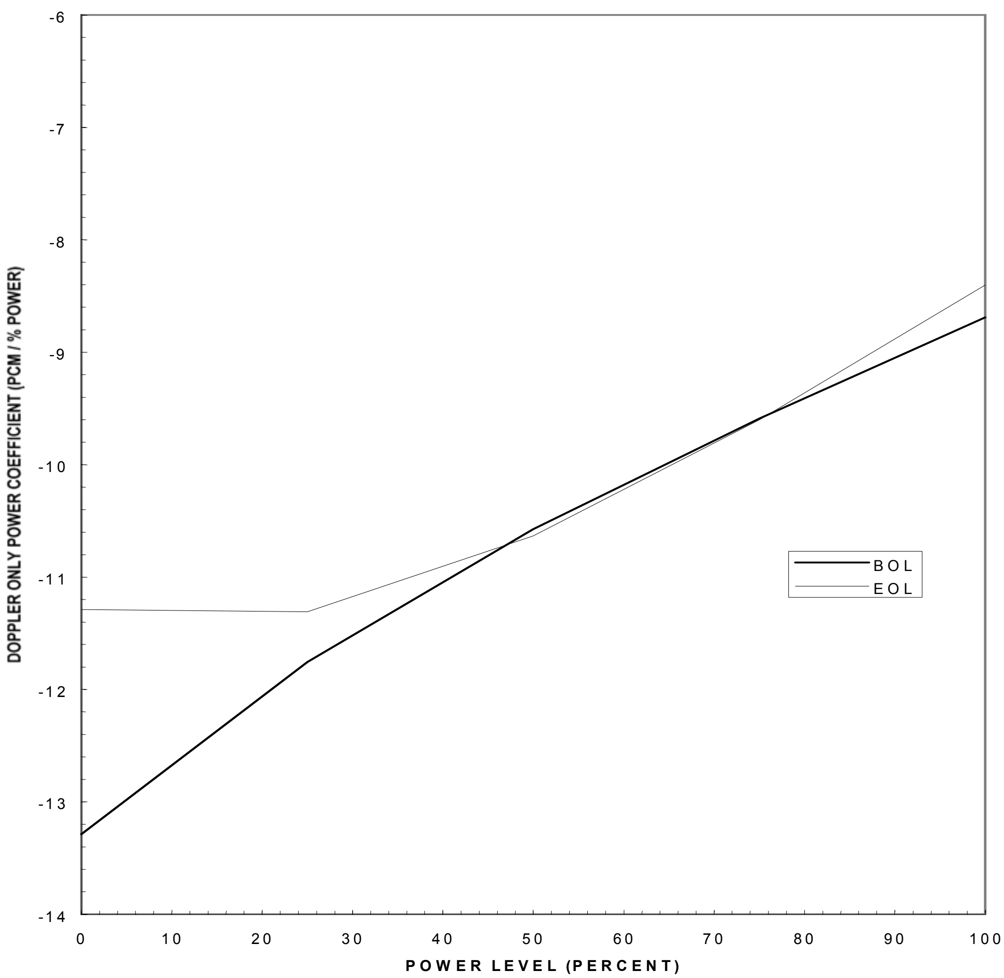


Figure 4.3-19

Typical Doppler-Only Power Coefficient at BOL and EOL

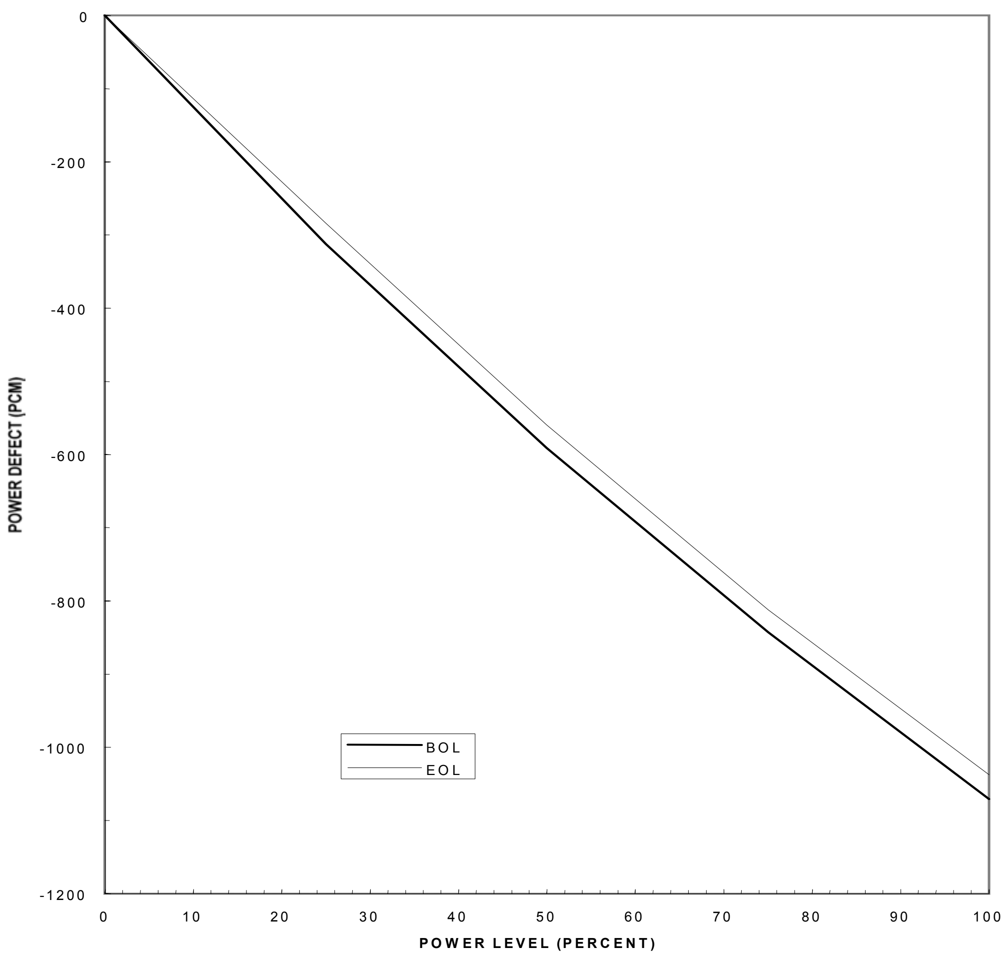


Figure 4.3-20

Typical Doppler-Only Power Defect at BOL and EOL

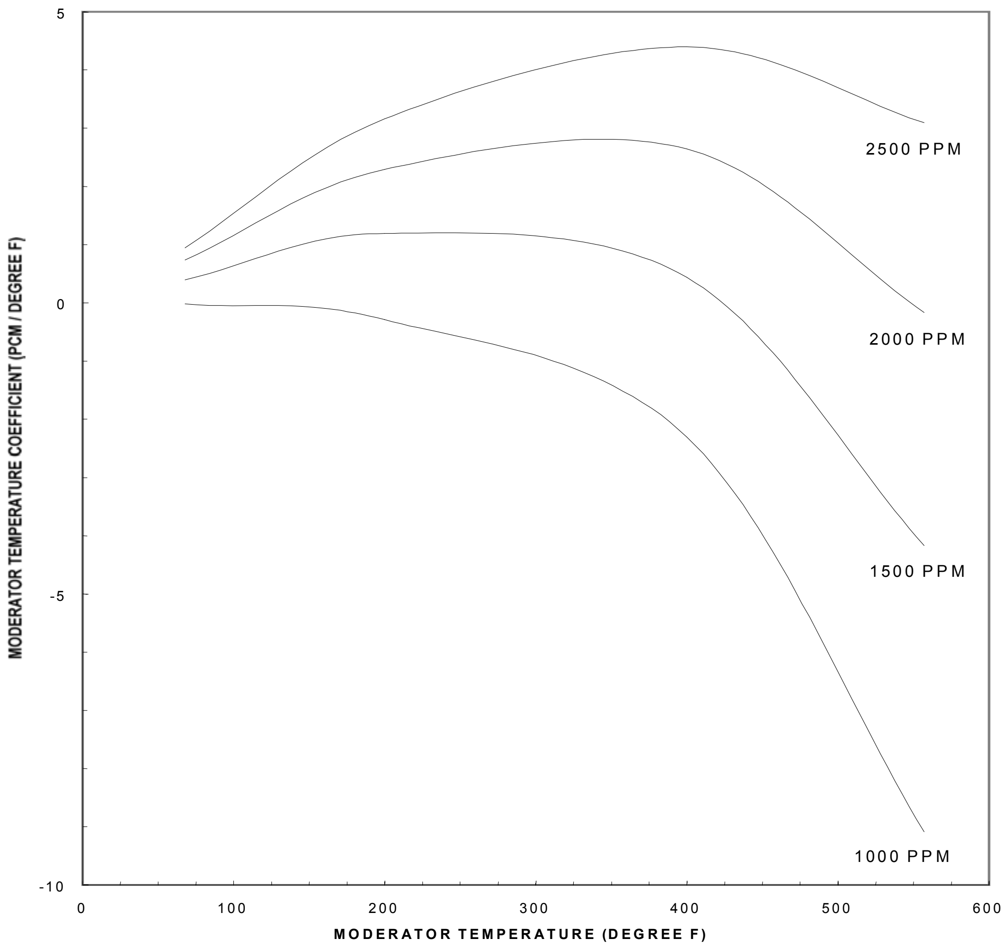


Figure 4.3-21

Typical Moderator Temperature Coefficient at BOL, Unrodded

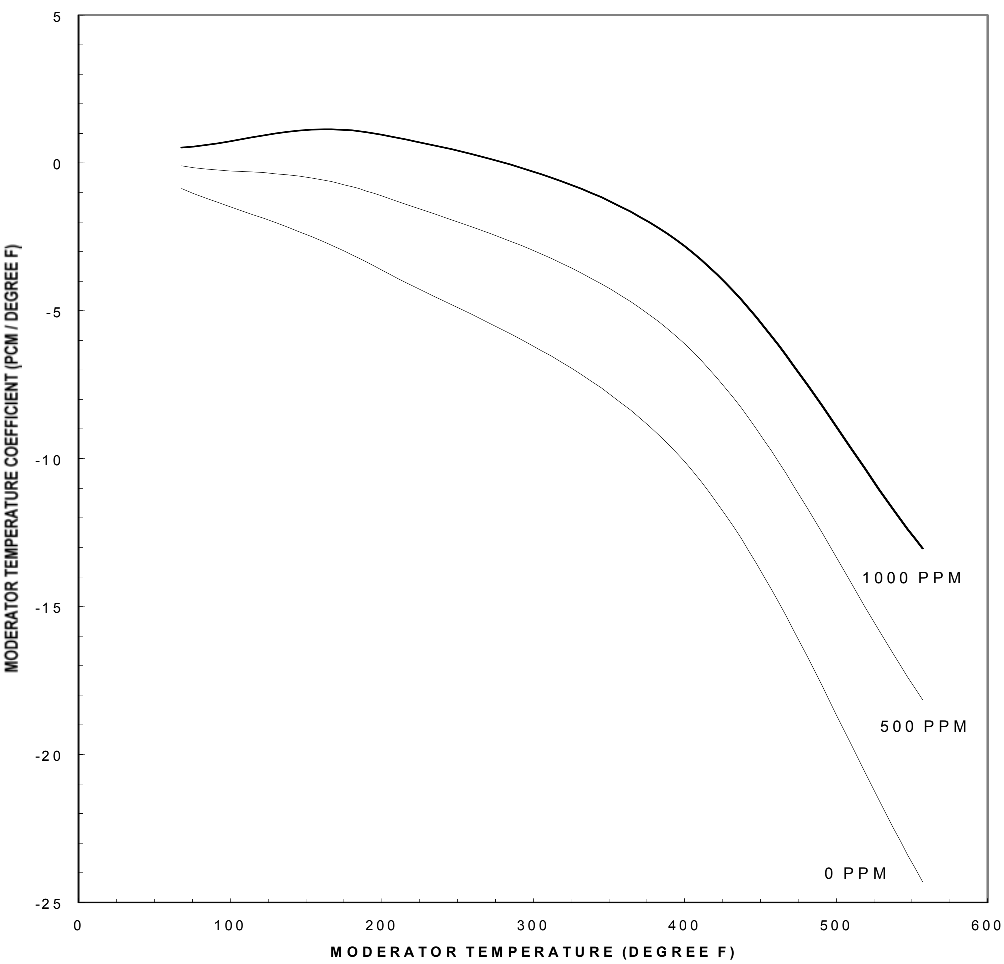


Figure 4.3-22

Typical Moderator Temperature Coefficient at EOL

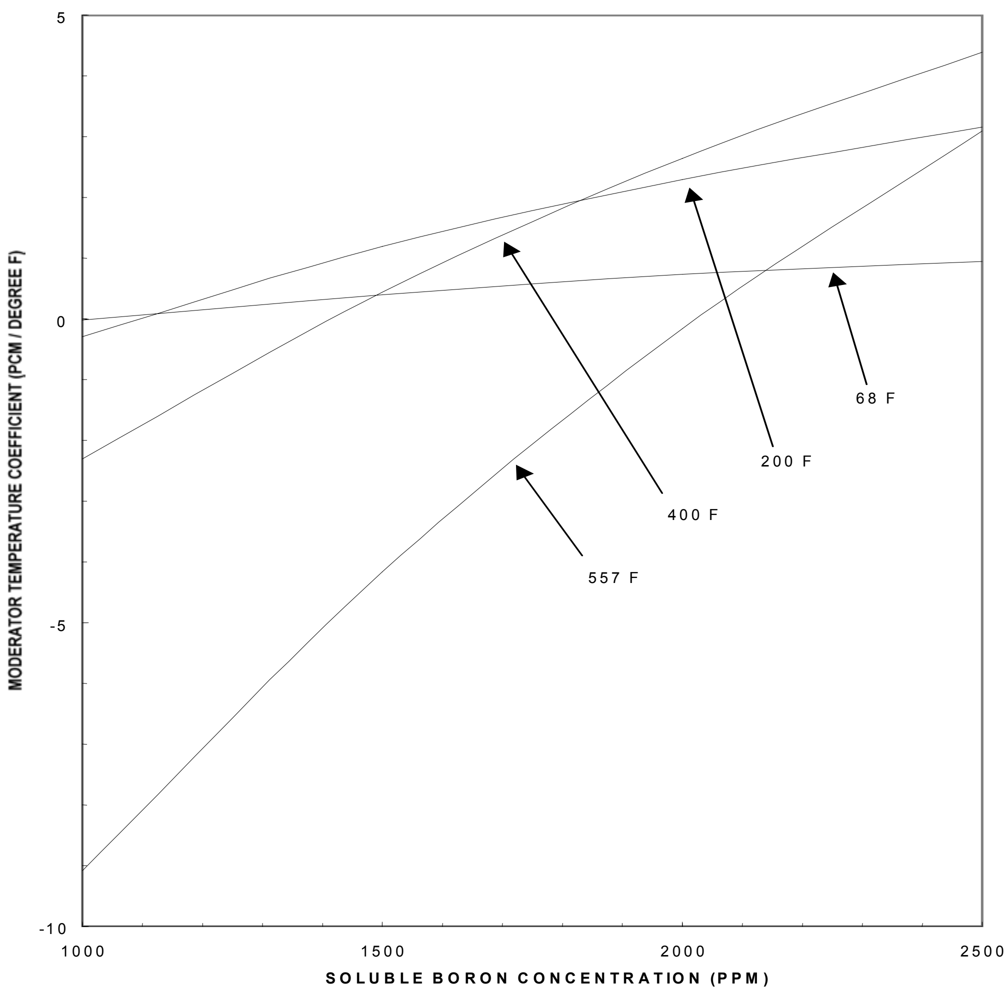


Figure 4.3-23

Typical Moderator Temperature Coefficient as a Function of Boron Concentration at BOL, Unrodded

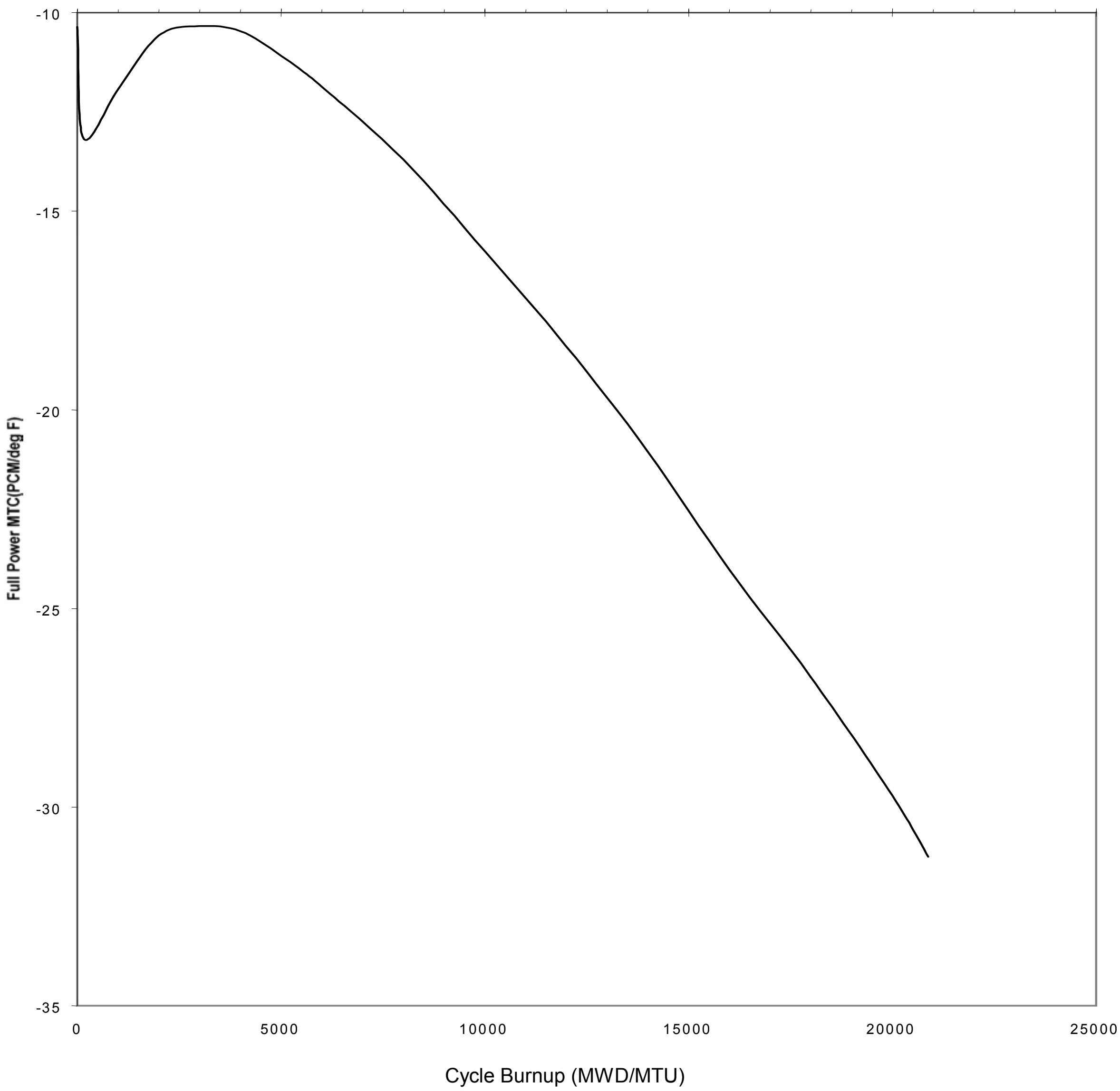


Figure 4.3-24

Typical Hot Full Power Temperature Coefficient versus Cycle Burnup

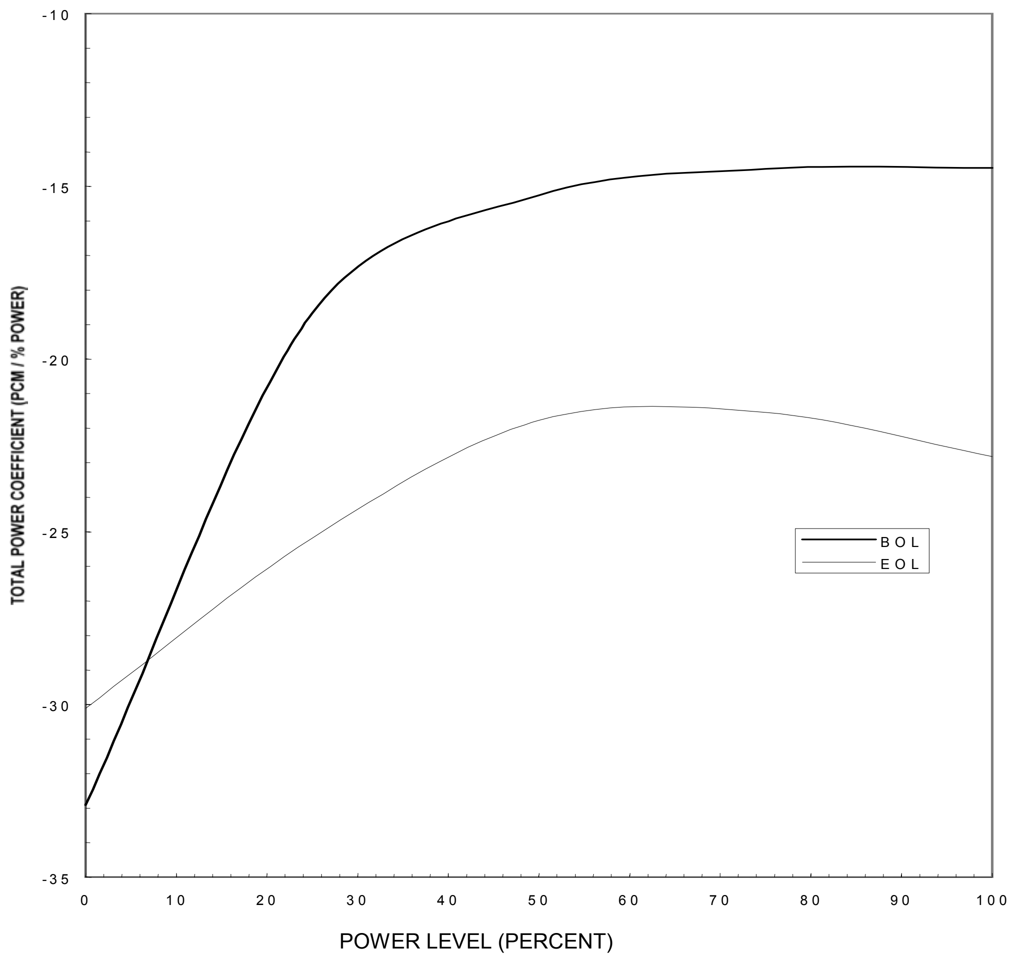


Figure 4.3-25

Typical Total Power Coefficient at BOL and EOL

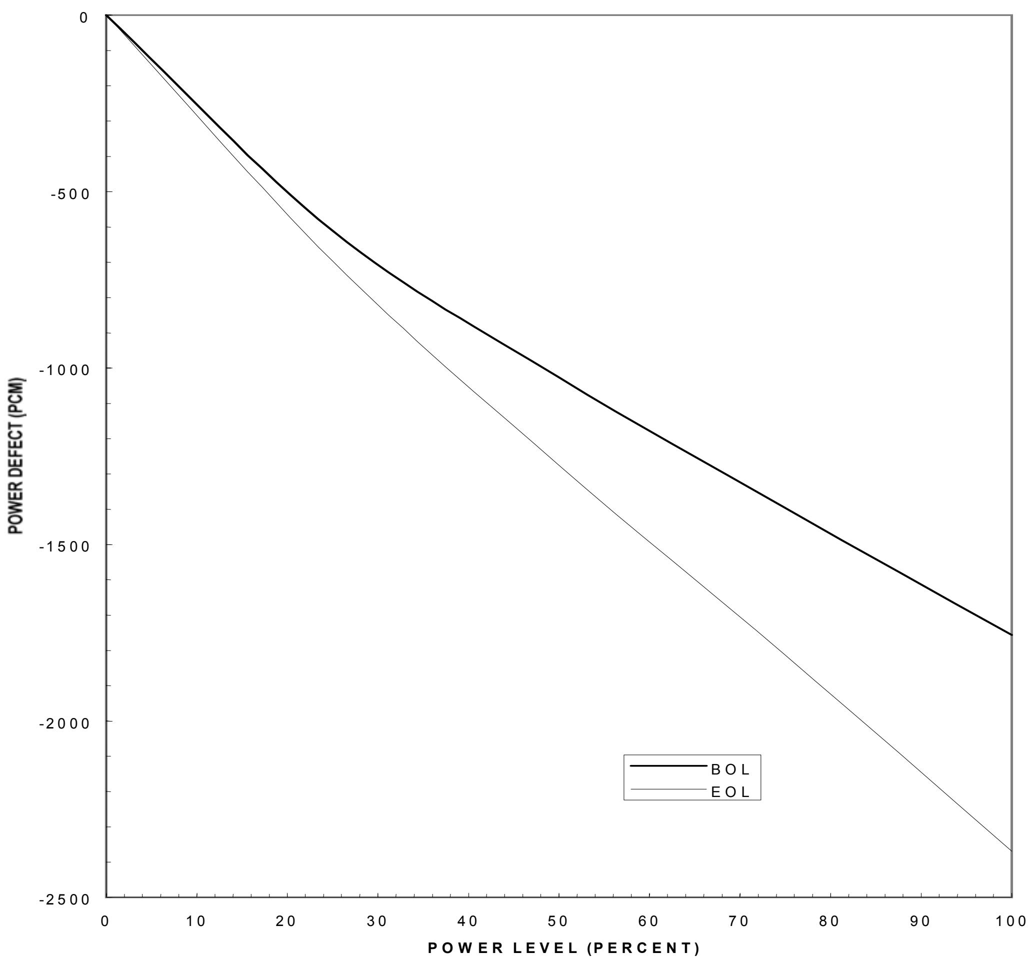


Figure 4.3-26

Typical Total Power Defect at BOL and EOL

180

		R	P	N	M	L	K	J	H	G	F	E	D	C	B	A	
1																	
2							SD4		MC		SD4						
3						M2		SD2		SD2		M2					
4					MB		AO		M1		AO		MB				
5				M2		SD1		SD3		SD3		SD1		M2			
6			SD4		AO		MA		MD		MA		AO		SD4		
7				SD2		SD3		SD1		SD1		SD3		SD2			
8	90		MC		M1		MD		AO		MD		M1		MC		270
9				SD2		SD3		SD1		SD1		SD3		SD2			
10			SD4		AO		MA		MD		MA		AO		SD4		
11				M2		SD1		SD3		SD3		SD1		M2			
12					MB		AO		M1		AO		MB				
13						M2		SD2		SD2		M2					
14							SD4		MC		SD4						
15																	

0

Bank		Number of Clusters
MA	(MSHIM Gray Bank A)	4
MB	(MSHIM Gray Bank B)	4
MC	(MSHIM Gray Bank C)	4
MD	(MSHIM Gray Bank D)	4
M1	(MSHIM Black Bank 1)	4
M2	(MSHIM Black Bank 2)	8
AO	(A.O. Control Bank)	9
SD1	(Shutdown Bank 1)	8
SD2	(Shutdown Bank 2)	8
SD3	(Shutdown Bank 3)	8
SD4	(Shutdown Bank 4)	8
TOTAL		69

Gray Rod Position

Figure 4.3-27

Rod Cluster Control Assembly Pattern

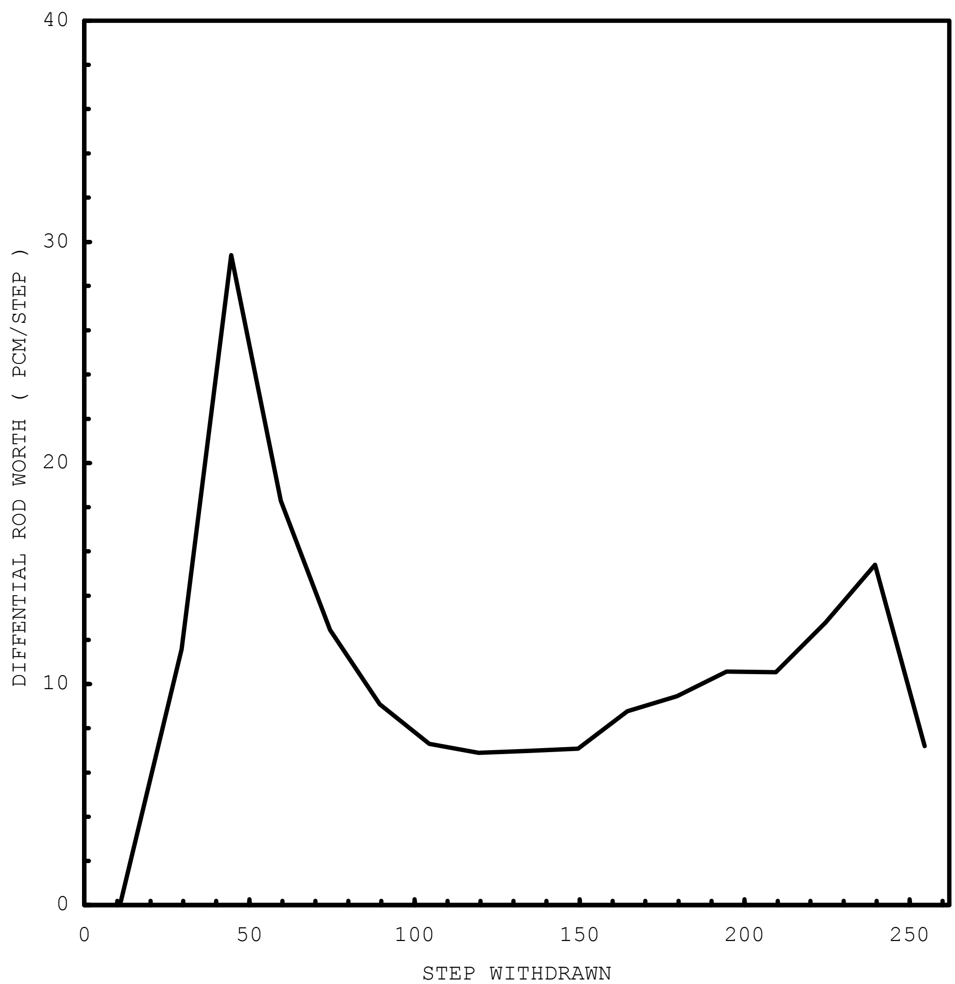


Figure 4.3-28

Typical Accidental Simultaneous Withdrawal of Two Control Banks at EOL, HZP, Moving in the Same Plane

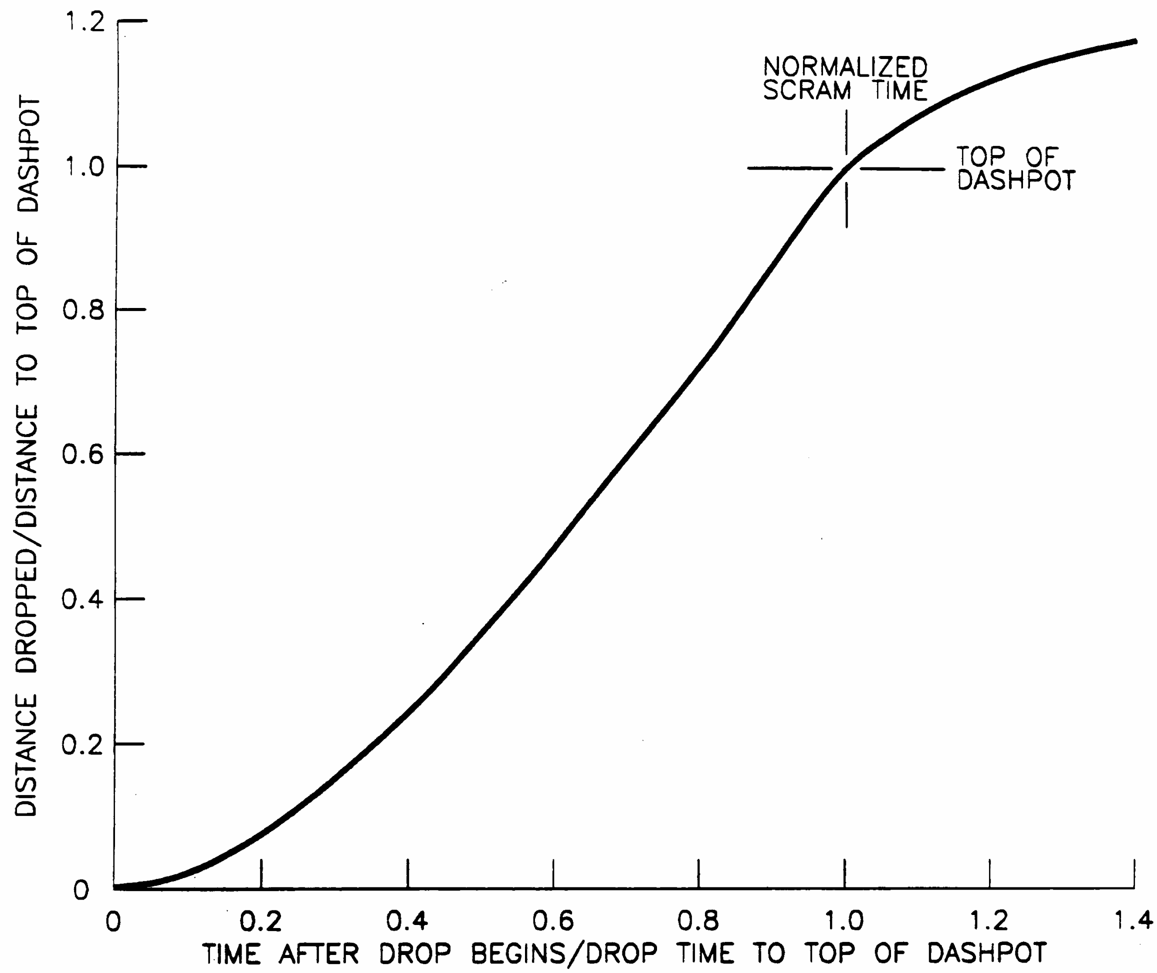


Figure 4.3-29

Typical Design Trip Curve

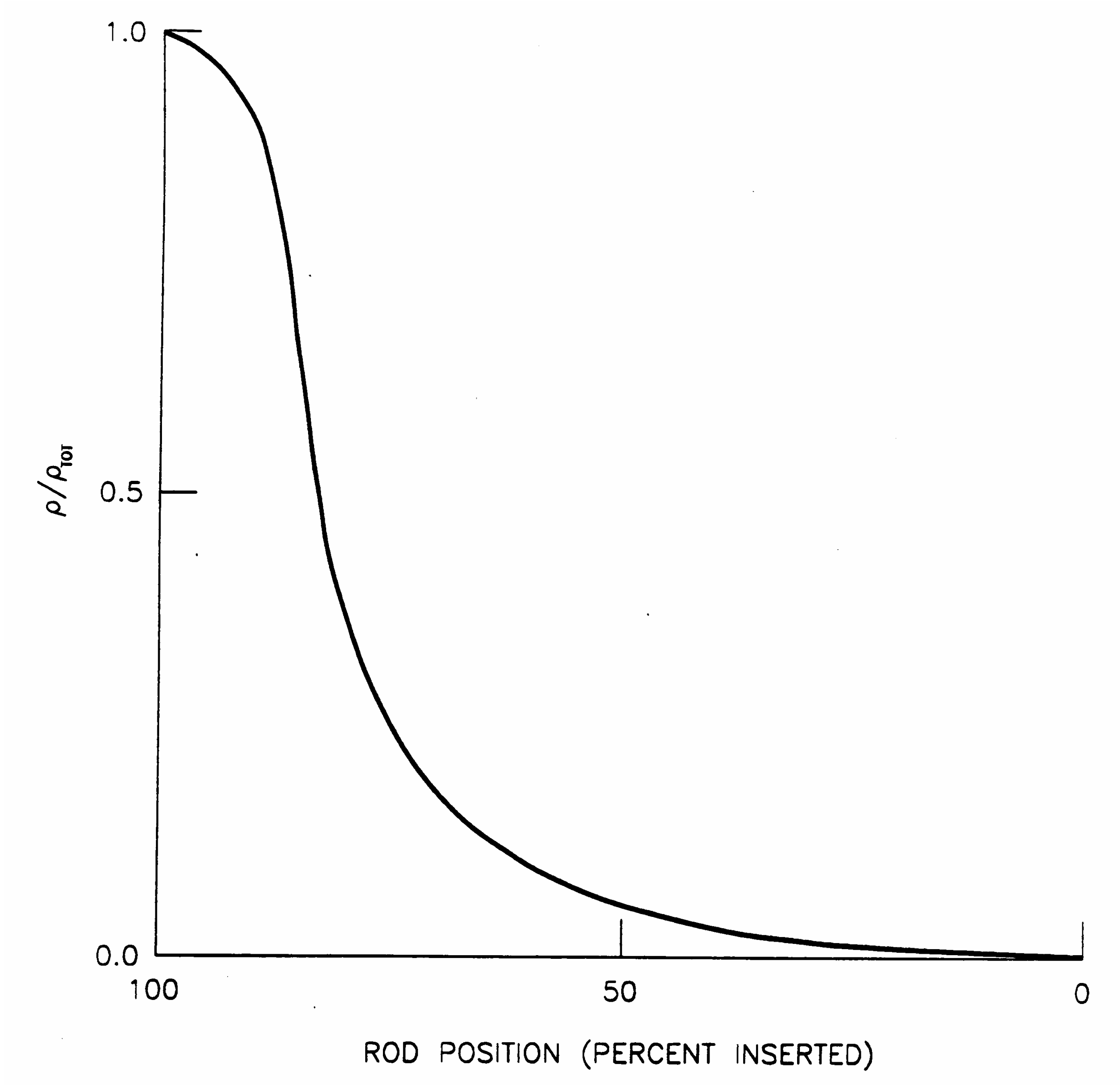


Figure 4.3-30

Typical Normalized Rod Worth Versus Percent Insertion
All Rods Inserting Less Most Reactive Stuck Rod

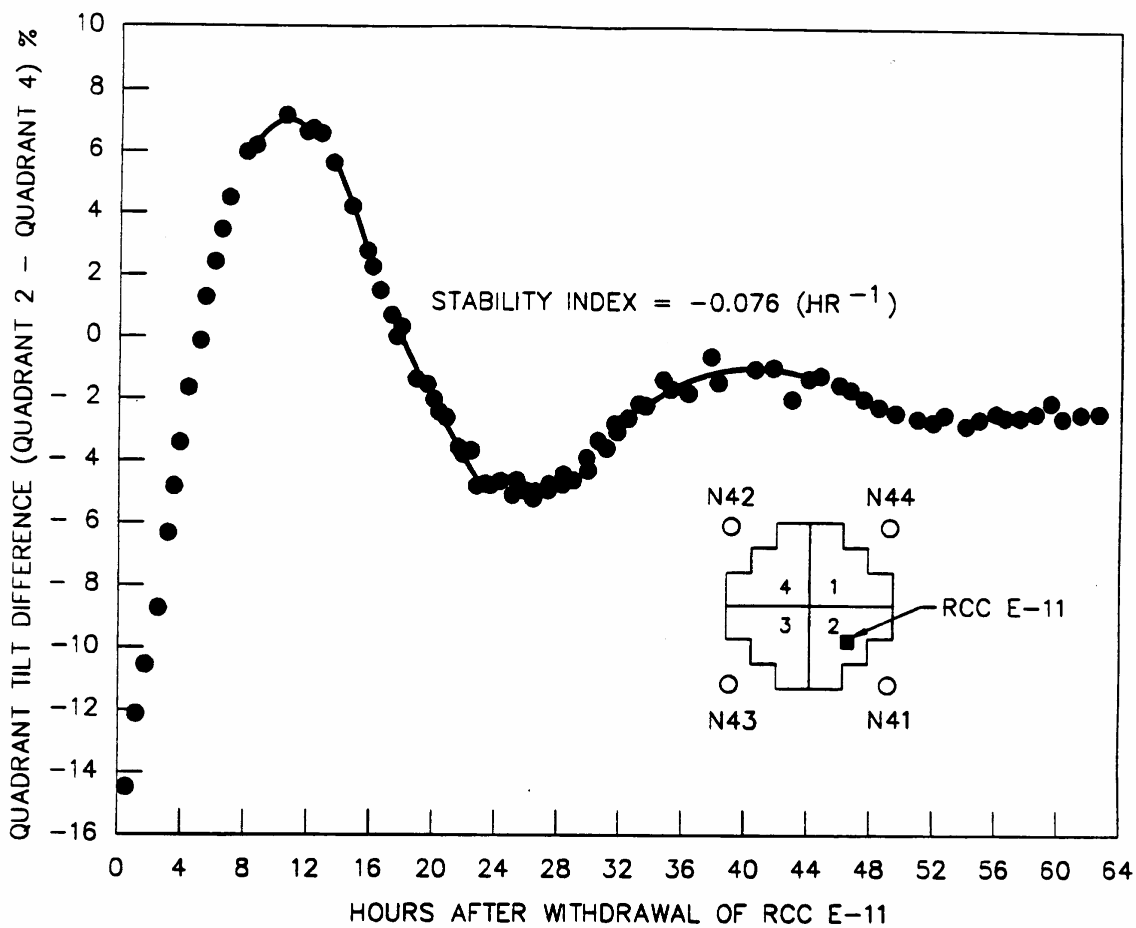


Figure 4.3-31

X-Y Xenon Test Thermocouple Response Quadrant Tilt Difference Versus Time

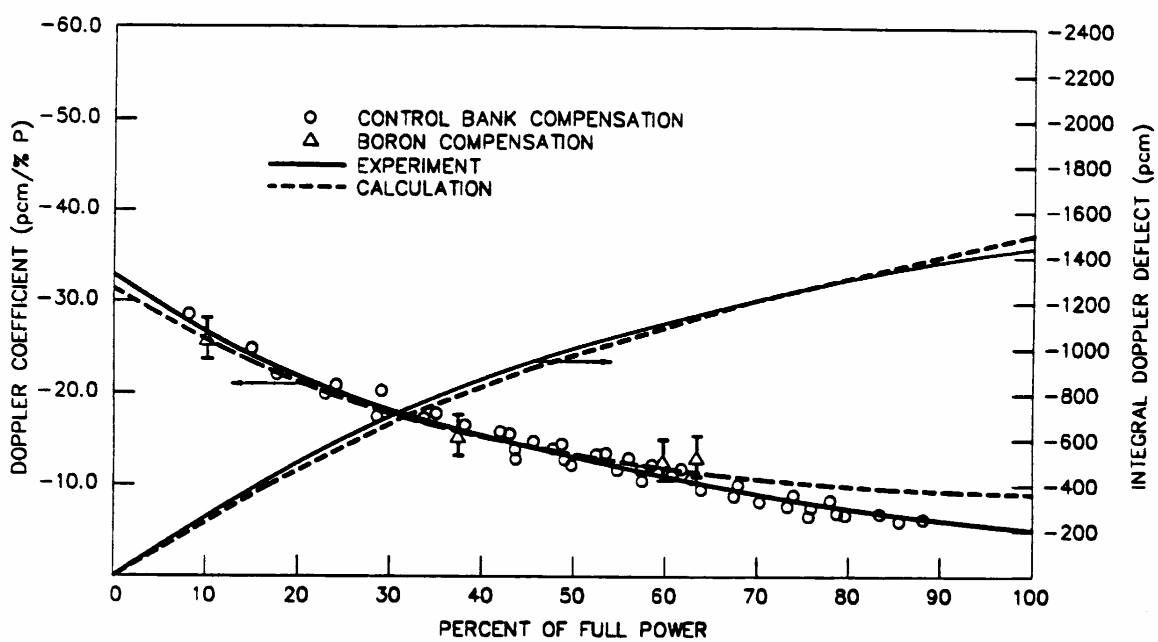


Figure 4.3-32

Calculated and Measured Doppler Defect and Coefficients at BOL, 2-Loop Plant, 121 Assemblies, 12-Foot Core

4.4 Thermal and Hydraulic Design

The thermal and hydraulic design of the reactor core provides adequate heat transfer compatible with the heat generation distribution in the core. This provides adequate heat removal by the reactor coolant system, the normal residual heat removal system, or the passive core cooling system.

4.4.1 Design Basis

The following performance and safety criteria requirements are established for the thermal and hydraulic design of the fuel. Condition I, II, III, and IV transients and events through out this section are as defined in ANSI N18.2a-75 (Reference 1).

- Fuel damage (defined as penetration of the fission product barrier; that is, the fuel rod clad) is not expected during normal operation and operational transients (Condition I) or any transient conditions arising from faults of moderate frequency (Condition II). It is not possible, however, to preclude a very small number of rod failures. These are within the capability of the plant cleanup system and are consistent with the plant design bases.

- The reactor can be brought to a safe state following a Condition III event with only a small fraction of fuel rods damaged (as defined in the above definition), although sufficient fuel damage might occur to preclude resumption of operation without considerable outage time.

- The reactor can be brought to a safe state and the core can be kept subcritical with acceptable heat transfer geometry following transients arising from Condition IV events.

To satisfy these requirements, the following design bases have been established for the thermal and hydraulic design of the reactor core.

4.4.1.1 Departure from Nucleate Boiling Design Basis

4.4.1.1.1 Design Basis

There is at least a 95-percent probability at a 95-percent confidence level that departure from nucleate boiling (DNB) does not occur on the limiting fuel rods during normal operation and operational transients and any transient conditions arising from faults of moderate frequency (Condition I and II events).

4.4.1.1.2 Discussion

The design method employed to meet the DNB design basis for the AP1000 fuel assemblies is the Revised Thermal Design Procedure, WCAP-11397-P-A (Reference 2). With the Revised Thermal Design Procedure methodology, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation predictions are considered statistically to obtain DNB uncertainty factors. Based on the DNB uncertainty factors, Revised Thermal Design Procedure design limits departure from nucleate boiling ratio (DNBR) values are determined such that there is at least a 95-percent probability at a 95-percent confidence level that DNB will not occur on the most limiting fuel rod during normal operation and

operational transients and during transient conditions arising from faults of moderate frequency (Condition I and II events).

Assumed uncertainties in the plant operating parameters (pressurizer pressure, primary coolant temperature, reactor power, and reactor coolant system flow) are evaluated. Only the random portion of the plant operating parameter uncertainties is included in the statistical combination. Instrumentation bias is treated as a direct DNBR penalty. Since the parameter uncertainties are considered in determining the Revised Thermal Design Procedure design limit DNBR values, the plant safety analyses are performed using input parameters at their nominal values.

For those transients that use the VIPRE-01 computer program (subsection 4.4.4.5.2) and the WRB-2M correlation (subsection 4.4.2.2.1), the Revised Thermal Design Procedure design limits are 1.25 for the typical cell and 1.25 for the thimble cell for Core and Axial Offset Limits and 1.22 for the typical cell and 1.21 for the thimble cell for all other RTDP transients. These values may be revised (slightly) when plant specific uncertainties are available.

To maintain DNBR margin to offset DNB penalties such as those due to fuel rod bow (as described in subsection 4.4.2.2.5), the safety analyses are performed to DNBR limits higher than the design limit DNBR values. The difference between the design limit DNBRs and the safety analysis limit DNBRs results in DNBR margin. A portion of this margin is used to offset rod bow and unanticipated DNBR penalties.

The Standard Thermal Design Procedure is used for those analyses where the Revised Thermal Design Procedure is not applicable. In the Standard Thermal Design Procedure method the parameters used in analysis are treated in a conservative way from a DNBR standpoint. The parameter uncertainties are applied directly to the plant safety analyses input values to give the lowest minimum DNBR. The DNBR limit for Standard Thermal Design Procedure is the appropriate DNB correlation limits increased to give sufficient margins to cover any DNBR penalties associated with the analysis.

By preventing DNB, adequate heat transfer is provided from the fuel clad to the reactor coolant, thereby preventing clad damage as a result of inadequate cooling. Maximum fuel rod surface temperature is not a design basis, since it is within a few degrees of coolant temperature during operation in the nucleate boiling region. Limits provided by the nuclear control and protection systems are such that this design basis is met for transients associated with Condition II events including overpower transients. There is an additional large DNBR margin at rated power operation and during normal operating transients.

4.4.1.2 Fuel Temperature Design Basis

4.4.1.2.1 Design Basis

During modes of operation associated with Condition I and Condition II events, there is at least a 95-percent probability at a 95-percent confidence level that the peak kW/ft fuel rods will not exceed the uranium dioxide melting temperature. The melting temperature of uranium dioxide is 5080°F (Reference 3) unirradiated and decreasing 58°F per 10,000 MWD/MTU. By precluding uranium dioxide melting, the fuel geometry is preserved and possible adverse effects of molten uranium dioxide on the cladding are eliminated. Design evaluations for Condition I and II events

have shown that fuel melting will not occur for achievable local burnups up to 75,000 MWD/MTU (Reference 81). The NRC has approved design evaluations up to 60,000 MWD/MTU in Reference 81 and up to 62,000 MWD/MTU in Reference 9.

4.4.1.2.2 Discussion

Fuel rod thermal evaluations are performed at rated power, at maximum overpower, and during transients at various burnups. These analyses confirm that this design basis and the fuel integrity design bases given in Section 4.2 are met. They also provide input for the evaluation of Condition III and IV events given in Chapter 15.

The center-line temperature limit has been applied to reload cores with a lead rod average burnup of up to 60,000 MWD/MTU. For higher burnups, the peak kilowatt-per-foot experienced during Condition I and II events is limited to that maximum value which is sufficient to provide that the fuel center-line temperatures remain below the melting temperature for the fuel rods. Thus, the fuel rod design basis that fuel rod damage not occur due to fuel melting continues to be met.

4.4.1.3 Core Flow Design Basis

4.4.1.3.1 Design Basis

Typical minimum value of 94.1 percent of the thermal flow rate is assumed to pass through the fuel rod region of the core and is effective for fuel rod cooling. Coolant flow through the thimble tubes and the leakage from the core barrel-shroud region into the core is not considered effective for heat removal.

4.4.1.3.2 Discussion

Core cooling evaluations are based on the thermal flow rate (minimum flow) entering the reactor vessel. A typical maximum value of 5.9 percent of this value is allotted as bypass flow. This includes rod cluster control guide thimble cooling flow, head cooling flow, shroud cavity bypass flow and leakage to the vessel outlet nozzle.

The maximum bypass flow fraction of 5.9 percent assumes the use of thimble plugging devices in the rod cluster control guide thimble tubes that do not contain any other core components.

4.4.1.4 Hydrodynamic Stability Design Basis

Modes of operation associated with Condition I and II events do not lead to hydrodynamic instability.

4.4.1.5 Other Considerations

The design bases described in subsections 4.4.1 through 4.4.1.4 together with the fuel clad and fuel assembly design bases given in subsection 4.2.1 are sufficiently comprehensive that additional limits are not required.

Fuel rod diametral gap characteristics, moderator coolant flow velocity and distribution, and moderator void are not inherently limiting. Each of these parameters is incorporated into the thermal and hydraulic models used to confirm that the above-mentioned design criteria are met. For instance, the fuel rod diametral gap characteristics change with time, as described in subsection 4.2.3, and the fuel rod integrity is evaluated on that basis. The effect of the moderator flow velocity and distribution described in subsection 4.4.2.2 and the moderator void distribution described in subsection 4.4.2.4 are included in the core thermal evaluation and thus affect the design basis.

Meeting the fuel clad integrity criteria covers the possible effects of clad temperature limitations. Clad surface temperature limits are imposed on Condition I and Condition II operation to preclude conditions of accelerated oxidation. A clad temperature limit is applied to the loss-of-coolant accident described in subsection 15.6.5; control rod ejection accident described in subsection 15.4.8; and locked rotor accident described in subsection 15.3.3.

4.4.2 Description of Thermal and Hydraulic Design of the Reactor Core

4.4.2.1 Summary Comparison

Table 4.4-1 provides a comparison of the design parameters for the AP1000, the AP600, and a licensed Westinghouse-designed plant using XL Robust fuel. For the comparison with a plant containing XL Robust fuel, a 193 fuel assembly plant is used, since no domestic Westinghouse designed 157 fuel assembly plants use 17x17 fuel XL Robust fuel.

4.4.2.2 Critical Heat Flux Ratio or DNBR and Mixing Technology

The minimum DNBRs for the rated power and anticipated transient conditions are given in Table 4.4-1. The minimum DNBR in the limiting flow channel is typically downstream of the peak heat flux location (hotspot) due to the increased downstream enthalpy rise.

DNBRs are calculated by using the correlation and definitions described in subsections 4.4.2.2.1 and 4.4.2.2.2. The VIPRE-01 computer code described in subsection 4.4.4.5, is used to determine the flow distribution in the core and the local conditions in the hot channel for use in the DNB correlation. The use of hot channel factors is described in subsections 4.4.4.3.1 (nuclear hot channel factors) and 4.4.2.2.4 (engineering hot channel factors).

4.4.2.2.1 DNB Technology

The primary DNB correlation used for the analysis of the AP1000 fuel is the WRB-2M correlation (Reference 82). The WRB-2M correlation applies to the Robust Fuel Assemblies, which are planned to be used in the AP1000 core. This correlation applies to most AP1000 conditions.

A correlation limit of 1.14 is applicable for the WRB-2M correlation.

The applicable range of parameters for the WRB-2M correlation is:

Pressure	$1495 \leq P \leq 2425$ psia
Local mass velocity	$0.97 \leq G_{loc}/10^6 \leq 3.1$ lb/ft^2-hr
Local quality	$-0.1 \leq X_{loc} \leq 0.29$
Heated length, inlet to CHF location	$L_H \leq 14$ feet
Grid spacing	$10 \leq g_{sp} \leq 20.6$ inches
Equivalent hydraulic diameter	$0.37 \leq D_e \leq 0.46$ inches
Equivalent heated hydraulic diameter	$0.46 \leq D_h \leq 0.54$ inches

The WRB-2 (Reference 4) or W-3 (References 5 and 6) correlation is used wherever the WRB-2M correlation is not applicable. The WRB-2 correlation limit is 1.17.

The applicable range of parameters for the WRB-2 correlation is:

Pressure	$1440 \leq P \leq 2490$ psia
Local mass velocity	$0.9 \leq G_{loc}/10^6 \leq 3.7$ lb/ft^2-hr
Local quality	$-0.1 \leq X_{loc} \leq 0.3$
Heat length, inlet to DNB location	$L_h \leq 14$ feet
Grid spacing	$10 \leq g_{sp} \leq 26$ inches
Equivalent hydraulic diameter	$0.37 \leq D_e \leq 0.51$ inches
Equivalent heated hydraulic diameter	$0.46 \leq D_h \leq 0.59$ inches

The WRB-2 correlation was developed based on mixing vane data and, therefore, is only applicable in the heated rod spans above the first mixing vane grid.

In the heated region below the first mixing vane grid the W-3 correlation (see References 5 and 6), which does not take credit for mixing vane grids, is used to calculate DNBR values. In addition, the W-3 correlation is applied in the analysis of accident conditions where the system pressure is below the range of the primary correlation. For system pressures in the range of 500 to 1000 psia, the W-3 correlation limit is 1.45 (Reference 7). For system pressures greater than 1000 psia, the W-3 correlation limit is 1.30. The pressures associated with some of the steamline break statepoints are in the range of 300 to 500 psia. Using additional information, the W-3 correlation is shown to be applicable with these pressures and a correlation limit of 1.45.

A cold wall factor, described in WCAP-7695-L (Reference 8), is applied to the W-3 DNB correlation to conservatively account for the presence of the unheated thimble surfaces.

4.4.2.2.2 Definition of DNBR

The DNB heat flux ratio, DNBR, as applied to typical cells (flow cells with all walls heated) and thimble cells (flow cells with heated and unheated walls) is defined as:

$$\mathrm{DNBR} = \frac{q''_{\mathrm{DNB,\ predicted}}}{q''_{\mathrm{actual}}}$$

where:

$$q''_{DNB,\ predicted} = \frac{q''_{WRB-2M}}{F} \text{ or } q''_{DNB,\ predicted} = \frac{q''_{WRB-2}}{F}$$

q''_{WRB-2M} = the uniform DNB heat flux as predicted by the WRB-2M DNB correlation

q''_{WRB-2} = the uniform DNB heat flux as predicted by the WRB-2 DNB correlation

F = the flux shape factor to account for nonuniform axial heat flux distributions (Reference 10) with the term "C" modified as in Reference 5

q''actual = the actual local heat flux

The DNBR as applied to the W-3 DNB correlation is:

$$DNBR = \frac{q''_{predicted}}{q''_{actual}}$$

where:

$$q''_{predicted} = \frac{q''_{EU-W-3} \text{ x } CWF}{F}$$

q''_{EU-W-3} = the uniform DNB heat flux as predicted by the W-3 DNB correlation (Reference 5)

$$CWF = 1.0\text{-}Ru\ [T]$$

where:

$$T = 13.76 - 1.372e^{1.78x} - 4.732\ \left(\frac{G}{10^6}\right)^{-0.0535} - 0.0619\ \left(\frac{P}{1000}\right)^{0.14} - 8.509\, D_h^{0.017}$$

$Ru = 1\text{-}D_e/D_h$

If the cold wall factor is used (thimble cell), D_h is used in evaluating q''_{EU-W-3}. If the CWF is not used (typical cells), set CWF = 1.0.

4.4.2.2.3 Mixing Technology

The rate of heat exchange by mixing between flow channels is proportional to the difference in the local mean fluid enthalpy of the respective channels, the local fluid density, and the flow velocity. The proportionality is expressed by the dimensionless thermal diffusion coefficient (TDC) which is defined as:

$$TDC = \frac{w'}{\rho\,Va}$$

where:

w' = flow exchange rate per unit length (lbm/ft.-s)
ρ = fluid density (lbm/ft.^{3})
V = fluid velocity (ft./s)
a = lateral flow area between channels per unit length (ft.^{2}/ft.)

The application of the thermal diffusion coefficient in the VIPRE-01 analysis for determining the overall mixing effect or heat exchange rate is presented in Reference 83.

As discussed in WCAP-7941-P-A (Reference 12) those series of tests, using the "R" mixing vane grid design on 13-, 26-, and 32-inch grid spacing, were conducted in pressurized water loops at Reynolds numbers similar to that of a pressurized water reactor core under the following single- and two-phase (subcooled boiling) flow conditions:

• Pressure	1500 to 2400 psia
• Inlet temperature	332 to 642°F
• Mass velocity	1.0 to 3.5 x 10^6 lbm/hr-ft.^{2}
• Reynolds number	1.34 to 7.45 x 10^5
• Bulk outlet quality	-52.1 to -13.5 percent

The thermal diffusion coefficient is determined by comparing the THINC code predictions with the measured subchannel exit temperatures. Data for 26-inch axial grid spacing are presented in Figure 4.4-1, where the thermal diffusion coefficient is plotted versus the Reynolds number. The thermal diffusion coefficient is found to be independent of the Reynolds number, mass velocity, pressure, and quality over the ranges tested. The two-phase data (local, subcooled boiling) falls within the scatter of the single-phase data. The effect of two-phase flow on the value of the thermal diffusion coefficient is demonstrated in WCAP-7941-P-A (Reference 12), by Rowe and Angle (References 13 and 14), and Gonzalez-Santalo and Griffith (Reference 15). In the subcooled boiling region, the values of the thermal diffusion coefficient are indistinguishable from the single-phase values. In the quality region, Rowe and Angle show that in the case with rod spacing similar to that in pressurized water reactor core geometry, the value of the thermal diffusion coefficient increased with quality to a point and then decreased, but never below the single-phase value. Gonzalez-Santalo and Griffith show that the mixing coefficient increased as the void fraction increased.

The data from these tests on the R-mixing vane grid show that a design thermal diffusion coefficient value of 0.038 (for 26-inch grid spacing) can be used in determining the effect of coolant mixing in the THINC analysis. An equivalent value of the mixing coefficient is used in the VIPRE-01 evaluations (Reference 83). A mixing test program similar to the one just described was conducted for the current 17 x 17 geometry and mixing vane grids on 26-inch spacing, as described in WCAP-8298-P-A (Reference 16). The mean value of the thermal diffusion coefficient obtained from these tests is 0.059.

The inclusion of intermediate flow mixer grids in the upper spans of the fuel assembly results in a grid spacing of approximately 10 inches giving higher values of the thermal diffusion coefficient. A conservative value of the thermal diffusion coefficient, .038, is used to determine the effect of coolant mixing in the core thermal performance analysis.

4.4.2.2.4 Hot Channel Factors

The total hot channel factors for heat flux and enthalpy rise are defined as the maximum-to-core-average ratios of these quantities. The heat flux hot channel factor considers the local maximum linear heat generation rate at a point (the hotspot), and the enthalpy rise hot channel factor involves the maximum integrated value along a channel (the hot channel).

Each of the total hot channel factors is composed of a nuclear hot channel factor, subsection 4.4.4.3, describing the neutron power distribution and an engineering hot channel factor, which allows for variations in flow conditions and fabrication tolerances. The engineering hot channel factors are made up of subfactors which account for the influence of the variations of fuel pellet diameter, density, enrichment, and eccentricity; inlet flow distribution; flow redistribution; and flow mixing.

Heat Flux Engineering Hot Channel Factor, F_Q^E

The heat flux engineering hot channel factor is used to evaluate the maximum linear heat generation rate in the core. This subfactor is determined by statistically combining the fabrication variations for fuel pellet diameter, density, and enrichment. As shown in WCAP-8174 (Reference 17), no DNB penalty need be taken for the short, relatively low-intensity heat flux spikes caused by variations in the above parameters, as well as fuel pellet eccentricity and fuel rod diameter variation.

Enthalpy Rise Engineering Hot Channel Factor, $F_{\Delta H}^E$

The effect of variations in flow conditions and fabrication tolerances on the hot channel enthalpy rise is directly considered in the VIPRE-01 core thermal subchannel analysis, described in subsection 4.4.4.5.1 under any reactor opening condition. The following items are considered as contributors to the enthalpy rise engineering hot channel factor:

- Pellet diameter, density, and enrichment

  Variations in pellet diameter, density, and enrichment are considered statistically in establishing the limit DNBRs, described in subsection 4.4.1.1.2, for the Revised Thermal

Design Procedure (Reference 2). Uncertainties in these variables are determined from sampling of manufacturing data.

- Inlet flow maldistribution

  The consideration of inlet flow maldistribution in core thermal performances is described in subsection 4.4.4.2.2. A design basis of five-percent reduction in coolant flow to the hot assembly is used in the VIPRE-01 analyses.

- Flow redistribution

  The flow redistribution accounts for the reduction in flow in the hot channel resulting from the high flow resistance in the channel due to the local or bulk boiling. The effect of the nonuniform power distribution is inherently considered in the VIPRE-01 analyses for every operating condition evaluated.

- Flow mixing

  The subchannel mixing model incorporated in the VIPRE-01 code and used in reactor design is based on experimental data, as detailed in WCAP-7667-P-A (Reference 18) and discussed in subsections 4.4.2.2.3 and 4.4.4.5.1. The mixing vanes incorporated in the spacer grid design induce additional flow mixing between the various flow channels in a fuel assembly as well as between adjacent assemblies. This mixing reduces the enthalpy rise in the hot channel resulting from local power peaking or unfavorable mechanical tolerances. The VIPRE-01 mixing model is discussed in Reference 83.

4.4.2.2.5 Effects of Rod Bow on DNBR

The phenomenon of fuel rod bowing, as described in WCAP-8691 (Reference 19), is accounted for in the DNBR safety analysis of Condition I and Condition II events for each plant application. Applicable generic credits for margin resulting from retained conservatism in the evaluation of DNBR and/or margin obtained form measured plant operating parameters (such as $F^N_{\Delta H}$ or core flow), which are less limiting than those required by the plant safety analysis, can be used to offset the effect of rod bow.

For the safety analysis of the AP1000, sufficient DNBR margin was maintained, as described in subsection 4.4.1.1.2, to accommodate the full and low flow rod bow DNBR penalties identified in Reference 20. The referenced penalties are applicable to the analyses using the WRB-2M or WRB-2 DNB correlations.

The maximum rod bow penalties (less than 1.5 percent DNBR) accounted for in the design safety analysis are based on an assembly average burnup of 24,000 MWD/MTU. At burnups greater than 24,000 MWD/MTU, credit is taken for the effect of $F^N_{\Delta H}$ burndown, due to the decrease in fissionable isotopes and the buildup of fission product inventory, and no additional rod bow penalty is required (Reference 21).

In the upper spans of the fuel assembly, additional restraint is provided with the intermediate flow mixer grids such that the grid-to-grid spacing in those spans with intermediate flow mixer grids is approximately 10 inches compared to approximately 20 inches in the other spans. Using the NRC approved scaling factor [see WCAP 8691 (Reference 19) and Reference 21], results in predicted channel closure in the limiting 10 inch spans of less than 50 percent closure. Therefore, no rod bow DNBR penalty is required in the 10 inch spans in the safety analyses.

4.4.2.3 Linear Heat Generation Rate

The core average and maximum linear heat generation rates are given in Table 4.4-1. The method of determining the maximum linear heat generation rate is given in subsection 4.3.2.2.

4.4.2.4 Void Fraction Distribution

The calculated core average and the hot subchannel maximum and average void fractions are presented in Table 4.4-2 for operation at full power. The void models used in the VIPRE-W code are described in subsection 4.4.2.7.3.

4.4.2.5 Core Coolant Flow Distribution

The VIPRE-01 code is used to calculate the flow and enthalpy distribution in the core for use in safety analysis. Extensive experimental verification of VIPRE-01 is presented in Reference 84.

4.4.2.6 Core Pressure Drops and Hydraulic Loads

4.4.2.6.1 Core Pressure Drops

The analytical model and experimental data used to calculate the pressure drops shown in Table 4.4-1 are described in subsection 4.4.2.7. The core pressure drop includes the fuel assembly, lower core plate, and upper core plate pressure drops. The full-power operation pressure drop values shown in Table 4.4-1 are the unrecoverable pressure drops across the vessel, including the inlet and outlet nozzles, and across the core. These pressure drops are based on the best-estimate flow for actual plant operating conditions as described in subsection 5.1.4. This subsection also defines and describes the thermal design flow (minimum flow) that is the basis for reactor core thermal performance and the mechanical design flow (maximum flow) that is used in the mechanical design of the reactor vessel internals and fuel assemblies. Since the best-estimate flow is that flow which is most likely to exist in an operating plant, the calculated core pressure drops in Table 4.4-1 are based on this best-estimate flow rather than the thermal design flow.

The uncertainties associated with the core pressure drop values are presented in subsection 4.4.2.9.2.

4.4.2.6.2 Hydraulic Loads

Figure 4.2-2 shows the fuel assembly hold-down springs. These springs are designed to keep the fuel assemblies in contact with the lower core plate under Condition I and II events, except for the turbine overspeed transient associated with a loss of external load. The hold-down springs are designed to tolerate the possibility of an overdeflection associated with fuel assembly lift-off for this case and to provide contact between the fuel assembly and the lower core plate following this

transient. More adverse flow conditions occur during a loss-of-coolant accident. These conditions are presented in subsection 15.6.5.

Hydraulic loads at normal operating conditions are calculated considering the mechanical design flow, described in Section 5.1, and accounting for the minimum core bypass flow based on manufacturing tolerances. Core hydraulic loads at cold plant startup conditions are based on the cold mechanical design flow, but are adjusted to account for the coolant density difference. Conservative core hydraulic loads for a pump overspeed transient, which could possibly create a flow rate 18-percent greater than the best estimate flow, are evaluated to be approximately twice the fuel assembly weight.

Hydraulic verification tests for the fuel assembly are described in Reference 86.

4.4.2.7 Correlation and Physical Data

4.4.2.7.1 Surface Heat Transfer Coefficients

Forced convection heat transfer coefficients are obtained from the Dittus-Boelter correlation (Reference 24), with the properties evaluated at bulk fluid conditions:

$$\frac{hD_c}{K} = 0.023 \frac{D_c G}{\mu}^{0.9} \frac{C_\rho \mu}{K}^{0.4}$$

where:

h	=	heat transfer coefficient (btu/h-ft^2-°F)
D_e	=	equivalent diameter (ft)
K	=	thermal conductivity (Btu/h-ft-°F)
G	=	mass velocity (lbm/h-ft^2)
μ	=	dynamic viscosity (lbm/ft-h)
C_p	=	heat capacity (Btu/lb-°F)

This correlation has been shown to be conservative (Reference 25) for rod bundle geometries with pitch-to-diameter ratios in the range used by pressurized water reactors.

The onset of nucleate boiling occurs when the clad wall temperature reaches the amount of superheat predicted by Thom's correlation (Reference 26). After this occurrence, the outer clad wall temperature is determined by:

$$\Delta T_{sat} = [0.072\exp(-P/1260)](q'')^{0.5}$$

where:

ΔT_{sat}	=	wall superheat, T_W - T_{sat} (°F)
q''	=	wall heat flux (Btu/h-ft^2)
P	=	pressure (psia)
T_w	=	outer clad wall temperature (°F)
T_{sat}	=	saturation temperature of coolant at pressure P (°F)

4.4.2.7.2 Total Core and Vessel Pressure Drop

Unrecoverable pressure losses occur as a result of viscous drag (friction) and/or geometry changes (form) in the fluid flow path. The flow field is assumed to be incompressible, turbulent, single-phase water. Those assumptions apply to the core and vessel pressure drop calculations for the purpose of establishing the primary loop flow rate. Two-phase considerations are neglected in the vessel pressure drop evaluation because the core average void is negligible, as shown in Table 4.4-2. Two-phase flow considerations in the core thermal subchannel analysis are considered and the models are described in subsection 4.4.4.2.3. Core and vessel pressure losses are calculated by equations of the form:

$$\Delta P_L = (K + f \frac{L}{D_c}) \frac{\rho V^2}{2 g_c (144)}$$

where:

ΔP_L = unrecoverable pressure drop (lb/in.^{2})
ρ = fluid density (lbm/ft^3)
L = length (ft)
D_e = equivalent diameter (ft)
V = fluid velocity (ft/s)
g_c = 32.174 (lbm-ft/lb p-s^2)
K = form loss coefficient (dimensionless)
f = friction loss coefficient (dimensionless)

Fluid density is assumed to be constant at the appropriate value for each component in the core and vessel. Because of the complex core and vessel flow geometry, precise analytical values for the form and friction loss coefficients are not available. Therefore, experimental values for these coefficients are obtained from geometrically similar models.

Values are quoted in Table 4.4-1 for unrecoverable pressure loss across the reactor vessel, including the inlet and outlet nozzles, and across the core. The results of full-scale tests of core components and fuel assemblies are used in developing the core pressure loss characteristic.

Tests of the primary coolant loop flow rates are made prior to initial criticality as described in subsection 4.4.5.1, to verify that the flow rates used in the design, which are determined in part from the pressure losses calculated by the method described here, are conservative. See Section 14.2 for preoperational testing.

4.4.2.7.3 Void Fraction Correlation

VIPRE-01 considers two-phase flow in two steps. First, a quality model is used to compute the flowing vapor mass fraction (true quality) including the effects of subcooled boiling. Then, given the true void quality, a bulk void model is applied to compute the vapor volume fraction (void fraction).

VIPRE-01 uses a profile fit model (Reference 83) for determining subcooled quality. It calculates the local vapor volumetric fraction in forced convection boiling by: 1) predicting the point of bubble departure from the heated surface and 2) postulating a relationship between the true local vapor fraction and the corresponding thermal equilibrium value.

The void fraction in the bulk boiling region is predicted by using homogeneous flow theory and assuming no slip. The void fraction in this region is therefore a function only of the thermodynamic quality.

4.4.2.8 Thermal Effects of Operational Transients

DNB core safety limits are generated as a function of coolant temperature, pressure, core power, and axial power imbalance. Steady-state operation within these safety limits provides that the DNB design basis is met. Subsection 15.0.6 discusses the overtemperature ΔT trip (based on DNBR limit) versus T_{avg}. This system provides protection against anticipated operational transients that are slow with respect to fluid transport delays in the primary system. In addition, for fast transients (such as uncontrolled rod bank withdrawal at power incident as described in subsection 15.4.2, specific protection functions are provided as described in Section 7.2. The use of these protection functions is described in Chapter 15.

4.4.2.9 Uncertainties in Estimates

4.4.2.9.1 Uncertainties in Fuel and Clad Temperatures

As described in subsection 4.4.2.11, the fuel temperature is a function of crud, oxide, clad, pellet-clad gap, and pellet conductances. Uncertainties in the fuel temperature calculation are essentially of two types: fabrication uncertainties, such as variations in the pellet and clad dimensions and the pellet density; and model uncertainties, such as variations in the pellet conductivity and the gap conductance. These uncertainties have been quantified by comparison of the thermal model to the in-pile thermocouple measurements (References 30 through 36), by out-of-pile measurements of the fuel and clad properties (References 37 through 48), and by measurements of the fuel and clad dimensions during fabrication. The resulting uncertainties are then used in the evaluations involving the fuel temperature. The effect of densification on fuel temperature uncertainties is also included in the calculation of the total uncertainty.

In addition to the temperature uncertainty described above, the measurement uncertainty in determining the local power and the effect of density and enrichment variations on the local power are considered in establishing the heat flux hot channel factor. These uncertainties are described in subsection 4.3.2.2.1.

Reactor trip setpoints, as specified in the technical specifications, include allowance for instrument and measurement uncertainties such as calorimetric error, instrument drift and channel reproducibility, temperature measurement uncertainties, noise, and heat capacity variations.

Uncertainty in determining the cladding temperature results from uncertainties in the crud and oxide thicknesses. Because of the excellent heat transfer between the surface of the rod and the coolant, the film temperature drop does not appreciably contribute to the uncertainty.

4.4.2.9.2 Uncertainties in Pressure Drops

Core and vessel pressure drops based on the best-estimate flow, as described in Section 5.1, are quoted in Table 4.4-1. The uncertainties quoted are based on the uncertainties in both the test results and the analytical extension of these values to the reactor application.

A major use of the core and vessel pressure drops is to determine the primary system coolant flow rates, as described in Section 5.1. In addition, as described in subsection 4.4.5.1, tests on primary system prior to initial criticality, are conducted to verify that a conservative primary system coolant flow rate has been used in the design and analysis of the plant.

4.4.2.9.3 Uncertainties Due to Inlet Flow Maldistribution

The effects of uncertainties in the inlet flow maldistribution criteria used in the core thermal analyses are described in subsection 4.4.4.2.2.

4.4.2.9.4 Uncertainty in DNB Correlation

The uncertainty in the DNB correlation described in subsection 4.4.2.2, is written as a statement on the probability of not being in DNB based on the statistics of the DNB data. This is described in subsection 4.4.2.2.2.

4.4.2.9.5 Uncertainties in DNBR Calculations

The uncertainties in the DNBRs calculated by the VIPRE-01 analyses, discussed in subsection 4.4.4.5.1, due to uncertainties in the nuclear peaking factors are accounted for by applying conservatively high values of the nuclear peaking factors. Measurement error allowances are included in the statistical evaluation of the limit DNBR described in subsection 4.4.1.1 using the Revised Thermal Design Procedure. More information is provided in WCAP-11397-P-A (Reference 2). In addition, conservative values for the engineering hot channel factors are used as presented in subsection 4.4.2.2.4. The results of a sensitivity study, WCAP-8054-P-A (Reference 22), with THINC-IV, a VIPRE-01 equivalent code, show that the minimum DNBR in the hot channel is relatively insensitive to variations in the core-wide radial power distribution (for the same value of $F_{\Delta H}^{N}$).

The ability of the VIPRE-01 computer code to accurately predict flow and enthalpy distributions in rod bundles is discussed in subsection 4.4.4.5.1 and in Reference 83. Studies (Reference 84) have been performed to determine the sensitivity of the minimum DNBR to the void fraction correlation (see also subsection 4.4.2.7.3) and the inlet flow distributions. The results of these studies show that the minimum DNBR is relatively insensitive to variation in these parameters. Furthermore, the VIPRE-01 flow field model for predicting conditions in the hot channels is consistent with that used in the derivation of the DNB correlation limits including void/quality modeling, turbulent mixing and crossflow and two phase flow (Reference 83).

4.4.2.9.6 Uncertainties in Flow Rates

The uncertainties associated with reactor coolant loop flow rates are discussed in Section 5.1. A thermal design flow is defined for use in core thermal performance evaluations accounting for both prediction and measurement uncertainties. In addition, another 5.9 percent of the thermal design flow is assumed to be ineffective for core heat removal capability because it bypasses the core through the various available vessel flow paths described in subsection 4.4.4.2.1.

4.4.2.9.7 Uncertainties in Hydraulic Loads

As described in subsection 4.4.2.6.2, hydraulic loads on the fuel assembly are evaluated for a pump overspeed transient which creates flow rates 18 percent greater than the best estimate flow. The best estimate flow is the most likely flow rate value for the actual plant operating condition.

4.4.2.9.8 Uncertainty in Mixing Coefficient

A conservative value of the mixing coefficient, that is, the thermal diffusion coefficient, is used in the VIPRE-01 analyses.

4.4.2.10 Flux Tilt Considerations

Significant quadrant power tilts are not anticipated during normal operation since this phenomenon is caused by some asymmetric perturbation. A dropped or misaligned rod cluster control assembly could cause changes in hot channel factors. These events are analyzed separately in Chapter 15.

Other possible causes for quadrant power tilts include X-Y xenon transients, inlet temperature mismatches, enrichment variations within tolerances, and so forth.

In addition to unanticipated quadrant power tilts as described above, other readily explainable asymmetries may be observed during calibration of the ex-core detector quadrant power tilt alarm. During operation, in-core maps are taken at least one per month and additional maps are obtained periodically for calibration purposes. Each of these maps is reviewed for deviations from the expected power distributions.

Asymmetry in the core, from quadrant to quadrant, is frequently a consequence of the design when assembly and/or component shuffling and rotation requirements do not allow exact symmetry preservation. In each case, the acceptability of an observed asymmetry, planned or otherwise, depends solely on meeting the required accident analyses assumptions. In practice, once acceptability has been established by review of the incore maps, the quadrant power tilt alarms and related instrumentation are adjusted to indicate zero quadrant power tilt ratio as the final step in the calibration process. This action confirms that the instrumentation is correctly calibrated to alarm in the event an unexplained or unanticipated change occurs in the quadrant-to-quadrant relationships between calibration intervals.

Proper functioning of the quadrant power tilt alarm is significant. No allowances are made in the design for increased hot channel factors due to unexpected developing flux tilts, since likely causes are presented by design or procedures or are specifically analyzed.

Finally, in the event that unexplained flux tilts do occur, the Technical Specifications provide appropriate corrective actions to provide continued safe operation of the reactor.

4.4.2.11 Fuel and Cladding Temperatures

Consistent with the thermal-hydraulic design bases described in subsection 4.4.1, the following discussion pertains mainly to fuel pellet temperature evaluation. A description of fuel clad integrity is presented in subsection 4.2.3.1.

The thermal-hydraulic design provides that the maximum fuel temperature is below the melting point of uranium dioxide, subsection 4.4.1.2. To preclude center melting and to serve as a basis for overpower protection system setpoints, a calculated center-line fuel temperature of 4700°F is selected as the overpower limit. This provides sufficient margin for uncertainties in the thermal evaluations, as described in subsection 4.4.2.9.1. The temperature distribution within the fuel pellet is predominantly a function of the local power density and the uranium dioxide thermal conductivity. However, the computation of radial fuel temperature distributions combines crud, oxide, clad gap, and pellet conductances. The factors which influence these conductances, such as gap size (or contact pressure), internal gas pressure, gas composition, pellet density, and radial power distribution within the pellet, have been combined into a semi-empirical thermal model, discussed in subsection 4.2.3.3, that includes a model for time-dependent fuel densification, as given in WCAP-10851-P-A (Reference 49). This thermal model enables the determination of these factors and their net effects on temperature profiles. The temperature predictions have been compared to in-pile fuel temperature measurements (References 30 through 36, 50 and 85) and melt radius data (References 51 and 52) with good results.

Fuel rod thermal evaluations (fuel centerline, average and surface temperatures) are performed at several times in the fuel rod lifetime (with consideration of time-dependent densification) to determine the maximum fuel temperatures.

The principal factors employed in the determination of the fuel temperature follow.

4.4.2.11.1 Uranium Dioxide Thermal Conductivity

The thermal conductivity of uranium dioxide was evaluated from data reported in References 37 through 48 and 53. At the higher temperatures, thermal conductivity is best obtained by using the integral conductivity to melt. From an examination of the data, it has been concluded that the best estimate is:

$$\int_{o}^{2800} Kdt = 93 \text{ W/cm}$$

This conclusion is based on the integral values reported in References 51 and 53 through 57.

The design curve for the thermal conductivity is shown in Figure 4.4-2. The section of the curve at temperatures between 0° and 1300°C is in agreement with the recommendation of the International Atomic Energy Agency (IAEA) panel (Reference 58). The section of the curve above 1300°C is derived for an integral value of 93 W/cm. (References 51, 53, and 57).

Thermal conductivity for uranium dioxide at 95-percent theoretical density can be represented by the following equation:

$$K = \frac{1}{11.8 + 0.0238\,T} + 8.775 \times 10^{-13}\,T^3$$

where:

K = W/cm-°C
T = °C.

4.4.2.11.2 Radial Power Distribution in Uranium Dioxide Fuel Rods

An accurate description of the radial power distribution as a function of burnup is needed for determining the power level for incipient fuel melting and other important performance parameters, such as pellet thermal expansion, fuel swelling, and fission gas release rates. Radial power distribution in uranium dioxide fuel rods is determined with the neutron transport theory code, LASER. The LASER code has been validated by comparing the code predictions on radial burnup and isotopic distributions with measured radial microdrill data, as detailed in WCAP-6069 (Reference 59) and WCAP-3385-56 (Reference 60). A radial power depression factor, f, is determined using radial power distributions predicted by LASER. The factor, f, enters into the determination of the pellet centerline temperature, T_c, relative to the pellet surface temperature, T_g, through the expression:

$$\int_{T_i}^{T_c} K(T)\,dT = \frac{q''f}{4\pi}$$

where:

K(T) = the thermal conductivity for uranium dioxide with a uniform density distribution
q″ = the linear power generation rate

4.4.2.11.3 Gap Conductance

The temperature drop across the pellet-clad gap is a function of the gap size and the thermal conductivity of the gas in the gap. The gap conductance model is selected so that when combined with the uranium dioxide thermal conductivity model, the calculated fuel center-line temperature reflect the in-pile temperature measurements. A more detailed description of the gap conductance model is presented in WCAP-10851-P-A (Reference 49) and WCAP-15063-P-A (Reference 85).

4.4.2.11.4 Surface Heat Transfer Coefficients

The fuel rod surface heat transfer coefficients during subcooled forced convection and nucleate boiling are presented in subsection 4.4.2.7.1.

4.4.2.11.5 Fuel Clad Temperatures

The outer surface of the fuel rod at the hotspot operates at a temperature a few degrees above fluid temperature for steady-state operation at rated power throughout core life due to the onset of nucleate boiling. At beginning of life this temperature is the same as the clad metal outer surface.

During operation over the life of the core, the buildup of oxides and crud on the fuel rod surface causes the clad surface temperature to increase. Allowance is made in the fuel center melt evaluation for this temperature rise. Since the thermal-hydraulic design basis limits DNB, adequate heat transfer is provided between the fuel clad and the reactor coolant so that the core thermal output is not limited by considerations of clad temperature.

4.4.2.11.6 Treatment of Peaking Factors

The total heat flux hot channel factor, F_Q, is defined by the ratio of the maximum-to-core-average heat flux. The design value of F_Q, as presented in Table 4.3-2 and described in subsection 4.3.2.2.6, is 2.6 for normal operation.

As described in subsection 4.3.2.2.6, the peak linear power resulting from overpower transients/operator errors (assuming a maximum overpower of 118 percent) is 22.5 kW/ft. The centerline fuel temperature must be below the uranium dioxide melt temperature over the lifetime of the rod, including allowances for uncertainties. The fuel temperature design basis is described in subsection 4.4.1.2 and results in a maximum allowable calculated center-line temperature of 4700°F. The peak linear power for prevention of center-line melt is greater than 22.5 kW/ft. The center-line temperature at the peak linear power resulting from overpower transients/operator errors (assuming a maximum overpower of 118 percent) is below that required to produce melting.

4.4.3 Description of the Thermal and Hydraulic Design of the Reactor Coolant System

4.4.3.1 Plant Configuration Data

Plant configuration data for the thermal-hydraulic and fluid systems external to the core are provided as appropriate in Chapters 5, 6, and 9. Areas of interest are as follows:

- Total coolant flow rates for the reactor coolant system and each loop are provided in Table 5.1-3. Flow rates employed in the evaluation of the core are presented throughout Section 4.4.

- Total reactor coolant system volume including pressurizer and surge line and reactor coolant system liquid volume, including pressurizer water at steady-state power conditions, are given in Table 5.1-2.

- The flow path length through each volume may be calculated from physical data provided in Table 5.1-2.

- Line lengths and sizes for the passive core cooling system are determined to provide a total system resistance which will provide, as a minimum, the fluid delivery rates assumed in the safety analyses described in Chapter 15.
- The parameters for components of the reactor coolant system are presented in Section 5.4.
- The steady-state pressure drops and temperature distributions through the reactor coolant system are presented in Table 5.1-1.

4.4.3.2 Operating Restrictions on Pumps

The minimum net positive suction head is established before operating the reactor coolant pumps. The operator verifies that the system pressure satisfies net positive suction head requirements prior to operating the pumps.

4.4.3.3 Power-Flow Operating Map (Boiling Water Reactor BWR])

This subsection is not applicable to AP1000.

4.4.3.4 Temperature-Power Operating Map (PWR)

The relationship between reactor coolant system temperature and power is a linear relationship between zero and 100-percent power.

The effects of reduced core flow due to inoperative pumps is described in subsections 5.4.1 and 15.2.6 and Section 15.3. The AP1000 does not include power operation with one pump out of service. Natural circulation capability of the system is described in subsection 5.4.2.3.2.

4.4.3.5 Load Following Characteristics

Load follow using control rod and gray rod motion is described in subsection 4.3.2.4.16. The reactor power is controlled to maintain average coolant temperature at a value which is a linear function of load, as described in Section 7.7.

4.4.3.6 Thermal and Hydraulic Characteristics Summary Table

The thermal and hydraulic characteristics are given in Tables 4.1-1, 4.4-1, and 4.4-2.

4.4.4 Evaluation

4.4.4.1 Critical Heat Flux

The critical heat flux correlations used in the core thermal analysis are explained in subsection 4.4.2.

4.4.4.2 Core Hydraulics

4.4.4.2.1 Flow Paths Considered in Core Pressure Drop and Thermal Design

The following flow paths for core bypass are considered:

A. Flow through the spray nozzles into the upper head for head cooling purposes

B. Flow entering into the rod cluster control and gray rod cluster guide thimbles

C. Leakage flow from the vessel inlet nozzle directly to the vessel outlet nozzle through the gap between the vessel and the barrel

D. Flow introduced through the core shroud for the purpose of cooling and not considered available for core cooling

E. Flow in the gaps between the fuel assemblies on the core periphery and the adjacent core shroud.

The above contributions are evaluated to confirm that the design value of the core bypass flow is met.

Of the total allowance, one part is associated with the core and the remainder is associated with the internals (items A, C, D, and E above). Calculations have been performed using drawing tolerances in the worst direction and accounting for uncertainties in pressure losses. Based on these calculations, the core bypass is no greater than the 5.9 percent design value.

Flow model test results for the flow path through the reactor are described in subsection 4.4.2.7.2.

4.4.4.2.2 Inlet Flow Distributions

A core inlet flow distribution reduction of five percent to the hot assembly inlet is used in the VIPRE-01 analyses of DNBR in the AP1000 core. Studies shown in WCAP-8054-P-A (Reference 22), made with THINC-IV, a VIPRE-01 equivalent code, show that flow distributions significantly more nonuniform than five percent have a very small effect on DNBR, which is accounted for in the DNB analysis.

4.4.4.2.3 Empirical Friction Factor Correlations

The friction factor for VIPRE-01 in the axial direction, parallel to the fuel rod axis, is evaluated using a correlation for a smooth tube (Reference 83). The effect of two-phase flow on the friction loss is expressed in terms of the single-phase friction pressure drop and a two-phase friction multiplier. The multiplier is calculated using the homogenous equilibrium flow model.

The flow in the lateral directions, normal to the fuel rod axis, views the reactor core as a large tube bank. Thus, the lateral friction factor proposed by Idel'chik (Reference 64) is applicable. This correlation is of the form:

$$F_L = A\ Re_L^{-0.2}$$

where:

A = a function of the rod pitch and diameter as given in Idel'chik (Reference 64)
Re_L = the lateral Reynolds number based on the rod diameter

The comparisons of predictions to data given in Reference 83 verify the applicability of the VIPRE-01 correlations in PWR design.

4.4.4.3 Influence of Power Distribution

The core power distribution, which is largely established at beginning of life by fuel enrichment, loading pattern, and core power level, is also a function of variables such as control rod worth and position, and fuel depletion through lifetime. Radial power distributions in various planes of the core are often illustrated for general interest. However, the core radial enthalpy rise distribution, as determined by the integral of power up each channel, is of greater importance for DNBR analyses. These radial power distributions, characterized by $F_N^{\Delta H}$ (defined in subsection 4.3.2.2.1), as well as axial heat flux profiles are discussed in the subsections 4.4.4.3.1 and 4.4.4.3.2.

4.4.4.3.1 Nuclear Enthalpy Rise Hot Channel Factor, $F_{\Delta H}^N$

Given the local power density q′ (kW/ft) at a point x, y, z in a core with N fuel rods and height H, then:

$$F_{\Delta H}^N = \frac{\text{hot rod power}}{\text{average rod power}} = \frac{\text{Max} \int_o^H q'\, x_o\, y_o, z_o)\, dz}{\frac{1}{N} \sum_{\text{all rods}} \int_o^H q'\,(x, y, z)\, dz}$$

The way in which $F_{\Delta H}^N$ is used in the DNBR calculation is important. The location of minimum DNBR depends on the axial profile, and the value of DNBR depends on the enthalpy rise to that point. Basically, the maximum value of the rod integral power is used to identify the most likely rod for minimum DNBR. An axial power profile is obtained that, when normalized to the design value of $F_{\Delta H}^N$, recreates the axial heat flux along the limiting rod. The surrounding rods are assumed to have the same axial profile with rod average powers which are typical distributions found in hot assemblies. In this manner, worst-case axial profiles can be combined with worst-case radial distributions for reference DNBR calculations.

It should be noted again that $F_{\Delta H}^{N}$ is an integral and is used as such in DNBR calculations. Local heat fluxes are obtained by using hot channel and adjacent channel explicit power shapes which take into account variations in horizontal power shapes throughout the core.

For operation at a fraction of full power, the design $F_{\Delta H}^{N}$ used is given by:

$$F_{\Delta H}^{N} = F_{\Delta H}^{RTP}[1 + 0.3(1 - P)]$$

where:

$F_{\Delta H}^{N}$ is the limit at rated thermal power (RTP):

P is the fraction of rated thermal power and $F_{\Delta H}^{RTP}$ = 1.59.

The permitted relaxation of $F_{\Delta H}^{N}$ is included in the DNB protection setpoints and allows radial power shape changes with rod insertion to the insertion limits, as detailed in WCAP-7912-P-A (Reference 65). This allows greater flexibility in the nuclear design.

4.4.4.3.2 Axial Heat Flux Distributions

As described in subsection 4.3.2.2, the axial heat flux distribution can vary as a result of rod motion or power change or as a result of a spatial xenon transient which may occur in the axial direction. The ex-core nuclear detectors, as described in subsection 4.3.2.2.7, are used to measure the axial power imbalance. The information from the ex-core detectors is used to protect the core from excessive axial power imbalance. The reference axial shape used in establishing core DNB limits (that is, overtemperature ΔT protection system setpoints) is a chopped cosine with a peak-to-average value of 1.61. The reactor trip system provides automatic reduction of the trip setpoints on excessive axial power imbalance. To determine the magnitude of the setpoint reduction, the reference shape is supplemented by other axial shapes skewed to the bottom and top of the core.

The course of those accidents in which DNB is a concern is analyzed in Chapter 15 assuming that the protection setpoints have been set on the basis of these shapes. In many cases, the axial power distribution in the hot channel changes throughout the course of the accident due to rod motion, coolant temperature, and power level changes.

The initial conditions for the accidents for which DNB protection is required are assumed to be those permissible within the specified axial offset control limits described in subsection 4.3.2.2. In the case of the loss-of-flow accident, the hot channel heat flux profile is very similar to the power density profile in normal operation preceding the accident. It is therefore possible to illustrate the calculated minimum DNBR for conditions representative of the loss-of-flow accident as a function of the flux difference initially in the core. The power shapes are evaluated with a full-power radial peaking factor ($F_{\Delta H}^{N}$) of 1.59. The radial contribution to the hot rod power shape is conservative both for the initial condition and for the condition at the time of minimum DNBR during the loss-of-flow transient. The minimum DNBR is calculated for the design power shape for non-overpower/overtemperature DNB events. This design shape results in calculated DNBR that bounds the normal operation shapes.

4.4.4.4 Core Thermal Response

A general summary of the steady-state thermal-hydraulic design parameters including thermal output and flow rates is provided in Table 4.4-1.

As stated in subsection 4.4.1, the design bases of the application are to prevent DNB and to prevent fuel melting for Condition I and II events. The protective systems described in Chapter 7 are designed to meet these bases. The response of the core to Condition II transients is given in Chapter 15.

4.4.4.5 Analytical Methods

4.4.4.5.1 Core Analysis

The objective of reactor core thermal design is to determine the maximum heat removal capability in all flow subchannels and to show that the core safety limits, as presented in the technical specifications, are not exceeded while combining engineering and nuclear effects. The thermal design takes into account local variations in dimensions, power generation, flow redistribution, and mixing. The Westinghouse version of VIPRE-01, a three-dimensional subchannel code that has been developed to account for hydraulic and nuclear effects on the enthalpy rise in the core and hot channels, is described in Reference 83, VIPRE-01 modeling of a PWR core is based on a one-pass modeling approach (Reference 83). In the one-pass modeling, hot channels and their adjacent channels are modeled in detail, while the rest of the core is modeled simultaneously on a relatively coarse mesh. The behavior of the hot assembly is determined by superimposing the power distribution upon the inlet flow distribution while allowing for flow mixing and flow distribution between flow channels. Local variations in fuel rod power, fuel rod and pellet fabrication, and turbulent mixing are also considered in determining conditions in the hot channels. Conservation equations of mass, axial and lateral momentum, and energy are solved for the fluid enthalpy, axial flow rate, lateral flow, and pressure drop.

4.4.4.5.2 Steady State Analysis

The VIPRE-01 core model as approved by the NRC (Reference 83) is used with the applicable DNB correlations to determine DNBR distributions along the hot channels of the reactor core under all expected operating conditions. The VIPRE-01 code is described in detail in Reference 84, including discussions on code validation with experimental data. The VIPRE-01 modeling method is described in Reference 83, including empirical models and correlations used. The effect of crud on the flow and enthalpy distribution in the core is not directly accounted for in the VIPRE-01 evaluations. However, conservative treatment by the Westinghouse VIPRE-01 modeling method has been demonstrated to bound this effect in DNBR calculations (Reference 83).

Estimates of uncertainties are discussed in subsection 4.4.2.9.

4.4.4.5.3 Experimental Verification

Extensive additional experimental verification of VIPRE-01 is presented in Reference 84.

The VIPRE-01 analysis is based on a knowledge and understanding of the heat transfer and hydrodynamic behavior of the coolant flow and the mechanical characteristics of the fuel elements. The use of the VIPRE-01 analysis provides a realistic evaluation of the core performance and is used in the thermal hydraulic analyses as described above.

4.4.4.5.4 Transient Analysis

VIPRE-01 is capable of transient DNB analysis. The conservation equations in the VIPRE-01 code contain the necessary accumulation terms for transient calculations. The input description can include one or more of the following time dependent arrays:

1. Inlet flow variation
2. Core heat flux variation
3. Core pressure variation
4. Inlet temperature or enthalpy variation

At the beginning of the transient, the calculation procedure is carried out as in the steady state analysis. The time is incremented by an amount determined either by the user of by the time step control options in the code itself. At each new time step the calculations are carried out with the addition of the accumulation terms which are evaluated using the information from the previous time step. This procedure is continued until a preset maximum time is reached.

At time intervals selected by the user, a complete description of the coolant parameter distributions as well as DNBR is printed out. In this manner the variation of any parameter with time can be readily determined.

4.4.4.6 Hydrodynamic and Flow Power Coupled Instability

Boiling flow may be susceptible to thermohydrodynamic instabilities (Reference 68). These instabilities are undesirable in reactors, since they may cause a change in thermohydraulic conditions that may lead to a reduction in the DNB heat flux relative to that observed during a steady flow condition or to undesired forced vibrations of core components. Therefore, a thermo-hydraulic design criterion was developed which states that modes of operation under Condition I and II events shall not lead to thermohydrodynamic instabilities.

Two specific types of flow instabilities are considered for AP1000 operation. These are the Ledinegg (or flow excursion) type of static instability and the density wave type of dynamic instability.

A Ledinegg instability involves a sudden change in flow rate from one steady state to another. This instability occurs (Reference 68) when the scope of the reactor coolant system pressure drop-flow rate curve:

$$\left(\frac{\partial \Delta P}{\partial G} \mid \text{internal}\right)$$

becomes algebraically smaller than the loop supply (pump head) pressure drop-flow rate curve:

$$\left(\frac{\partial \Delta P}{\partial G} \mid \text{external}\right)$$

The criterion for stability is thus:

$$\left(\frac{\partial \Delta P}{\partial G} \mid \text{ internal} \geq \frac{\partial \Delta P}{\partial G} \mid \text{ external}\right)$$

The canned motor pump head curve has a negative slope ($\partial\Delta P/\partial G$ external less than zero), whereas the reactor coolant system pressure drop-flow curve has a positive slope ($\partial\Delta P/\partial G$ internal greater than zero) over the Condition I and Condition II operational ranges. Thus, the Ledinegg instability does not occur.

The mechanism of density wave oscillations in a heated channel has been described by R. T. Lahey and F. J. Moody (Reference 69). Briefly, an inlet flow fluctuation produces an enthalpy perturbation. This perturbs the length and the pressure drop of the single-phase region and causes quality or void perturbations in the two-phase regions that travel up the channel with the flow. The quality and length perturbations in the two-phase region create two-phase pressure drop perturbations. However, since the total pressure drop across the core is maintained by the characteristics of the fluid system external to the core, then the two-phase pressure drop perturbation feeds back to the single-phase region. These resulting perturbations can be either attenuated or self-sustained.

A simple method has been developed by M. Ishii (Reference 70) for parallel closed-channel systems to evaluate whether a given condition is stable with respect to the density wave type of dynamic instability. This method had been used to assess the stability of typical Westinghouse reactor designs, including the design outlined in References 71, 72, and 73, under Condition I and II operation. The results indicate that a large margin-to-density wave instability exists. Increases on the order of 150 percent of rated reactor power would be required for the predicted inception of this type of instability.

The application of the Ishii method (Reference 70) to Westinghouse reactor designs is conservative due to the parallel open-channel feature of Westinghouse pressurized water reactor cores. For such cores, there is little resistance to lateral flow leaving the flow channels of high-power density. There is also energy transfer from channels of high-power density to lower power density channels. This coupling with cooler channels leads to the conclusion that an open-channel

configuration is more stable than the above closed-channel analysis under the same boundary conditions.

Flow stability tests (Reference 74) have been conducted where the closed channel systems were shown to be less stable than when the same channels were cross-connected at several locations. The cross-connections were such that the resistance to channel cross-flow and enthalpy perturbations would be greater than would exist in a pressurized water reactor core which has a relatively low resistance to cross-flow.

Flow instabilities that have been observed have occurred almost exclusively in closed-channel systems operating at low pressures relative to the Westinghouse pressurized water reactor operating pressures. H. S. Kao, T. D. Morgan, and W. B. Parker (Reference 75) analyzed parallel closed-channel stability experiments simulating a reactor core flow. These experiments were conducted at pressures up to 2200 psia. The results showed that, for flow and power levels typical of power reactor conditions, no flow oscillations could be induced above 1200 psia.

Additional evidence that flow instabilities do not adversely affect thermal margin is provided by the data from the rod bundle DNB tests. Many Westinghouse rod bundles have been tested over wide ranges of operating conditions with no evidence of premature DNB or inconsistent data which might be indicative of flow instabilities in the rod bundle.

In summary, it is concluded that thermohydrodynamic instabilities will not occur under Condition I and II for Westinghouse pressurized water reactor designs. A large power margin, greater than 150 percent of rated power, exists to predicted inception of such instabilities. Analysis has been performed which shows that minor plant-to-plant differences in Westinghouse reactor designs such as fuel assembly arrays, power-to-flow ratios, and fuel assembly length do not result in gross deterioration of the above power margins.

4.4.4.7 Fuel Rod Behavior Effects from Coolant Flow Blockage

Coolant flow blockages can occur within the coolant channels of a fuel assembly or external to the reactor core. The effects of fuel assembly blockage within the assembly on fuel rod behavior are more pronounced than external blockages of the same magnitude. In both cases, the flow blockages cause local reductions in coolant flow. The amount of local flow reduction, where the reduction occurs in the reactor, and how far along the flow stream the reduction persists are considerations which will influence the fuel rod behavior. The effects of coolant flow blockages in terms of maintaining rated core performance are determined both by analytical and experimental methods. The experimental data are usually used to augment analytical tools such as computer programs similar to the VIPRE-01 program. Inspection of the DNB correlation (subsection 4.4.2.2 and References 4, 5, and 6) shows that the predicted DNBR is dependent upon the local values of quality and mass velocity.

The VIPRE-01 code is capable of predicting the effects of local flow blockages on DNBR within the fuel assembly on a subchannel basis, regardless of where the flow blockage occurs. Reference 84 shows that, for a fuel assembly similar to the Westinghouse design, VIPRE-01 accurately predicts the flow distribution within the fuel assembly when the inlet nozzle is completely blocked. Full recovery of the flow was found to occur about 30 inches downstream of

the blockage. With the reactor operating at the nominal full-power conditions specified in Table 4.4-1, the effects of an increase in enthalpy and decrease in mass velocity in the lower portion of the fuel assembly would not result in the fuel rods reaching the DNBR limit.

The open literature supports the conclusion that flow blockage in open-lattice cores, similar to the Westinghouse cores, causes flow perturbations which are local to the blockage. For example, A. Ohstubo and S. Uruwashi (Reference 76) show that the mean bundle velocity is approached asymptomatically about four inches downstream from the flow blockage in a single flow cell. Similar results were also found for two and three cells completely blocked. P. Basmer, et al., (Reference 77) tested an open-lattice fuel assembly in which 41 percent of the subchannels were completely blocked in the center of the test bundle between spacer grids. Their results show that the stagnant zone behind the flow blockage essentially disappears after 1.65 L/De or about five inches for their test bundle. They also found that leakage flow through the blockage tended to shorten the stagnant zone or, in essence, the complete recovery length. Thus, local flow blockages within a fuel assembly have little effect on subchannel enthalpy rise. In reality, a local flow blockage would be expected to promote turbulence and, therefore would not likely affect DNBR at all.

Coolant flow blockages induce local cross-flows as well as promote turbulence. Fuel rod behavior is changed under the influence of a sufficiently high cross-flow component. Fuel rod vibration could occur, caused by this cross-flow component, through vortex shedding or turbulent mechanisms. If the cross-flow velocity exceeds the limit established for fluid elastic stability, large amplitude whirling results. The limits for a controlled vibration mechanism are established from studies of vortex shedding and turbulent pressure fluctuations. The cross-flow velocity required to exceed fluid elastic stability limits is dependent on the axial location of the blockage and the characterization of the cross-flow (jet flow or not). These limits are greater than those for vibratory fuel rod wear. Cross-flow velocity above the established limits can lead to mechanical wear of the fuel rods at the grid support locations. Fuel rod wear due to flow-induced vibration is considered in the fuel rod fretting evaluation as discussed in Section 4.2.

4.4.5 Testing and Verification

4.4.5.1 Tests Prior to Initial Criticality

A reactor coolant flow test is performed, as discussed in Chapter 14, following fuel loading but prior to initial criticality. Coolant loop pressure data is obtained in this test. This data allows determination of the coolant flow rates at reactor operating conditions. This test verifies that proper coolant flow rates have been used in the core thermal and hydraulic analysis.

4.4.5.2 Initial Power and Plant Operation

Core power distribution measurements are made at several core power levels, as discussed in Chapter 14. These tests are used to confirm that conservative peaking factors are used in the core thermal and hydraulic analysis.

Additional demonstration of the overall conservatism of the THINC analysis was obtained by comparing THINC predictions to in-core thermocouple measurements, as detailed WCAP-8453-A

(Reference 78). VIPRE-01 has been confirmed to be as conservative as the THINC code in Reference 83.

4.4.5.3 Component and Fuel Inspections

Inspections performed on the manufactured fuel are described in subsection 4.2.4. Fabrication measurements critical to thermal and hydraulic analysis are obtained to verify that the engineering hot channel factors in the design analyses (subsection 4.4.2.2.4) are met.

4.4.6 Instrumentation Requirements

4.4.6.1 Incore Instrumentation

The primary function of the incore instrumentation system is to provide a three-dimensional flux map of the reactor core. This map is used to calibrate neutron detectors used by the protection and safety monitoring system as well as to optimize core performance. A secondary function of the incore instrumentation system is to provide the protection and safety monitoring system with the signals necessary for monitoring core exit temperatures. This secondary function is the result of the mechanical design that groups the detectors used for generating the flux map in the same thimble as the core exit thermocouples.

The incore instrumentation system consists of incore instrument thimble assemblies, which house fixed incore detectors, core exit thermocouple assemblies contained within an inner and outer sheath assembly, and associated signal processing and data processing equipment. There are 42 incore instrument thimble assemblies: each is composed of multiple fixed incore detectors and one thermocouple.

The thimbles are inserted into the active core through the upper head and internals of the reactor vessel. The signals output from the fixed incore detectors are digitized inside containment and multiplexed out of the containment. The signal processing software integral to the incore instrumentation system allows the fixed incore detector signals to be used to calculate an accurate three-dimensional core power distribution suitable for developing calibration information for the excore nuclear instrumentation input to the overtemperature and overpower ΔT reactor trip setpoints. The system is also capable of accurately determining whether the reactor power distribution is currently within the operating limits defined in the technical specifications while the reactor is operating above approximately 20 percent of rated thermal power.

The incore instrument system data processor receives the transmitted digitized fixed incore detector signals from the signal processor and combines the measured data with analytically-derived constants, and certain other plant instrumentation sensor signals, to generate a full three-dimensional indication of nuclear power distribution in the reactor core. It also edits the three-dimensional indication of power distribution to extract pertinent power distribution parameters outputs for use by the plant operators and engineers. The data processor also generates hardcopy representations of the detailed three-dimensional nuclear power indications.

The hardware and software which performs the three-dimensional power distribution calculation are capable of executing the calculation algorithms and constructing graphical and tabular displays of core conditions at intervals of less than one minute. The software provides information to

enable the reactor operator to ascertain how the measured peaking factor performance agrees with the peaking factor performance predicted by the design model used to determine the acceptability of the fuel loading pattern. The analysis software provides information required to activate a visual alarm display to alert the reactor operator about the current existence of, or the potential for, reactor operating limit violations. The calculation algorithms are capable of determining the core average axial offset using a minimum set of the total 42 incore monitor assemblies. A minimum set of incore monitor assemblies is at least 30 operating assemblies, with at least two operating assemblies in each quadrant, prior to nuclear model calibration; and at least 21 operating assemblies, with at least two operating assemblies in each quadrant, after nuclear model calibration. The nuclear model calibration is performed after each new core load. The hardware which performs the online power distribution monitoring is configured such that a single hardware failure will not necessitate a reactor maximum power reduction or restrict normal reactor operations.

During plant operation, the incore instrument thimble assembly is positioned within the fuel assembly and exits through the top of the reactor vessel to containment. The fixed incore detector and core exit thermocouple cables are then routed to different data conditioning and processing stations. The data is processed and the results are available for display in the main control room.

4.4.6.2 Overtemperature and Overpower ΔT Instrumentation

The overtemperature ΔT trip protects the core against low DNBR. The overpower ΔT trip protects against excessive power (fuel rod rating protection).

As described in subsection 7.2.1.1.3, factors included in establishing the overtemperature ΔT and overpower ΔT trip setpoints include the reactor coolant temperature in each loop and the axial distribution of core power as seen by excore neutron detectors.

4.4.6.3 Instrumentation to Limit Maximum Power Output

The signals from the three ranges (source, intermediate, and power) of neutron flux detectors, are used to limit the maximum power output of the reactor within their respective ranges.

There are eight radial locations containing a total of twelve neutron flux detectors installed around the reactor between the vessel and the primary shield. Four proportional counters for the source range are located at the highest fluence portions of the core containing the primary startup sources at an elevation approximately one-fourth of the core height. Four pulse fission chambers for the intermediate range, located in the same instrument wells as the source range detectors, are positioned at an elevation corresponding to one-half of the core height. Four uncompensated ionization chamber assemblies for the power range are installed vertically at the four corners of the core. These assemblies are located equidistant from the reactor vessel along the length and, to minimize neutron flux pattern distortions, within approximately one foot of the reactor vessel. Each power range detector provides two signals corresponding to the neutron flux in the upper and in the lower sections of a core quadrant. The three ranges of detectors are used as inputs to monitor neutron flux from a completely shutdown condition to 120 percent of full power, with the capability of recording overpower excursions up to 200 percent of full power.

The output of the power range channels is used for:

- Protecting the core against the consequences of rod ejection accidents
- Protecting the core against the consequences of adverse power distributions resulting from dropped rods
- The rod speed control function
- Alerting the operator to an excessive power imbalance between the quadrants

The intermediate range detectors also provide signals for the post-accident monitoring system.

Details of the neutron detectors and nuclear instrumentation design and the control and trip logic are given in Chapter 7. The limits on neutron flux operation and trip setpoints are given in the technical specifications.

4.4.6.4 Digital Metal Impact Monitoring System

The digital metal impact monitoring system is a nonsafety-related system that monitors the reactor coolant system for metallic loose parts. It consists of several active instrumentation channels, each comprising a piezoelectric accelerometer (sensor), signal conditioning, and diagnostic equipment. The digital impact monitoring system conforms with Regulatory Guide 1.133.

The digital metal impact monitoring system is designed to detect a loose parts that weigh from 0.25 to 30 pounds, and can also detect impact with a kinetic energy of 0.5 foot-pounds on the inside surface of the reactor coolant system pressure boundary within three feet of a sensor.

The digital impact monitoring system consists of several redundant instrumentation channels, each comprised of a piezoelectric accelerometer (sensor), preamplifier, and signal conditioning equipment. The output signal from each accelerometer is amplified by the preamplifier and signal conditioning equipment before it is processed by a discriminator to eliminate noise and signals which are not indicative of loose part impacts. The system starts up and operates automatically.

The system facilitates performance tests, hardware integrity tests, and the recognition, location, replacement, repair and adjustment of malfunctioning components. System performance tests are made using a hammer as a tool to simulate an impact. Additional system performance testing is performed using special test modules. These modules simulate impacts and test performance of the signal processing equipment. Hardware integrity tests are also performed to verify equipment operation.

The impact detect algorithm, used by the signal processing equipment, is designed to minimize the number of false alarms. False impact detection, attributable to normal hydraulic, mechanical and electrical noise, is minimized by a number of techniques including:

- Utilizing a floating level within the impact detection algorithm. The floating level is based on signal levels not characteristic of an impact, and is generally a function of the background noise level.

- Comparing the impact event with the times and type of normally occurring plant operation events received from plant control system such as a control rod stepping, valve motion, pump start-ups, and others.

- Comparing the number of events detected within a given time interval. For example, a impact occurring more than two times in one minute may be considered as valid, but random impact occurring at sporadic intervals longer than one minute may not be considered as a valid alarm.

The sensors of the impact monitoring system are fastened mechanically to the reactor coolant system at potential loose part collection regions including the upper and lower head region of the reactor pressure vessel, and the reactor coolant inlet region of each steam generator. Sensors are mounted in a manner which protects the sensors from mechanical damage, compensates for thermal expansion and provides a constant holding force throughout the operating range, maintains the mounting resonance frequency greater than 17 kHz.

The equipment inside the containment is designed to remain functional through an earthquake of a magnitude equal to 50 percent of the calculated safe shutdown earthquake and normal environments (radiation, vibration, temperature, humidity) anticipated during the operating lifetime. The two instrument channels associated with the redundant sensors at each reactor coolant system location are physically separated from each other starting at the sensor locations to a point in the plant that is always accessible for maintenance during full-power operation.

The digital metal impact monitoring system is calibrated prior to plant startup. Capabilities exist for subsequent periodic online channel checks and channel functional tests and for offline channel calibrations at refueling outages.

4.4.7 Combined License Information

Combined License applicants referencing the AP1000 certified design will address changes to the reference design of the fuel, burnable absorber rods, rod cluster control assemblies, or initial core design from that presented in the DCD.

Following selection of the actual plant operating instrumentation and calculation of the instrumentation uncertainties of the operating plant parameters as discussed in subsection 7.1.6, Combined License applicants will calculate the design limit DNBR values using the RTDP with these instrumentation uncertainties and confirm that either the design limit DNBR values as described in Section 4.4, “Thermal and Hydraulic Design,” remain valid, or that the safety analysis minimum DNBR bounds the new design limit DNBR values plus DNBR penalties, such as rod bow penalty.

4.4.8 References

1. ANSI N18.2a-75, “Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants.”

2. Friedland, A. J. and Ray, S., “Revised Thermal Design Procedure,” WCAP-11397-P-A (Proprietary) and WCAP-11397-A (Non-Proprietary), April 1989.

3. Christensen, J. A., Allio, R. J., and Biancheria, A., "Melting Point of Irradiated UO_2," WCAP-6065, February 1965.

4. Davidson, S. L. and Kramer, W. R. (Ed.), "Reference Core Report VANTAGE 5 Fuel Assembly," WCAP-10444-P-A (Proprietary) and WCAP-10445-NP-A (Non-Proprietary), September 1985.

5. Tong, L. S., "Boiling Crisis and Critical Heat Flux," AEC Critical Review Series, TID-25887, 1972.

6. Tong, L. S., "Critical Heat Fluxes in Rod Bundles, Two Phase Flow and Heat Transfer in Rod Bundles," Annual Winter Meeting ASME, November 1968, p. 3146.

7. Letter from A. C. Thadani (NRC) to W. J. Johnson (Westinghouse), January 31, 1989, Subject: Acceptance for Referencing of Licensing Topical Report, WCAP-9226-P/9227-NP, "Reactor Core Response to Excessive Secondary Steam Releases."

8. Motley, F. E., Cadek, F. F., "DNB Test Results for R-Grid Thimble Cold Wall Cells," WCAP-7695-L Addendum 1, October 1972.

[*9. Davidson, S. L. (Ed.), "Westinghouse Fuel Criteria Evaluation Process," WCAP-12488-A, October 1994.*]*

10. Tong, L. S., "Prediction of Departure from Nucleate Boiling for an Axially Nonuniform Heat Flux Distribution," Journal of Nuclear Energy 21, pp 241-248, 1967.

11. Reference deleted

12. Cadek, F. F., Motley, F. E., and Dominicis, D. P., "Effect of Axial Spacing on Interchannel Thermal Mixing with the R Mixing Vane Grid," WCAP-7941-P-A (Proprietary) and WCAP-7959-A (Non-Proprietary), January 1975.

13. Rowe, D. S., and Angle, C. W., "Crossflow Mixing Between Parallel Flow Channels During Boiling, Part II Measurements of Flow and Enthalpy in Two Parallel Channels," BNWL-371, Part 2, December 1967.

14. Rowe, D. S., and Angle, C. W., "Crossflow Mixing Between Parallel Flow Channels During Boiling, Part III Effect of Spacers on Mixing Between Two Channels," BNWL-371, Part 3, January 1969.

15. Gonzalez-Santalo, J. M., and Griffith, P., "Two-Phase Flow Mixing in Rod Bundle Subchannels," ASME Paper 72-WA/NE-19.

16. Motley, F. E., Wenzel, A. H., and Cadek, F. F., "The Effect of 17 x 17 Fuel Assembly Geometry on Interchannel Thermal Mixing," WCAP-8298-P-A (Proprietary) and WCAP-8290A (Non-Proprietary), January 1975.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

17. Hill, K. W., Motley, F. E., and Cadek, F. F., "Effect of Local Heat Flux Spikes on DNB in Non Uniform Heated Rod Bundles," WCAP-8174 (Proprietary), August 1973, and WCAP-8202 (Non-Proprietary), August 1973.

18. Cadek, F. F., "Interchannel Thermal Mixing with Mixing Vane Grids," WCAP-7667-P-A (Proprietary) and WCAP-7755-A (Non-Proprietary), January 1975.

19. Skaritka, J., Ed, "Fuel Rod Bow Evaluation," WCAP-8691, Revision 1 (Proprietary) and WCAP-8692, Revision 1 (Non-Proprietary), July 1979.

20. "Partial Response to Request Number 1 for Additional Information on WCAP-8691, Revision 1," Letter from E. P. Rahe, Jr. (Westinghouse) to J. R. Miller (NRC), NS-EPR-2515, October 9, 1981; "Remaining Response to Request Number 1 for Additional Information on WCAP-8691, Revision 1," Letter from E. P. Rahe, Jr. (Westinghouse) to R. J. Miller (NRC), NS-EPR-2572, March 16, 1982.

21. Letter from C. Berlinger (NRC) to E. P. Rahe, Jr. (Westinghouse), Subject: "Request for Reduction in Fuel Assembly Burnup Limit for Calculations of Maximum Rod Bow Penalty," June 18, 1986.

22. Hochreiter, L. E., "Applications of the THINC-IV Program to PWR Design," WCAP-8054-P-A (Proprietary), February 1989 and WCAP-8195 (Non-Proprietary), October 1973.

23. Hochreiter, L. E., Chelemer, H., and Chu, P. T., "THINC-IV, An Improved Program for Thermal-Hydraulic Analysis of Rod Bundle Cores," WCAP-7956-P-A, February 1989.

24. Dittus, F. W., and Boelter, L. M. K., "Heat Transfer in Automobile Radiators of the Tubular Type," California University Publication in Engineering 2, No. 13, 443461, 1930.

25. Weisman, J., "Heat Transfer to Water Flowing Parallel to Tube Bundles," Nuclear Science Engineering 6, pp 78-79, 1959.

26. Thom, J. R. S., et al., "Boiling in Subcooled Water During Flowup Heated Tubes or Annuli," Proceedings of the Institution of Mechanical Engineers 180, Part C, pp 226-246, 1955-1966.

27. Reference deleted

28. Reference deleted

29. Reference deleted

30. Kjaerheim, G., and Rolstad, E., "In-Pile Determination of UO_2, Thermal Conductivity, Density Effects, and Gap Conductance," HPR-80, December 1967.

31. Kjaerheim, G., In-Pile Measurements of Center Fuel Temperatures and Thermal Conductivity Determination of Oxide Fuels, Paper IFA-175 Presented at the European Atomic Energy

Society Symposium on Performance Experience of Water-Cooled Power Reactor Fuel, Stockholm, Sweden, October 1969.

32. Cohen, I., Lustman, B., and Eichenberg, D., "Measurement of the Thermal Conductivity of Metal-Glad Uranium Oxide Rods During Irradiation," WAPD-228, 1960.

33. Clough, D. J., and Sayers, J. B., "The Measurement of the Thermal Conductivity of UO_2, under Irradiation in the Temperature Range 150 to 1600°C," AERE-4690, UKAEA Research Group, Harwell, December 1964.

34. Stora, J. P., et al., "Thermal Conductivity of Sintered Uranium Oxide under In-Pile Conditions," EURAEC-1095, 1964.

35. Devold, I., "A Study of the Temperature Distribution in UO_2, Reactor Fuel Elements," AE-318, Aktiebolaget Atomenergi, Stockholm, Sweden, 1968.

36. Balfour, M. G., Christensen, J. A., and Ferrari, H. M., "In-Pile Measurement of UO_2 Thermal Conductivity," WCAP-2923, 1966.

37. Howard, V. C., and Gulvin, T. G., "Thermal Conductivity Determinations on Uranium Dioxide by a Radial Flow Method," UKAEA IG-Report 51, November 1960.

38. Lucks, C. F., and Deem, H. W., "Thermal Conductivity and Electrical Conductivity of UO_2," in Progress Reports Relating to Civilian Applications, BMI-1448 (Revised) for June 1960, BMI-1489 (Revised) for December 1960, and BMI-1518 (Revised) for May 1961.

39. Daniel, J. L., Matolich, J. Jr., and Deem, H. W., "Thermal Conductivity of UO_2," HW-69945, September 1962.

40. Feith, A. D., "Thermal Conductivity of UO_2 by a Radial Heat Flow Method," TID-21668, 1962.

41. Vogt, J., Grandel, L., and Runfors, U., "Determination of the Thermal Conductivity of Unirradiated Uranium Dioxide," AB Atomenergi Report RMB-527, 1964, Quoted by IAEA Technical Report Series No. 59, "Thermal Conductivity of Uranium Dioxide."

42. Nishijima, T., Kawada, T., and Ishihata, A., "Thermal Conductivity of Sintered UO_2 and $4Al_2O_3$ at High Temperatures," Journal of the American Ceramic Society 48, pp 31-44, 1965.

43. Ainscough, J. B., and Wheeler, M. J., "Thermal Diffusivity and Thermal Conductivity of Sintered Uranium Dioxide," Proceedings of the Seventh Conference of Thermal Conductivity, National Bureau of Standards, Washington, p 467, 1968.

44. Godfrey, T. G., et al., "Thermal Conductivity of Uranium Dioxide and Armco Iron by an Improved Radial Heat Flow Technique," ORNL-3556, June 1964.

45. Stora, J. P., et al., "Thermal Conductivity of Sintered Uranium Oxide Under In-Pile Conditions," EURAEC-1095, August 1964.

46. Bush, A. J., "Apparatus for Measuring Thermal Conductivity to 2500°C," Reporting 64-1P6-401-43 (Proprietary), Westinghouse Research Laboratories, February 1965.

47. Asamoto, R. R., Anselin, F. L., and Conti, A. E., "The Effect of Density on the Thermal Conductivity of Uranium Dioxide," GEAP-5493, April 1968.

48. Kruger, O. L., Heat Transfer Properties of Uranium and Plutonium Dioxide, Paper 11-N-68F, presented at the Fall Meeting of Nuclear Division of the American Ceramic Society, Pittsburgh, September 1968.

49. Weiner, R. A., et al., "Improved Fuel Performance Models for Westinghouse Fuel Rod Design and Safety Evaluations," WCAP-10851-P-A (Proprietary) and WCAP-11873-A (Non-Proprietary), August 1988.

50. Leech, W. J. et al., "Revised PAD Code Thermal Safety Model," WCAP-8720, Addendum 2, October 1982.

51. Duncan, R. N., "Rabbit Capsule Irradiation of UO_2," CVTR Project, CVNA Project, CVNA-142, June 1962.

52. Nelson, R. G., et al., "Fission Gas Release from UO_2 Fuel Rods with Gross Central Melting," GEAP-4572, July 1964.

53. Gyllander, J. A., "In-Pile Determination of the Thermal Conductivity of UO_2 in the Range 500 to 2500°C," AE-411, January 1971.

54. Lyons, M. F., et al., "UO_2 Powder and Pellet Thermal Conductivity During Irradiation," GEAP-5100-1, March 1966.

55. Coplin, D. H., et al., "The Thermal Conductivity of UO_2 by Direct In-Reactor Measurements," GEAP-5100-6, March 1968.

56. Bain, A. S., "The Heat Rating Required to Produce Center Melting in Various UO_2 Fuels," ASTM Special Technical Publication No. 306, Philadelphia, pp 30-46, 1962.

57. Stora, J. P., "In-Reactor Measurements of the Integrated Thermal Conductivity of UO_2 - Effect of Porosity," Transactions of the American Nuclear Society 13, pp 137-138, 1970.

58. International Atomic Energy Agency, "Thermal Conductivity of Uranium Dioxide," Report of the Panel Held in Vienna, April 1965, IAEA Technical Reports Series, No. 59, Vienna, 1966.

59. Poncelet, C. G., "Burnup Physics of Heterogeneous Reactor Lattices," WCAP-6069, June 1965.

60. Nodvick, R. J., "Saxton Core II Fuel Performance Evaluation," WCAP-3385-56, Part II, "Evaluation of Mass Spectrometric and Radiochemical Analyses of Irradiated Saxton Plutonium Fuel," July 1970.

61. Reference deleted

62. Reference deleted

63. Reference deleted

64. Idel'chik, I. E., "Handbook of Hydraulic Resistance," 2nd Edition, Hemisphere Publishing Corp., 1986.

65. McFarlane, A. F., "Power Peaking Factors," WCAP-7912-P-A (Proprietary) and WCAP-7912-A (Non-Proprietary), January 1975.

66. Reference deleted

67. Reference deleted

68. Boure, J. A., Bergles, A. E., and Tong, L. S., "Review of Two-Phase Flow Instability," Nuclear Engineering Design 25, pp 165-192, 1973.

69. Lahey, R. T., and Moody, F. J., The Thermal Hydraulics of a Boiling Water Reactor, American Nuclear Society, 1977.

70. Saha, P., Ishii, M., and Zuber, N., "An Experimental Investigation of the Thermally Induced Flow Oscillations in Two-Phase Systems," Journal of Heat Transfer, pp 616-622, November 1976.

71. Virgil C. Summer Nuclear Station FSAR, Chapter 4, South Carolina Electric & Gas Company, Docket No. 50-395.

72. Byron/Braidwood Stations FSAR, Chapter 4, Commonwealth Edison Company, Docket No. 50-456.

73. South Texas Project Electric Generating Station FSAR, Chapter 4, Houston Lighting and Power Company, Docket No. 50-498.

74. Kakac, S., et al., "Sustained and Transient Boiling Flow Instabilities in a Cross-Connected Four-Parallel-Channel Upflow System," Proceedings of Fifth International Heat Transfer Conference, Tokyo, September 1974.

75. Kao, H. S., Morgan, T. D., and Parker, W. B., "Prediction of Flow Oscillation in Reactor Core Channel," Transactions of the American Nuclear Society 16, pp 212-213, 1973.

76. Ohtsubo, A., and Uruwashi, S., "Stagnant Fluid Due to Local Flow Blockage," Journal of Nuclear Science Technology, No. 7, pp 433-434, 1972.

77. Basmer, P., Kirsh, D., and Schultheiss, G. F., "Investigation of the Flow Pattern in the Recirculation Zone Downstream of Local Coolant Blockages in Pin Bundles," Atomwirtschaft 17, No. 8, pp 416-417, 1972 (in German).

78. Burke, T. M., Meyer, G. E., and Shefcheck, J., "Analysis of Data from the Zion (Unit 1) THINC Verification Test," WCAP-8453-A, May 1976.

79. Reference deleted

80. Reference deleted

81. Davidson, S. L., and Ryan, T. L., "VANTAGE+ Fuel Assembly Reference Core Report," WCAP-12610-P-A (Proprietary) and WCAP-14342-A (Non-Proprietary), April 1995.

82. Smith, L. D., et al., "Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17x17 Rod Bundles with Modified LPD Mixing Vane Grids," WCAP-15025-P-A (Proprietary) and WCAP-15026-NP (Non-Proprietary), April 1999.

83. Sung, Y. X., et al., "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A and WCAP-15306-NP-A, October 1999.

84. Stewart, C. W., et al., "VIPRE-01: A Thermal-Hydraulic Code for Reactor Core," Volume 1-3 (Revision 3, August 1989), Volume 4 (April 1987), NP-2511-CCM-A, Electric Power Research Institute.

85. Slagle, W. H. (ed.) et al., "Westinghouse Improved Performance Analysis and Design Model (PAD 4.0)," WCAP-15063-P-A, Revision 1 (Proprietary) and WCAP-15064-NP-A, Revision 1 (Non-Proprietary), July 2000.

86. Kitchen, T. J., "Generic Safety Evaluation for 17x17 Standard Robust Fuel Assembly (17x17 STD RFA)," SECL-98-056, Revision 0, September 30, 1998.

Table 4.4-1 (Sheet 1 of 2)

THERMAL AND HYDRAULIC COMPARISON TABLE
(AP1000, AP600 AND A TYPICAL WESTINGHOUSE XL PLANT)

Design Parameters	AP1000[(a)]	AP600	Typical XL Plant
Reactor core heat output (MWt)	3400	1933	3800
Reactor core heat output (10^6 BTU/hr)	11601	6596	12,969
Heat generated in fuel (%)	97.4	97.4	97.4
System pressure, nominal (psia)	2250	2250	2250
System pressure, minimal (psia)	2190	2200	2204
Minimum DNBR at nominal conditions			
Typical flow channel	2.80	3.48	2.20
Thimble (cold wall) flow channel	2.74	3.33	2.12
Minimum DNBR for design transients			
Typical flow channel	>1.25[b] >1.22[b]	>1.23	>1.26
Thimble (cold wall)flow channel	>1.25[b] >1.21[b]	>1.22	>1.24
DNB correlation[(c)]	WRB-2M	WRB-2	WRB-1
Coolant conditions[(d)]			
Vessel minimum measured flow rate (MMF)			
10^6 lbm/hr	115.55	74.4	148.9
gpm	301,670	193,200	403,000
Vessel thermal design flow rate (TDF)			
10^6 lbm/hr	113.5	72.9	145.0
gpm	296,000	189,600	392,000
Effective flow rate for heat transfer[(e)]			
10^6 lbm/hr	106.8	66.3	132.7
gpm	278,500	172,500	358,700
Effective flow area for heat transfer (ft^2)	41.5	38.5	51.1
Average velocity along fuel rods (ft/s)[(e)]	15.9	10.6	16.6
Average mass velocity, 10^6 lbm/hr-ft^2[(e)]	2.41	1.72	2.60
Coolant Temperature[(d)(e)]			
Nominal inlet (°F)	535.0	532.8	561.2
Average rise in vessel (°F)	77.2	69.6	63.6
Average rise in core (°F)	81.4	75.8	68.7
Average in core (°F)	578.1	572.6	597.8
Average in vessel (°F)	573.6	567.6	593.0

Table 4.4-1 (Sheet 2 of 2)

THERMAL AND HYDRAULIC COMPARISON TABLE
(AP1000, AP600 AND A TYPICAL WESTINGHOUSE XL PLANT)

Design Parameters	AP1000[(a)]	AP600	Typical XL Plant
Heat transfer			
Active heat transfer surface area (ft^2)[(f)]	56,700	44,884	69,700
Average heat flux (BTU/hr-ft^2)	199,300	143,000	181,200
Maximum heat flux for normal operation (BTU/hr-ft^2)[(g)]	518,200	372,226	498,200
Average linear power (kW/ft)[(f)]	5.72	4.11	5.20
Peak linear power for normal operation (kW/ft)[(g,h)]	14.9	10.7	14.0
Peak linear power resulting from overpower transients/operator errors, assuming a maximum overpower of 118% (kW/ft)[(h)]	$\leq$22.45	22.5	$\leq$22.45
Peak Linear power for prevention of center-line melt (kW/ft)[(i)]	22.5	22.5	22.45
Power density (kW/l of core)[(j)]	109.7	78.82	98.8
Specific power (kW/kg uranium)[(j)]	40.2	28.89	36.6
Fuel central temperature			
Peak at peak linear power for prevention of centerline melt (°F)	4700	4,700	4700
Pressure drop[(k)]			
Across core (psi)	39.9 ± 4.0[(l)]	17.5 ± 1.7	38.8 ± 3.9
Across vessel, including nozzle (psi)	62.3 ± 6.2[(l)]	45.3 ± 4.5	59.7 ± 6.0

Notes:

(a) Robust Fuel Assembly
(b) 1.25 applies to Core and Axial Offset limits; 1.22 and 1.21 apply to all other RTDP transients
(c) WRB-2M is used for AP1000. WRB-2 or W-3 is used for AP1000 where WRB-2M is not applicable. See subsection 4.4.2.2.1 for use of W-3, WRB-2 and WRB-2M correlations
(d) Based on vessel average temperature equal to 573.6°F. Flow rates and temperatures based on 10 percent steam generator tube plugging
(e) Based on thermal design flow and 5.9 percent bypass flow
(f) Based on 157 fuel assemblies and hot densified fuel length
(g) Based on 2.60 F_Q peaking factor
(h) See subsection 4.3.2.2.6
(i) See subsection 4.4.2.11.6
(j) Based on cold dimensions and 95 percent of theoretical density fuel
(k) These are typical values based on best-estimate reactor flow rate as discussed in Section 5.1
(l) Inlet temperature = 536.8°F

Table 4.4-2

VOID FRACTIONS AT NOMINAL REACTOR CONDITIONS WITH DESIGN HOT CHANNEL FACTORS

(BASED ON VIPRE-01)

	Average	Maximum
Core, %	0.0	-
Hot Subchannel, %	0.1	0.9

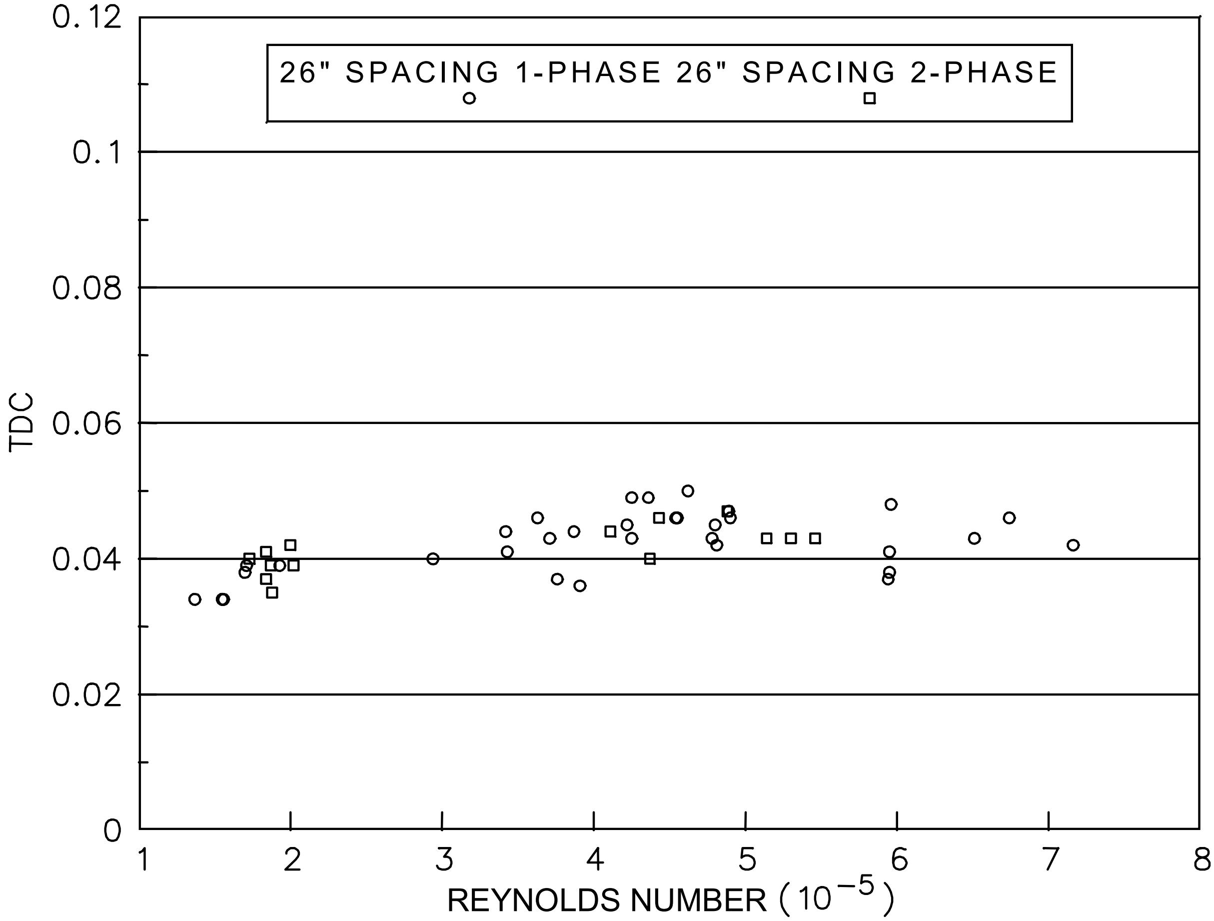


Figure 4.4-1

Thermal Diffusion Coefficient (TDC)
As a Function of Reynolds Number

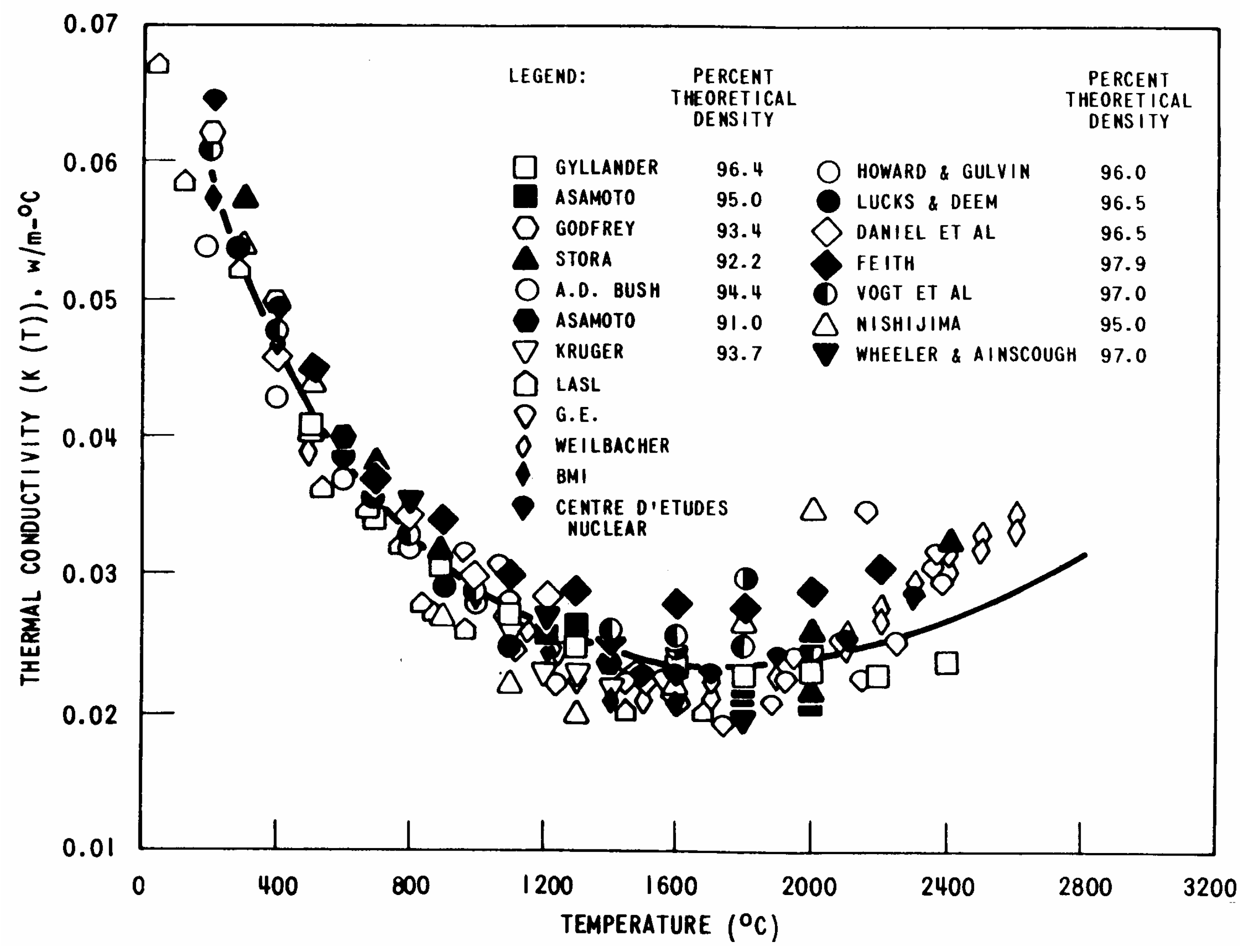


Figure 4.4-2

Thermal Conductivity of Uranium Dioxide (Data Corrected to 95% Theoretical Density)

4.5 Reactor Materials

4.5.1 Control Rod and Drive System Structural Materials

4.5.1.1 Materials Specifications

The parts of the control rod drive mechanisms and control rod drive line exposed to reactor coolant are made of metals that resist the corrosive action of the coolant. Three types of metals are used exclusively: stainless steels, nickel-chromium-iron alloys, and, to a limited extent, cobalt-based alloys. These materials have provided many years of successful operation in similar control rod drive mechanisms. In the case of stainless steels, only austenitic and martensitic stainless steels are used. Where low or zero cobalt alloys are substituted for cobalt-based alloy pins, bars, or hard facing, the substitute material is qualified by evaluation or test.

Pressure-containing materials comply with the ASME Code, Section III. The material specifications for portions of the control rod drive mechanism that are reactor coolant pressure boundary are included in Table 5.2-1. These parts are fabricated from austenitic (Type 316LN and Type 304LN) stainless steel. Nickel-chromium-iron alloy (Alloy 690) is used for the reactor vessel head penetration. For pressure boundary parts, austenitic stainless steels are not used in the heat-treated conditions which can cause susceptibility to stress-corrosion cracking or accelerated corrosion in pressurized water reactor coolant chemistry and temperature environments. Pressure boundary parts and components made of stainless steel do not have specified minimum yield strength greater than 90,000 psi.

The material selection is based in part on the duty cycle specified for the control rod drive mechanisms and control rods. The materials are specified so that the components do not suffer adverse effects, such as excessive wear or galling, as a result of a minimum 300 trips from full power and 60 coupling and decoupling cycles of the drive rod coupling assembly. The material for the control rod drive mechanisms and the control rod assemblies are selected for acceptable performance. That is, the design goal is to achieve a service life of 9 x 10^6 full-step cycles, as a minimum. Inspection or changes in operation indicate the need for replacement or refurbishment. The worst case result of undetected wear of a control rod drive mechanism or drive rod is a rod assembly drop or a failure to drop an assembly during a trip. Both events are accounted for in safety analyses. The pressure boundary components are not subject to significant wear due to stepping cycles.

Internal latch assembly parts are fabricated of heat-treated martensitic and austenitic stainless steel. Heat treatment is such that stress-corrosion cracking is not initiated. Components and parts made of stainless steel do not have specified minimum yield strength greater than 90,000 psi. Magnetic pole pieces are immersed in the reactor coolant and are fabricated from Type 410 stainless steel. Nonmagnetic parts, except pins and springs, are fabricated from Type 304 stainless steel. A cobalt alloy or qualified substitute is used to fabricate link pins. Springs are made from nickel-chromium-iron alloy (Alloy 750). Latch arm tips are clad with a suitable hard facing material to provide improved resistance to wear. Hard chrome plate and hard facing are used selectively for bearing and wear surfaces.

The drive rod assembly is also immersed in the reactor coolant and uses a Type 410 stainless steel drive rod. The drive rod coupling is machined from Type 403 stainless steel. Other parts are Type 304 stainless steel with the exception of the springs, which are nickel-chromium-iron alloy, and the locking button, which is fabricated of cobalt alloy bar stock or a qualified substitute.

The absorber rodlets in the rod control cluster assemblies and the gray rod control assemblies are closed stainless steel tubes (cladding) containing absorber material. The other rodlets in the gray rod control assemblies are constructed of a material similar to the stainless steel cladding of the absorber rods. The stainless steel cladding isolates from the reactor coolant, the absorber material, and other substances inside the tubes. The containment function of the control rod cladding and the effects of neutron flux in the control rod materials is addressed in Section 4.2. The outside surface of the absorber and other rodlets is chromium plated to enhance resistance to wear due to the stepping motion and vibration of the rods. The rods included in one rod control cluster assembly or gray rod control assembly are attached at the top to a common hub which connects with the drive rod of the control rod drive mechanism. The hub is fabricated of type 316 stainless steel.

The coil housing is exposed to containment atmosphere and requires a magnetic material. Low carbon cast steel and ductile iron are qualified by tests or other evaluations for this application. The finished housings are electroless nickel plated to provide resistance against general corrosion.

Coils are wound on composite bobbins, with double glass-insulated copper wire. Coils are vacuum impregnated with silicone varnish. A wrapping of mica sheet is secured to the coil outside diameter. The result is a well-insulated coil capable of sustained operation at 392°F (200°C).

4.5.1.2 Fabrication and Processing of Austenitic Stainless Steel Components

The discussions provided in subsection 5.2.3.4 concerning the processes, inspections, and tests on austenitic stainless steel components to prevent increased susceptibility to intergranular corrosion caused by sensitization are applicable to the austenitic stainless steel pressure-housing components of the control rod drive mechanism. The discussions provided in subsection 5.2.3.4, concerning the control of welding of austenitic stainless steels especially control of delta ferrite are also applicable. Subsection 5.2.3.4 discusses the compliance with the guidelines of Regulatory Guides 1.31, 1.34, and 1.44.

4.5.1.3 Other Materials

When cobalt alloy is used to fabricate link pins in the latch assembly, the material is ordered in the solution-treated, cold-worked condition. Stress-corrosion cracking has not been observed in this application. Where hardfacing material is used in the latch assembly, a cobalt base alloy equivalent to Stellite-6 or qualified low or zero cobalt substitute is used. Low or zero cobalt alloys used for hardfacing or other applications where cobalt alloys have been previously used are qualified using wear and corrosion tests. The corrosion tests qualify the corrosion resistance of the alloy in reactor coolant. Cobalt free wear resistant alloys considered for this application include those developed and qualified in industry programs.

The springs in the control rod drive mechanism are made from nickel-chromium-iron alloy (Alloy 750), ordered to Aerospace Material Specification (AMS) 5698E or AMS 5699E with

additional restrictions on prohibited materials. Operating experience has shown that springs made of this material are not subject to stress-corrosion cracking in pressurized water reactor primary water environments. Alloy 750 is not used for bolting applications in the control rod drive mechanisms.

4.5.1.4 Contamination Protection and Cleaning of Austenitic Stainless Steel

The control rod drive mechanisms are cleaned prior to delivery in accordance with the guidance provided in NQA-1 (see Chapter 17). Process specifications in packaging and shipment are discussed in subsection 5.2.3. Westinghouse personnel conduct surveillance of these operations to verify that manufacturers and installers adhere to appropriate requirements as described in subsection 5.2.3.

Tools used in abrasive work operations on austenitic stainless steel, such as grinding or wire brushing, do not contain and are not contaminated with ferritic carbon steel or other materials that could contribute to intergranular cracking or stress-corrosion cracking.

4.5.2 Reactor Internal and Core Support Materials

4.5.2.1 Materials Specifications

The major core support material for the reactor internals is SA-182, SA-479 or SA-240 Type 304LN stainless steel. For threaded structural fasteners the material used is strain hardened Type 316 stainless steel. Remaining internals parts not fabricated from Type 304LN stainless steel typically include wear surfaces such as hardfacing on the radial keys, clevis inserts, alignment pins (Stellite™ 156 or low cobalt hardfaces); dowel pins (Type 316); hold down spring (Type 403 stainless steel (modified)); and irradiation specimen springs (Type 302 Stainless Steel). Core support structure and threaded structural fastener materials are specified in the ASME Code, Section III, Appendix I as supplemented by Code Cases N-60 and N-4. The qualification of cobalt free wear resistant alloys for use in reactor coolant is addressed in subsection 4.5.1.3.

The use of cast austenitic stainless steel (CASS) is minimized in the AP1000 reactor internals. If used, CASS will be limited in carbon (low carbon grade: L grade) and ferrite contents and will be evaluated in terms of thermal aging effects.

The estimated peak neutron fluence for the AP1000 reactor vessel internals of 9E21 n/cm^2 is acceptable relative to known issues of irradiation-assisted stress corrosion cracking or void swelling in reactor internals. Issues identified in the current pressurized water reactor fleet are being addressed in reactor internals material reliability programs. The Combined License applicant will address findings from these programs that are applicable to the AP1000 reactor internals design (see subsection 3.9.8.2).

4.5.2.2 Controls on Welding

The discussions provided in subsection 5.2.3.4 are applicable to the welding of reactor internals and core support components.

4.5.2.3 Nondestructive Examination of Tubular Products and Fittings

The nondestructive examination of wrought seamless tubular products and fittings is in accordance with ASME Code, Section III, Article NG-2500. The acceptance standards are in accordance with the requirements of ASME Code, Section III, Article NG-5300.

4.5.2.4 Fabrication and Processing of Austenitic Stainless Steel Components

The discussions provided in subsection 5.2.3.4 and Section 1.9 describes the conformance of reactor internals and core support structures with Regulatory Guides 1.31 and 1.44.

The discussion provided in Section 1.9 describes the conformance of reactor internals with Regulatory Guides 1.34 and 1.71.

4.5.2.5 Contamination Protection and Cleaning of Austenitic Stainless Steel

The discussions provided in subsection 5.2.3 and Section 1.9 are applicable to the reactor internals and core support structures describe the conformance of the process specifications with Regulatory Guide 1.37. The process specifications follow the guidance of NQA-1 (Reference 1).

4.5.3 Combined License Information

This section has no requirement for additional information to be provided in support of the Combined License application.

4.6 Functional Design of Reactivity Control Systems

4.6.1 Information for Control Rod Drive System

The control rod drive mechanism (CRDM) and operation of the control rod drive system are described in subsection 3.9.4. Figure 3.9-4 provides the details of the control rod drive mechanisms. Figure 4.2-8 provides the layout of the control rod drive system. No hydraulic system is associated with the functioning of the control rod drive system. The instrumentation and controls for the reactor trip system are described in Section 7.2. The reactor control system is described in Section 7.7.

The control rod drive mechanisms are contained within an integrated head package located on top of the reactor vessel head as described in subsection 3.9.7. This assembly provides the support required for seismic restraint in conjunction with the attachment of the control rod drive mechanisms to the reactor vessel head. An outer shroud, which is an integral portion of the head lifting system and the seismic restraint structure, isolates the control rod drive mechanisms from the effects of ruptures of high-energy lines outside the shroud, and from missiles. The shroud also is used to direct air from the cooling fans past the control rod drive mechanisms. The cooling system maintains the temperatures of the coils in the control rod drive mechanisms below the design operating temperature. The integrated head package provides the proper support and required separation for electrical lines providing power to the control rod drive mechanisms and signals from the rod position sensors.

The lines for the reactor head vent system and the conduits for the in-core instrumentation are located among the control rod drive mechanisms and are supported by the integrated head package. These lines are pressurized to reactor coolant system pressure and considered to be high-energy lines. These lines are constructed to the appropriate requirements of the ASME Code. Figure 3.9-7 shows elements of the integrated head package surrounding the control rod drive mechanisms.

4.6.2 Evaluations of the Control Rod Drive System

Rod control systems of the type used in the AP1000 have been analyzed in detailed reliability studies. These studies include fault tree analysis and failure mode and effects analyses. These studies, and the analyses presented in Chapter 15, demonstrate that the control rod drive system performs its intended safety-related function – a reactor trip. The control rod drive system puts the reactor in a subcritical condition when a safety-related system setting is reached with an assumed credible failure of a single active component.

The essential elements of the control rod drive system (those required to provide reactor trip) are isolated from nonessential portions of the rod control system by the reactor trip switchgear, as described in Section 7.2. The essential portion of the control rod drive system is shielded from the direct effects of postulated moderate- and high-energy line breaks by the integrated head package. The dynamic effects of pipe ruptures do not have to be considered for those pipes that satisfy the requirements for mechanistic pipe break, as outlined in subsection 3.6.3.

The reactor vessel head vent lines and instrumentation conduits are one inch nominal diameter or smaller. Breaks in lines of this size do not have to be postulated for dynamic effects, pressurization, and spray wetting. The pressure boundary housing of the control rod drive mechanisms is constructed to the requirements of the ASME Code and a break in this pressure boundary is not credible.

The only instrumentation required of the control rod drive mechanism and supporting systems to operate safely is the rod position indicator. A break in the cables connected to the rod position indicators would neither preclude a reactor trip, nor would it result in an unplanned withdrawal of a rod assembly. A break in the power cable to the control rod drive mechanism coils results in a drop of the rod assembly. Information on the pressure and temperature of the control rod drive mechanisms and surrounding areas is not required for safe operation. The design pressure and temperature of the control rod drive mechanism housing is the same as the reactor coolant system, which is protected by safety valves. Overheating of the control rod drive mechanism coils due to a failure of the cooling system would in the worst case result in a drop of one or more rod assemblies. The reactor and reactor protection system is designed to accommodate and protect against rod drop events. Additional information is provided in subsection 3.9.1, and Sections 7.2, and 15.4.

4.6.3 Testing and Verification of the Control Rod Drive System

The control rod drive system is extensively tested prior to its operation. These tests may be subdivided into five categories:

- Prototype tests of components
- Prototype control rod drive system tests
- Production tests of components following manufacture and prior to installation
- Onsite pre-operational and initial startup tests
- Periodic in-service tests

These tests, which are described in subsection 3.9.4.4 and Sections 4.2 and 14.2, are conducted to verify the operability of the control rod drive system when called upon to function.

4.6.4 Information for Combined Performance of Reactivity Systems

As indicated in Chapter 15, there are only three postulated events that assume credit for reactivity control systems, other than a reactor trip to render the plant subcritical. These events are the steam-line break, feedwater line break, and small break loss of coolant accident. The reactivity control systems in these accidents are the reactor trip system and the passive core cooling system (PXS). Additional information on the control rod drive system is presented in subsection 3.9.4. The passive core cooling system is discussed further in Section 6.3.

No credit is taken for the boration capabilities of the chemical and volume control system (CVS) as a system in the analysis of transients presented in Chapter 15. Information on the capabilities of the chemical and volume control system is provided in subsection 9.3.6. The adverse boron dilution possibilities due to the operation of the chemical and volume control system are investigated in subsection 15.4.6. Prior proper operation of the chemical and volume control

system has been presumed as an initial condition to evaluate transients. Appropriate technical specifications promote the correct operation or remedial action.

The AP1000 instrumentation and control system includes a diverse actuation system (DAS). This system provides for automatic control rod insertion, turbine trip, passive residual heat removal heat exchanger start, core makeup tank start, isolation of critical containment penetrations, and start of the passive containment cooling system as appropriate upon conditions indicative of an anticipated transient without scram or other failure of the plant control and reactor protection system. This system is diverse and independent from the reactor trip system from the sensor through actuation devices.

In addition to the above, the AP1000 plant systems provide for operator response to an anticipated transient without scram (ATWS) event that includes core reactivity control followed by core decay heat removal. Core reactivity control is provided by a manual trip of the control rods, insertion of the control rods, the chemical and volume control system, or by the core makeup tank injection. The decay heat removal can be performed by the startup feedwater system or the passive residual heat removal system.

4.6.5 Evaluation of Combined Performance

The evaluations of the steam-line break, the feedwater line break, and the small break loss of coolant accident, which presume the combined actuation of the reactor trip system and the control rod drive system and the passive safety injection, are presented in subsections 15.1.5 and 15.2.8 and Section 15.6. Reactor trip signals and signals to actuate passive safety features for these events are generated from functionally diverse sensors. These signals actuate diverse means of reactivity control, that is control rod insertion and injection of soluble neutron absorber.

Non-diverse but redundant types of equipment are used only in the processing of the incoming sensor signals into appropriate logic which initiates the protective action. This equipment is described in Sections 7.2 and 7.3. In particular, protection from equipment failures is provided by redundant equipment and periodic testing. Effects of failures of this equipment have been extensively investigated. Reliability studies, including failure mode and effects analysis for this type of equipment verify that a single failure does not have an adverse effect upon the engineered safety features actuation system. Adequacy of the passive core cooling system performance under faulted conditions is verified in Section 6.3.

In addition to the automatic actuations provided for by the diverse actuation system, that system also provides for manual actuation of the reactor trip.

The probability of a common mode failure impairing the ability of the reactor trip system to perform its safety-related function is extremely low. However, analyses are performed to demonstrate compliance with the requirements of 10 CFR 50.62. These analyses demonstrate that safety criteria would not be exceeded even if the control rod drive system were rendered incapable of functioning during anticipated transients for which its function would normally be expected. The evaluation demonstrates that borated water from the core makeup tank shuts down the reactor with no rods required, and the passive residual heat removal system provides sufficient core heat removal.

4.6.6 Combined License Information

This section has no requirement for additional information to be provided in support of the combined license application.

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

LIST OF TABLES

LIST OF FIGURES

CHAPTER 5

REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 Summary Description

This section describes the reactor coolant system (RCS) and includes a schematic flow diagram of the reactor coolant system (Figure 5.1-1), an isometric view of the reactor coolant loops and major components (Figure 5.1-2), a sketch of the loop layout (Figure 5.1-3), and a sketch of the elevation of the reactor coolant system (Figure 5.1-4, sheets 1 and 2). The piping and instrumentation diagram (Figure 5.1-5, sheets 1, 2, and 3) shows additional details of the design of the reactor coolant system.

5.1.1 Design Bases

The performance and safety design bases of the reactor coolant system and its major components are interrelated. These design bases are listed as follows:

- The reactor coolant system transfers to the steam and power conversion system the heat produced during power operation as well as the heat produced when the reactor is subcritical, including the initial phase of plant cooldown.

- The reactor coolant system transfers to the normal residual heat removal system the heat produced during the subsequent phase of plant cooldown and cold shutdown.

- During power operation and normal operational transients (including the transition from forced to natural circulation), the reactor coolant system heat removal maintain fuel condition within the operating bounds permitted by the reactor control and protection systems.

- The reactor coolant system provides the water used as the core neutron moderator and reflector conserving thermal neutrons and improving neutron economy. The reactor coolant system also provides the water used as a solvent for the neutron absorber used in chemical shim reactivity control.

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

- The reactor coolant system pressure boundary accommodates the temperatures and pressures associated with operational transients.

- The reactor vessel supports the reactor core and control rod drive mechanisms.

- The pressurizer maintains the system pressure during operation and limits pressure transients. During the reduction or increase of plant load, the pressurizer accommodates volume changes in the reactor coolant.

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

- The steam generators provide high-quality steam to the turbine. The tubes and tubesheet boundary prevent the transfer of radioactivity generated within the core to the secondary system.

- The reactor coolant system piping contains the coolant under operating temperature and pressure conditions and limits leakage (and activity release) to the containment atmosphere. The reactor coolant system piping contains demineralized and borated water that is circulated at the flow rate and temperature consistent with achieving the reactor core thermal and hydraulic performance.

- The reactor coolant system is monitored for loose parts, as described in subsection 4.4.6.

- Applicable industry standards and equipment classifications of reactor coolant system components are identified in Tables 3.2-1 and 3.2-3 of subsection 3.2.2.

- The reactor vessel head is equipped with suitable provisions for connecting the head vent system, which meets the requirements of 10 CFR 50.34 (f)(2)(vi) (TMI Action Item II.B.1). (See subsection 5.4.12.)

- The pressurizer surge line and each loop spray line connected with the reactor coolant system are instrumented with resistance temperature detectors (RTDs) attached to the pipe to detect thermal stratification.

5.1.2 Design Description

Figure 5.1-1 shows a schematic of the reactor coolant system. Table 5.1-1 provides the principal pressures, temperatures, and flow rates of the system at the locations noted in Figure 5.1-1 under normal steady-state, full-power operating conditions. These parameters are based on the best-estimate flow at the pump discharge. Table 5.1-2 contains a summary of nominal system design and operating parameters under normal steady-state, full-power operating conditions. These parameters are based on the best-estimate conditions at nominal full power. The reactor coolant system volume under these conditions is also provided.

The reactor coolant system consists of two heat transfer circuits, each with a steam generator, two reactor coolant pumps, and a single hot leg and two cold legs for circulating reactor coolant. In addition, the system includes the pressurizer, interconnecting piping, valves, and instrumentation for operational control and safeguards actuation. All reactor coolant system equipment is located in the reactor containment.

During operation, the reactor coolant pumps circulate pressurized water through the reactor vessel then the steam generators. The water, which serves as coolant, moderator, and solvent for boric acid (chemical shim control), is heated as it passes through the core. It is transported to the steam generators where the heat is transferred to the steam system. Then it is returned to the reactor vessel by the pumps to repeat the process.

The reactor coolant system pressure boundary provides a barrier against the release of radioactivity generated within the reactor and is designed to provide a high degree of integrity throughout operation of the plant.

The reactor coolant system pressure is controlled by operation of the pressurizer, where water and steam are maintained in equilibrium by the activation of electrical heaters or a water spray, or both. Steam is formed by the heaters or condensed by the water spray to control pressure variations due to expansion and contraction of the reactor coolant.

Spring-loaded safety valves are installed above and connected to the pressurizer to provide overpressure protection for the reactor coolant system. These valves discharge into the containment atmosphere. Three stages of reactor coolant system automatic depressurization valves are also connected to the pressurizer. These valves discharge steam and water through spargers to the in-containment refueling water storage tank (IRWST) of the passive core cooling system (PXS). Most (initially all) of the steam and water discharged to the spargers is condensed and cooled by mixing with the water in the tank.

The fourth-stage automatic depressurization valves are connected by two redundant paths to each reactor coolant loop hot leg and discharge directly to the containment atmosphere.

The reactor coolant system is also served by a number of auxiliary systems, including the chemical and volume control system (CVS), the passive core cooling system (PXS), the normal residual heat removal system (RNS), the steam generator system (SGS), the primary sampling system (PSS), the liquid radwaste system (WLS), and the component cooling water system (CCS).

The reactor coolant system includes the following:

- The reactor vessel, including control rod drive mechanism housings.
- The reactor coolant pumps, consisting of four canned motor pumps that pump fluid through the entire reactor coolant and reactor systems and two pumps that are coupled with each steam generator.
- The portion of the steam generators containing reactor coolant, including the channel head, tubesheet, and tubes.
- The pressurizer which is attached by the surge line to one of the reactor coolant hot legs. With a combined steam and water volume, the pressurizer maintains the reactor system within a narrow pressure range.
- The safety and automatic depressurization system valves.
- The reactor vessel head vent isolation valves.
- The interconnecting piping and fittings between the preceding principal components.
- The piping, fittings, and valves leading to connecting auxiliary or support systems.

The piping and instrumentation diagram of the reactor coolant system (Figure 5.1-5) shows the extent of the systems located within the containment and the interface between the reactor coolant system and the secondary (heat utilization) system.

Figures 5.1-3 and 5.1-4 show the plan and section of the reactor coolant loops. These figures show reactor coolant system components in relationship to supporting and surrounding steel and concrete structures. The figures show the protection provided to the reactor coolant system by its physical layout.

5.1.3 System Components

The major components of the reactor coolant system are described in the following subsections. Additional details of the design and requirements of these components are found in other sections of this safety analysis report.

5.1.3.1 Reactor Vessel

The reactor vessel is cylindrical, with a hemispherical bottom head and removable, flanged, hemispherical upper head. The vessel contains the core, core support structures, control rods, and other parts directly associated with the core. The vessel interfaces with the reactor internals, the integrated head package, and reactor coolant loop piping and is supported on the containment building concrete structure.

The design of the AP1000 reactor vessel closely matches the existing vessel designs of Westinghouse three-loop plants. New features for the AP1000 have been incorporated without departing from the proven features of existing vessel designs.

The vessel has inlet and outlet nozzles positioned in two horizontal planes between the upper head flange and the top of the core. The nozzles are located in this configuration to provide an acceptable cross-flow velocity in the vessel outlet region and to facilitate optimum layout of the reactor coolant system equipment. The inlet and outlet nozzles are offset, with the inlet positioned above the outlet, to allow mid-loop operation for removal of a main coolant pump without discharge 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.

5.1.3.2 AP1000 Steam Generator

The AP1000 steam generator (SG) is a vertical shell and U-tube evaporator with integral moisture separating equipment. The basic steam generator design and features have been proven in tests and in previous steam generators including replacement steam generator designs.

Design enhancements include nickel-chromium-iron Alloy 690 thermally treated tubes on a triangular pitch, improved antivibration bars, single-tier separators, enhanced maintenance features, and a primary-side channel head design that allows for easy access and maintenance by robotic tooling. The AP1000 steam generator employs tube supports utilizing a broached hole

support plate design. All tubes in the steam generator are accessible for sleeving, if necessary. The design enhancements are based on proven technology.

The basic function of the AP1000 steam generator is to transfer heat from the single-phase reactor coolant water through the U-shaped heat exchanger tubes to the boiling, two-phase steam mixture in the secondary side of the steam generator. The steam generator separates dry, saturated steam from the boiling mixture, and delivers the steam to a nozzle from which it is delivered to the turbine. Water from the feedwater system replenishes the steam generator water inventory by entering the steam generator through a feedwater inlet nozzle and feedring.

In addition to its steady-state performance function, the steam generator secondary side provides a water inventory which is continuously available as a heat sink to absorb primary side high temperature transients.

5.1.3.3 Reactor Coolant Pumps

The AP1000 reactor coolant pumps are high-inertia, high-reliability, low-maintenance, hermetically sealed canned motor pumps that circulate the reactor coolant through the reactor vessel, loop piping, and steam generators. The pumps are integrated into the steam generator channel head.

The integration of the pump suction into the bottom of the steam generator channel head eliminates the cross-over leg of coolant loop piping; reduces the loop pressure drop; simplifies the foundation and support system for the steam generator, pumps, and piping; and reduces the potential for uncovering of the core by eliminating the need to clear the loop seal during a small loss of coolant accident.

The AP1000 design uses four pumps. Two pumps are coupled with each steam generator.

Each AP1000 reactor coolant pump is a vertical, single-stage centrifugal pump designed to pump large volumes of main coolant at high pressures and temperatures. Because of its canned design, it is more tolerant of off-design conditions that could adversely affect shaft seal designs. The main impeller attaches to the rotor shaft of the driving motor, which is an electric induction motor. The stator and rotor of the motor are both encased in corrosion-resistant cans constructed and supported to withstand full system pressure.

Primary coolant circulates between the stator and rotor which obviates the need for a seal around the motor shaft. Additionally, the motor bearings are lubricated by primary coolant. The motor is thus an integral part of the pump. The basic pump design has been proven by many years of service in other applications.

The pump motor size is minimized through the use of a variable frequency drive to provide speed control in order to reduce motor power requirements during pump startup from cold conditions. The variable frequency drive is used only during heatup and cooldown when the reactor trip breakers are open. During power operations, the drive is isolated and the pump is run at constant speed.

To provide the rotating inertia needed for flow coast-down, a uranium alloy flywheel is attached to the pump shaft.

5.1.3.4 Primary Coolant Piping

Reactor coolant system piping is configured with two identical main coolant loops, each of which employs a single 31-inch inside diameter hot leg pipe to transport reactor coolant to a steam generator. The two reactor coolant pump suction nozzles are welded directly to the outlet nozzles on the bottom of the steam generator channel head. Two 22-inch inside diameter cold leg pipes in each loop (one per pump) transport reactor coolant back to the reactor vessel to complete the circuit.

The loop configuration and material have been selected such that pipe stresses are sufficiently low for the primary loop and large auxiliary lines to meet the requirements to demonstrate "leak-before-break." Thus, pipe rupture restraints are not required, and the loop is analyzed for pipe ruptures only for small auxiliary lines that do not meet the leak-before-break requirements.

5.1.3.5 Pressurizer

The AP1000 pressurizer is a principal component of the reactor coolant system pressure control system. It is a vertical, cylindrical vessel with hemispherical top and bottom heads, where liquid and vapor are maintained in equilibrium saturated conditions.

One spray nozzle and two nozzles for connecting the safety and depressurization valve inlet headers are located in the top head. Electrical heaters are installed through the bottom head. The heaters are removable for replacement. The bottom head contains the nozzle for attaching the surge line. This line connects the pressurizer to a hot leg, and provides for the flow of reactor coolant into and out of the pressurizer during reactor coolant system thermal expansions and contractions.

5.1.3.6 Pressurizer Safety Valves

The pressurizer safety valves are spring loaded, self-actuated with back-pressure compensation. Their set pressure and combined capacity is based on not exceeding the reactor coolant system maximum pressure limit during the Level B service condition loss of load transient.

5.1.3.7 Reactor Coolant System Automatic Depressurization Valves

Some of the functions of the AP1000 passive core cooling system (PXS) are dependent on depressurization of the reactor coolant system. This is accomplished by the automatically actuated depressurization valves. The automatic depressurization valves connected to the pressurizer are arranged in six parallel sets of two valves in series opening in three stages.

A set of fourth-stage automatic depressurization valves is connected to each reactor coolant hot leg. Each set of valves consists of two parallel paths of two valves in series.

To mitigate the consequences of the various accident scenarios, the controls are arranged to open the valves in a prescribed sequence based on core makeup tank level and a timer as described in Section 6.3.

5.1.4 System Performance Characteristics

Table 5.1-3 lists the nominal thermal hydraulic parameters of the reactor coolant system. The system performance parameters are also determined for an assumed 10 percent uniform steam generator tube plugging condition.

Reactor coolant flow is established by a detailed design procedure supported by operating plant performance data and component hydraulics experimental data. The procedure establishes a best-estimate flow and conservatively high and low flows for the applicable mechanical and thermal design considerations. In establishing the range of design flows, the procedure accounts for the uncertainties in the component flow resistances and the pump head-flow capability, established by analysis of the available experimental data. The procedure also accounts for the uncertainties in the technique used to measure flow in the operating plant.

Definitions of the four reactor coolant flows applied in various plant design considerations are presented in the following paragraphs.

5.1.4.1 Best-Estimate Flow

The best-estimate flow is the most likely value for the normal full-power operating condition. This flow is based on the best estimate of the fuel, reactor vessel, steam generator, and piping flow resistances, and on the best estimate of the reactor coolant pump head and flow capability. The best-estimate flow provides the basis for the other design flows required for the system and component design. The best-estimate flow and head also define the performance requirement for the reactor coolant pump. Table 5.1-1 lists system pressure losses based on best-estimate flow.

The best-estimate flow analysis is based on extensive experimental data, including accurate flow and pressure drop data from an operating plant, flow resistance measurements from several fuel assembly hydraulics tests, and hydraulic performance measurements from several pump impeller model tests. Since operating plant flow measurements are in close agreement with the calculated best-estimate flows, the flows established with this design procedure can be applied to the plant design with a high level of confidence.

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.

5.1.4.2 Minimum Measured Flow

The minimum measured flow is specified in the technical specifications as the flow that must be confirmed or exceeded by the flow measurements obtained during plant startup. This is the flow used in reactor core departure from nucleate boiling (DNB) analysis for the thermal design procedure used in the AP1000. In the thermal design procedure methodology for DNB analysis, flow measurement uncertainties are combined statistically with fuel design and manufacturing uncertainties.

The measured reactor coolant flow will most likely differ from the best-estimate flow because of uncertainties in the hydraulics analysis and the inaccuracies in the instrumentation used to measure flow. The measured flow is expected to fall within a range around the best-estimate flow. The magnitude of the expected range is established by statistically combining the system hydraulics uncertainty with the total flow rate within the expected range, less any excess flow margin that may be provided to account for future changes in the hydraulics of the reactor coolant system.

5.1.4.3 Thermal Design Flow

The thermal design flow is the conservatively low value used for thermal-hydraulic analyses where the design and measurement uncertainties are not combined statistically, and additional flow margin must therefore be explicitly included. The thermal design flow is derived by subtracting the plant flow measurement uncertainty from the minimum measured flow. The thermal design flow is approximately 4.5 percent less than the best-estimate flow. The thermal design flow is confirmed when the plant is placed in operation. Table 5.1-3 provides tabulations of important design parameters based on the thermal design flow.

5.1.4.4 Mechanical Design Flow

Mechanical design flow is the conservatively high flow used as the basis for the mechanical design of the reactor vessel internals, fuel assemblies, and other system components. Mechanical design flow is established at 104 percent of best-estimate flow.

5.1.5 Combined License Information

This section has no requirement for additional information to be provided in support of the Combined License application.

Table 5.1-1

PRINCIPAL SYSTEM PRESSURES, TEMPERATURES, AND FLOW RATES

(Nominal Steady-State, Full Power Operating Conditions)

Location (Fig. 5.1-1)	Description	Fluid	Pressure (psig)	Nominal Temp. (°F)	Flow[a] (gpm)
1	Hot Leg 1	Reactor Coolant	2248	610	177,645
2	Hot Leg 2	Reactor Coolant	2248	610	177,645
3	Cold Leg 1A	Reactor Coolant	2310	537.2	78,750
4	Cold Leg 1B	Reactor Coolant	2310	537.2	78,750
5	Cold Leg 2A	Reactor Coolant	2310	537.2	78,750
6	Cold Leg 2B	Reactor Coolant	2310	537.2	78,750
7	Surge Line Inlet	Reactor Coolant	2248	610	-
8	Pressurizer Inlet	Reactor Coolant	2241	653.0	-
9	Pressurizer Liquid	Reactor Coolant	2235	653.0	-
10	Pressurizer Steam	Steam	2235	653.0	-
11	Pressurizer Spray 1A	Reactor Coolant	2310	537.2	1 - 2
12	Pressurizer Spray 1B	Reactor Coolant	2310	537.2	1 - 2
13	Common Spray Line	Reactor Coolant	2310	537.2	2 - 4
14	ADS Valve Inlet	Steam	2235	653.0	-
15	ADS Valve Inlet	Steam	2235	653.0	-

Note:
(a) At the conditions specified.

Table 5.1-2

NOMINAL SYSTEM DESIGN AND OPERATING PARAMETERS

General	
Plant design objective, years	60
NSSS power, MWt	3415
Reactor coolant pressure, psia	2250
Reactor coolant liquid volume at power conditions (including 1000 ft^3 pressurizer liquid), ft^3	9600
Loops	
Number of cold legs	4
Number of hot legs	2
Hot leg ID, in.	31
Cold leg ID, in.	22
Reactor Coolant Pumps	
Type of reactor coolant pumps	Canned-motor
Number of reactor coolant pumps	4
Nameplate motor rating, hp	7000
Effective pump power to coolant, MWt	15
Pressurizer	
Number of units	1
Total volume, ft^3	2100
Water volume, ft^3	1000
Spray capacity, gpm	500
Inside diameter, in.	90
Height, in.	607
Steam Generator	
Steam generator power, MWt/unit	1707.5
Type	Vertical U-tube Feedring-type
Number of units	2
Surface area, ft^2/unit	123,540
Shell design pressure, psia	1200
Zero load temperature, °F	557
Feedwater temperature, °F	440
Exit steam pressure, psia	836
Steam flow, lb/hr per steam generator	$7.49x10^6$
Total steam flow, lb/hr	$14.97x10^6$

Table 5.1-3

THERMAL-HYDRAULIC PARAMETERS

(Nominal)

Detailed Thermal-Hydraulic Parameters		
Best-Estimate Flow (BEF)	**Without Plugging**	**With 10% Tube Plugging**
Flow rate, gpm/loop	157,500	155,500
Reactor vessel outlet temperature, °F	610.0	610.4
Reactor vessel inlet temperature, °F	537.2	536.8
Minimum Measured Flow (MMF)		
Flow rate, gpm/loop	152,775	150,835
Thermal Design Flow (TDF)		
Flow rate, gpm/loop	149,940	148,000
Reactor vessel outlet temperature, °F	611.7	612.2
Reactor vessel inlet temperature, °F	535.5	535.0
Mechanical Design Flow (MDF)		
Flow rate, gpm/flow	163,800	

Best-Estimate Reactor Core and Vessel Thermal-Hydraulic Parameters	**Without Plugging**
NSSS power, MWt	3415
Reactor power, MWt	3400
Best-Estimate loop flow, gpm/loop	157,500
Best-Estimate vessel flow, lb/hr	120.4×10^6
Best-Estimate core flow, lb/hr	113.3×10^6
Reactor coolant pressure, psia	2250
Vessel/core inlet temperature, °F	537.2
Vessel average temperature, °F	573.6
Vessel outlet temperature, °F	610.0
Average core outlet temperature, °F	614.0
Total core bypass flow, (percent of total flow)	5.9
Core barrel nozzle flow	1.0
Head cooling flow	1.5
Thimble flow	1.9
Cavity bypass flow	1.0
Core shroud cooling flow	0.5

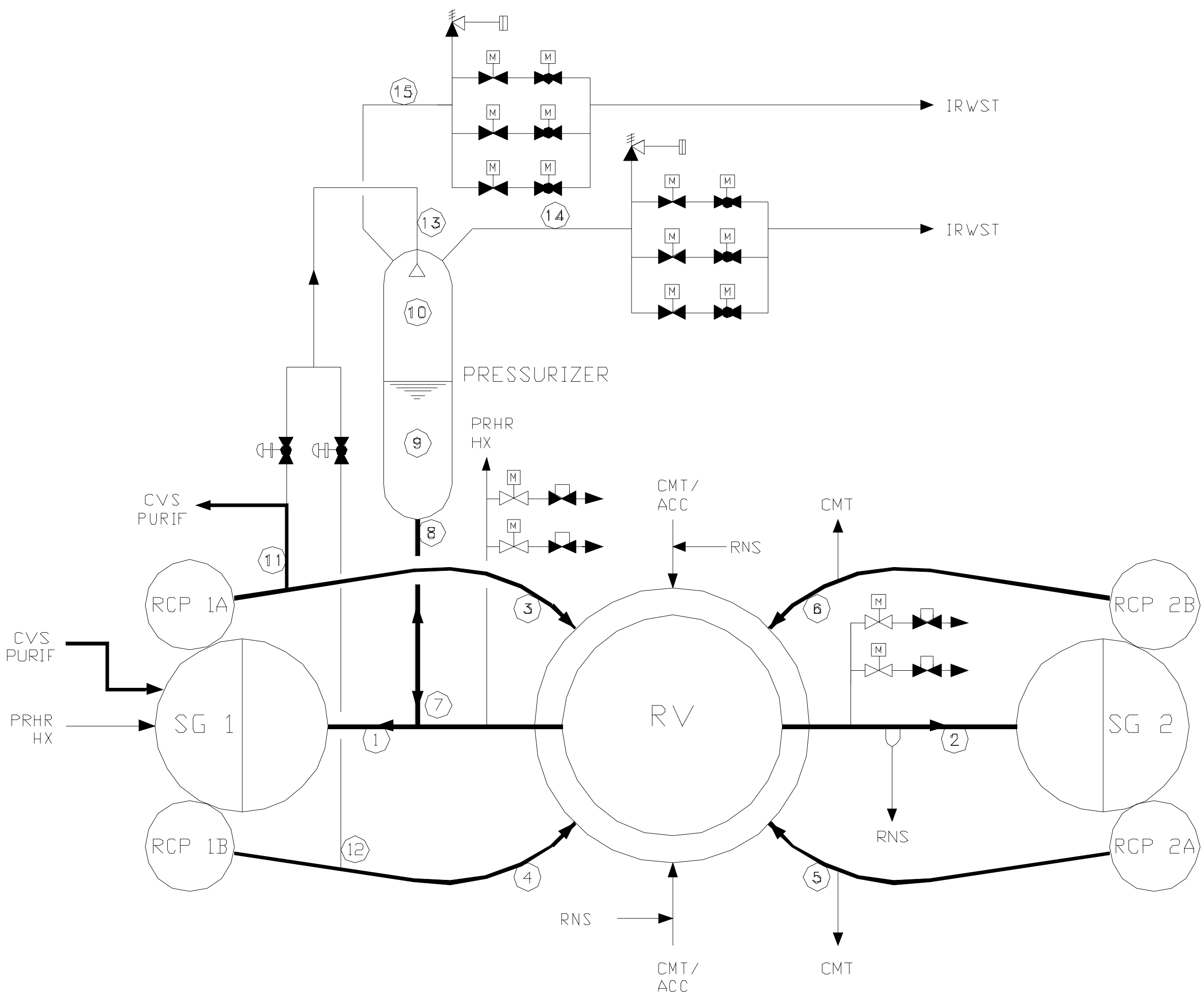


Figure 5.1-1

Reactor Coolant System Schematic Flow Diagram

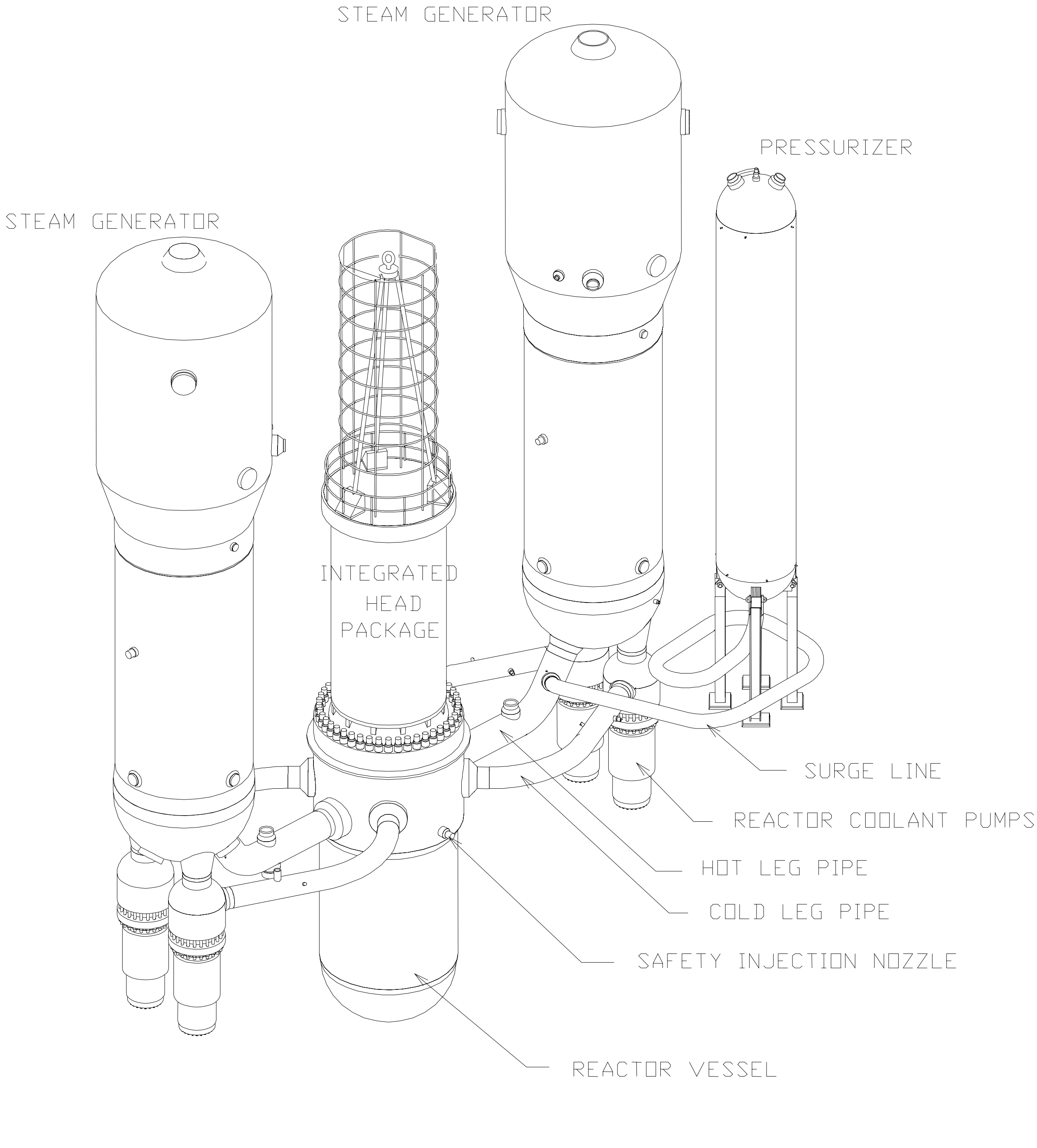


Figure 5.1-2

Reactor Coolant Loops – Isometric View

[This page left intentionally blank]

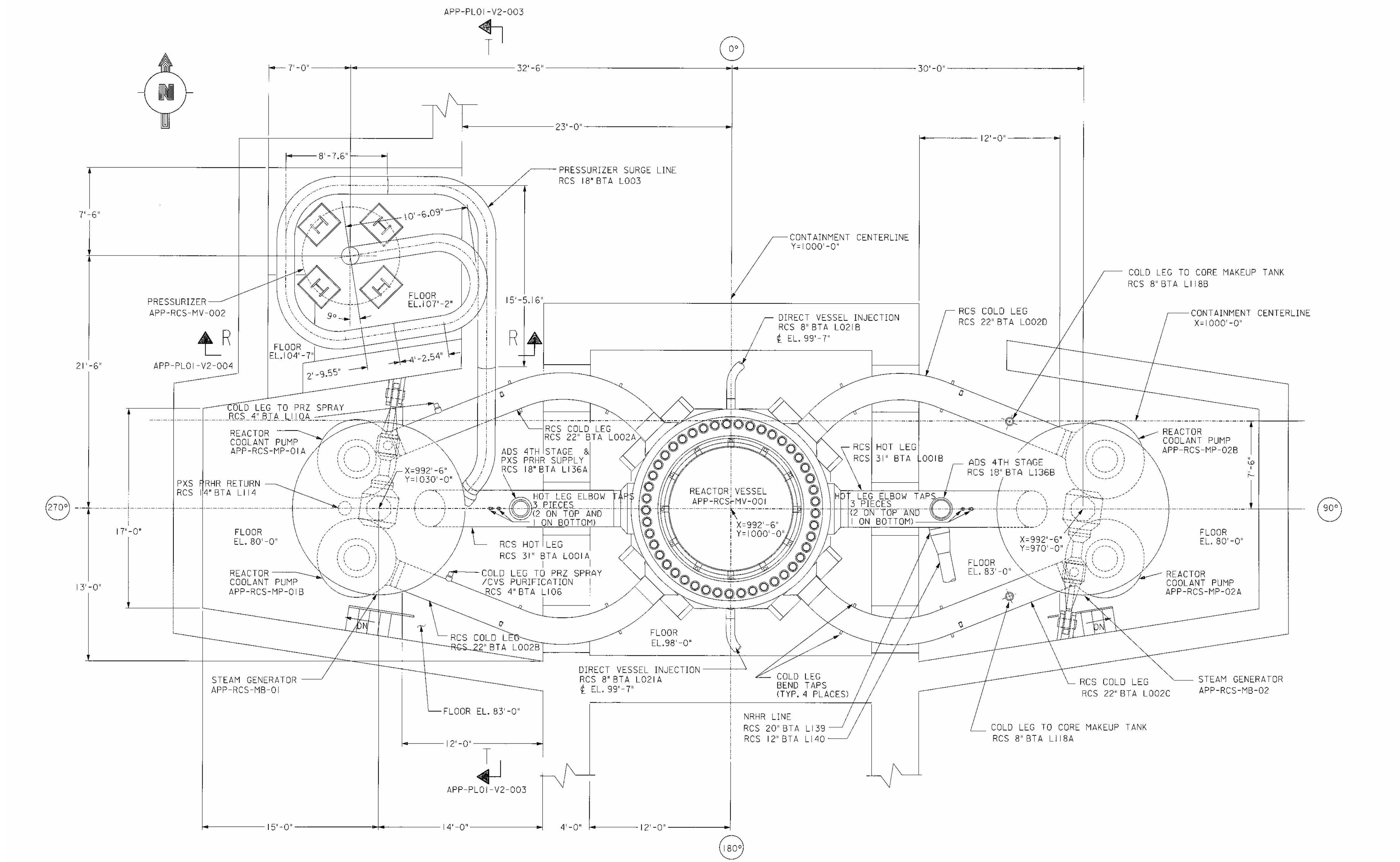


Figure 5.1-3

Reactor Coolant System – Loop Layout

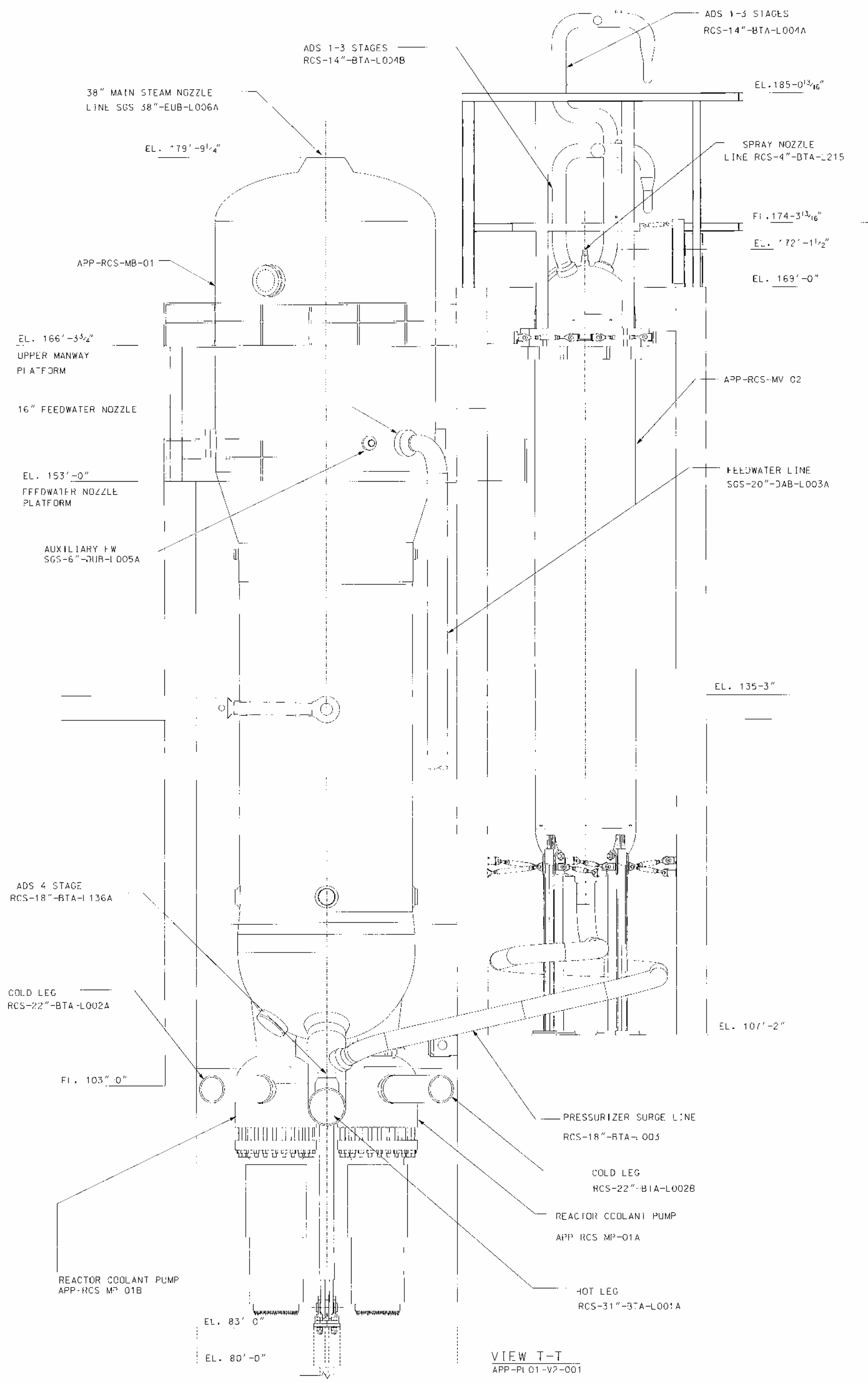
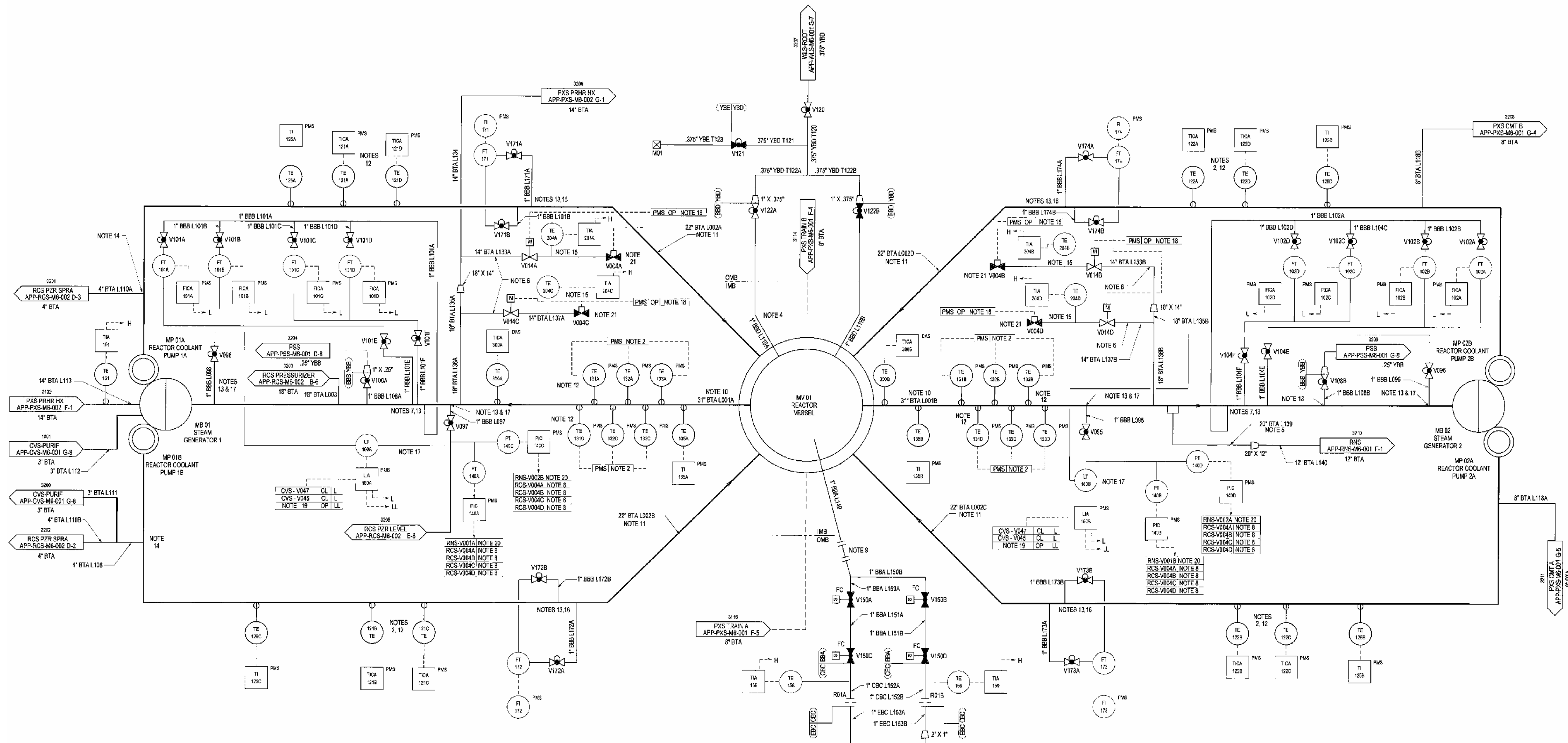


Figure 5.1-4

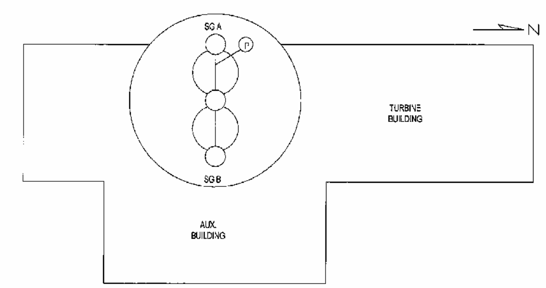
Reactor Coolant System – Elevation

[This page left intentionally blank]



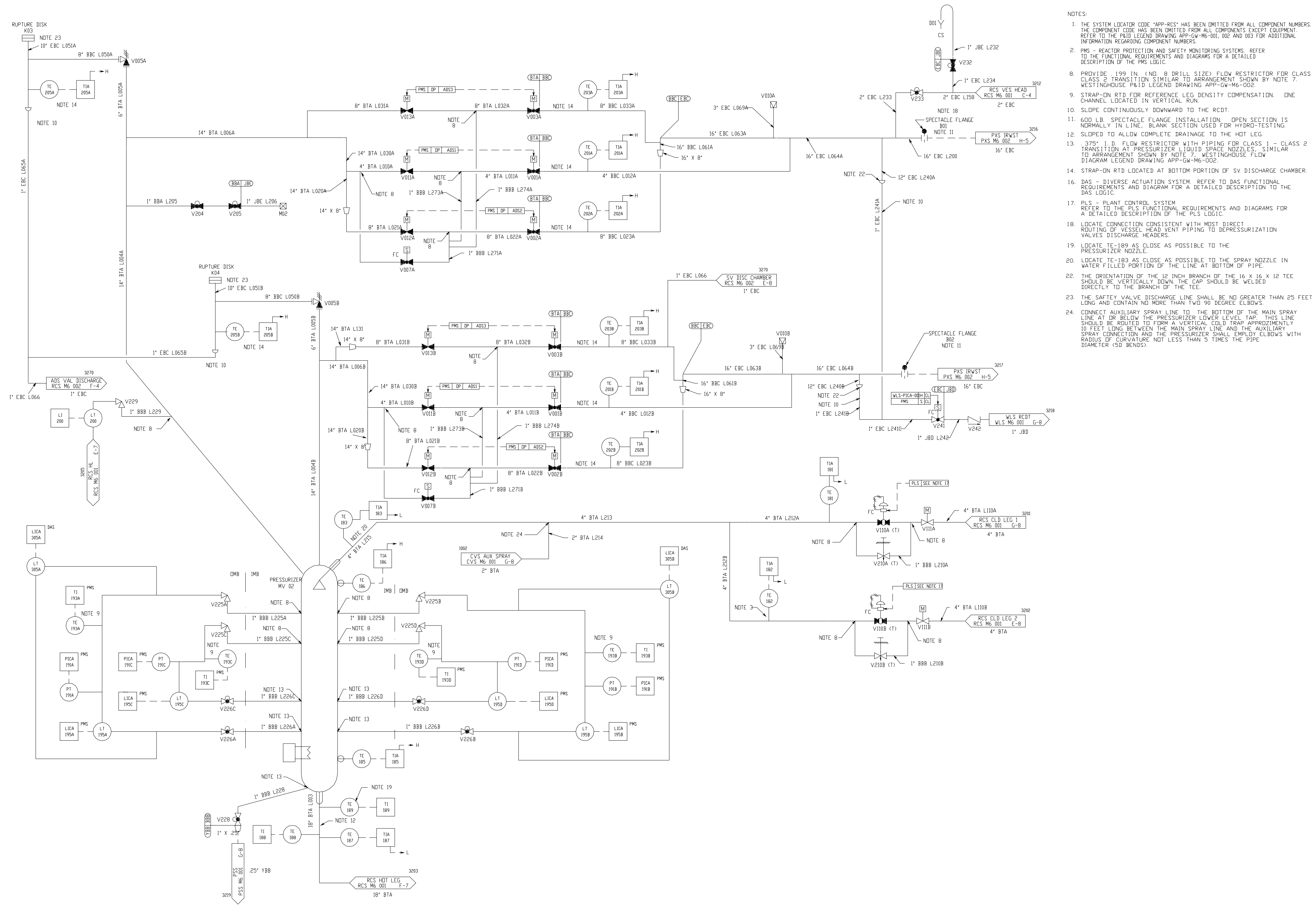
NOTES:

1. THE SYSTEM LOCATOR CODE "APP-RCS" HAS BEEN OMITTED FROM ALL COMPONENT NUMBERS. THE COMPONENT CODE HAS BEEN OMITTED FROM ALL COMPONENTS EXCEPT EQUIPMENT. REFER TO THE P&ID LEGEND DRAWING APP-GW M6 001, 002 AND 003 FOR ADDITIONAL INFORMATION REGARDING COMPONENT NUMBERING.
2. REFER TO RCS SYSTEM SPECIFICATION DOCUMENT (APP-RCS-M3-001) FOR DESCRIPTION OF INSTRUMENTATION, CONTROLS, AND INTERLOCKS.
3. PMS - REACTOR PROTECTION AND SAFETY MONITORING SYSTEM REFER TO THE PMS FUNCTIONAL REQUIREMEMNTS AND DIAGRAVS FOR A DETAILED DESCRIPTION OF THE PMS LOGIC.
4. HEAD GASKET MONITORING CONNECTIONS FURNISHED WITH REACTOR VESSEL.
5. LOCATE CONNECTION IN BOTTOM OF REACTOR COOLANT PIPE, STRAIGHT DOWN. PROVIDE A 2 FOOT SECTION OF 20 IN. PIPE.
5. SLOPE PIPING TO PROVIDE WATER SEAL AT INLET OF VALVES.
7. ELBOW FLOW METER IN HL BEND. INSTALLATION PER REFERENCE (LATER)
8. WIDE RANGE PRESSURE CHANNELS INTERLOCKED TO PERMIT OPENING OF 4TH STAGE ADS SQUIB VALVES.
9. HEAD VENT CONNECTION FURNISHED WITH VESSEL HEAD. SPOOL PIECE PROVIDED TO PERMIT REMOVAL OF RV HEAD FOR REFUELING OPERATIONS.
10. 31' INSIDE DIAMETER.
11. 22" INSIDE DIAMETER.
12. THERMOWELL MOUNTED FAST RESPONSE TEMPERATURE DETECTORS LOCATED IN SAME VERTICAL PLANE.
13. .375" ID FLOW RESTRICTOE FOR CLASS 1TO CLASS 2 TRANSITION SIMILAR TO ARRANGEMENT SHOWN BY NOTE 7, WESTINGHOUSE P&ID LEGEND DRAWINGAPP-GW-M6-002.
14. PRESSURIZER SPRAY SCOOP.
15. LOCATE STRAP-ON RTD ON TOP OF HORIZONTAL RUN OF PIPE.
15. ELBOW FLOW METER IN CL BEND. INSTALLATION PER REFERENCE (LATER)
17. LEVEL INSTRUMENTATION PROVIDED TO MONITOR RCS WATER LEVEL DURING MID-LOOP OPERATION FOLLOWING SHUTDOWN. LOCATE ONE TAP AT BOTTOM OF HOT LEG. FOR CHANNEL LT 160B, THIS SHOULD BE UPSTREAM OF RNS CONNECTION. LOCATE OTHER TAP ON THE TOP OF THE HOT LEG AS CLOSE TO THE SG AS POSSIBLE. TAP AT SG TO BE HIGH-POINT OF TUBING RUN.
18. 4TH STAGE AUTOMATIC DEPRESSURIZATION SIGNAL FROM THE PMS. REFER TO THE PMS FUNCTIONAL REQUIREMENTS AND DIAGRAM FOR A DETAILED DESCRIPTION OF THE PMS LOGIC.
19. PMS - OPENS IRWST INJECTION VALVES ON LOW-LOW (EMPTY) HOT LEG LEVEL PLUS 30 MINUTE TIME DELAY.
20. WIDE RANGE PRESSURE CHANNEL INTERLOCKED TO PERMIT OPENING OF RNS HOT LEG SUCTION LINE ISOLATION VALVES RNS-V001A & B RNS V002A & B.
21. THE 4TH STAGE ADS VALVES DISCHARGE TO THE STEAM GENERATOR COMPARTMENTS AT AN ELEVATION GREATER THAN 110'.
22. DAS - DIVERSE ACTUATION SYSTEM. REFER TO DAS DAS FUNCTIONAL REQUIREMENTS AND DIAGRAMS FOR A DETAILED DESCRIPTION OF THE DAS LOGIC.



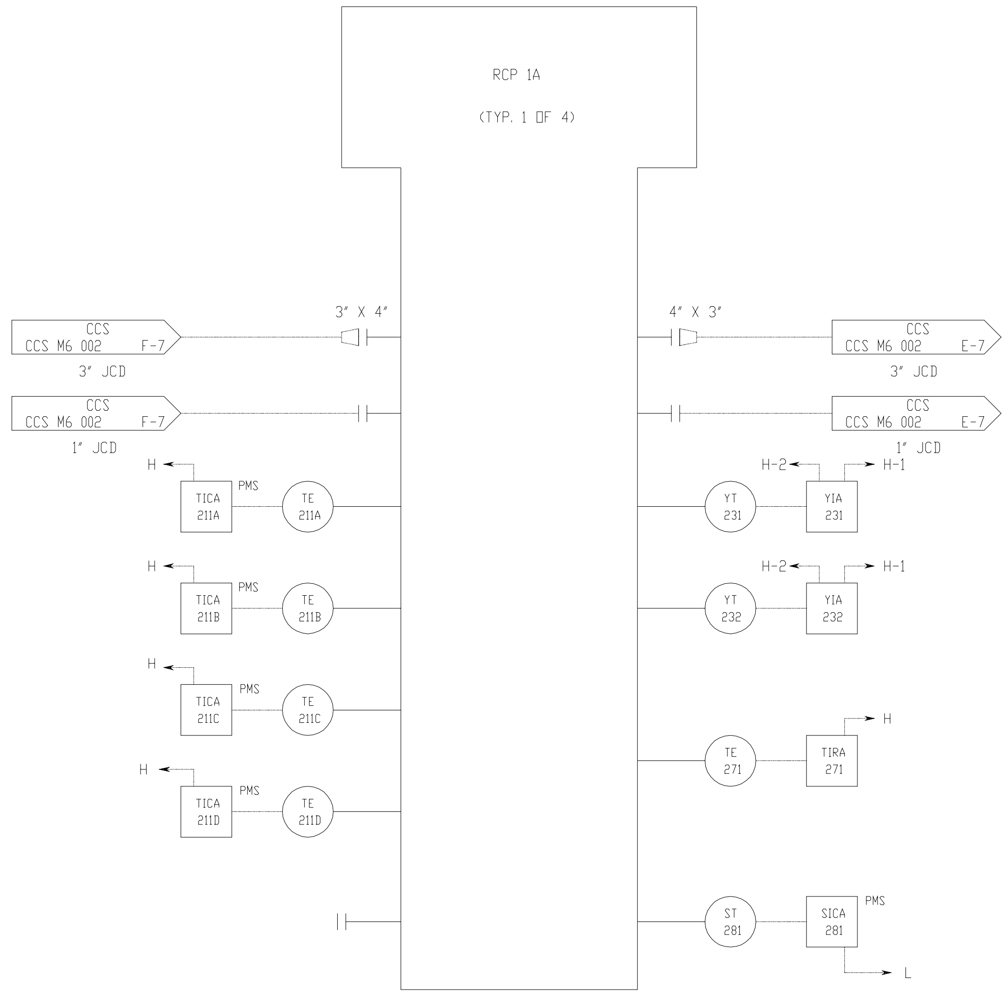
Inside Reactor Containment
Figure 5.1-5 (Sheet 1 of 3)

Reactor Coolant System
Piping and Instrumentation Diagram



Inside Reactor Containment
Figure 5.1-5 (Sheet 2 of 3)

Reactor Coolant System
Piping and Instrumentation Diagram



REACTOR COOLANT PUMP INSTRUMENTATION					
	RCP 1A	RCS 1B	RCP 2A	RCP 2B	SENSOR SUPPLIED WITH PUMP
BEARING WATER TEMPERATURE (TE -)	211A 211B 211C 211D	212A 212B 212C 212D	213A 213B 213C 213D	214A 214B 214C 214D	YES YES YES YES
VIBRATION (YT -)	231 232	233 234	241 242	243 244	YES YES
STATOR TEMPERATURE (TE -)	271	272	273	274	YES
PUMP SPEED (ST -)	281	282	283	284	YES

Inside Reactor Containment
Figure 5.1-5 (Sheet 3 of 3)

Reactor Coolant System
Piping and Instrumentation Diagram

5.2 Integrity of Reactor Coolant Pressure Boundary

This section discusses the measures to provide and maintain the integrity of the reactor coolant pressure boundary (RCPB) during plant operation. Section 50.2 of 10 CFR 50 defines the reactor coolant pressure boundary as vessels, piping, pumps, and valves that are part of the reactor coolant system (RCS), or that are connected to the reactor coolant system up to and including the following:

- The outermost containment isolation valve in system piping that penetrates the containment
- The second of two valves closed during normal operation in system piping that does not penetrate containment
- The reactor coolant system overpressure protection valves

The design transients used in the design and fatigue analysis of ASME Code Class 1 and Class CS components, supports, and reactor internals are provided in subsection 3.9.1. The loading conditions, loading combinations, evaluation methods, and stress limits for design and service conditions for components, core support structures, and component supports are discussed in subsection 3.9.3.

The term reactor coolant system, as used in this section, is defined in Section 5.1. The AP1000 reactor coolant pressure boundary is consistent with that of 10 CFR 50.2.

5.2.1 Compliance with Codes and Code Cases

5.2.1.1 Compliance with 10 CFR 50.55a

Reactor coolant pressure boundary components are designed and fabricated in accordance with the ASME Boiler and Pressure Vessel Code, Section III. A portion of the chemical and volume control system inside containment that is defined as reactor coolant pressure boundary uses an alternate classification in conformance with the requirements of 10 CFR 50.55a(a)(3). Systems other than the reactor coolant system connecting to the chemical and volume control system have required isolation and are not classified as reactor coolant pressure boundary. The alternate classification is discussed in Section 5.2.1.3. The quality group classification for the reactor coolant pressure boundary components is identified in subsection 3.2.2. The quality group classification is used to determine the appropriate sections of the ASME Code or other standards to be applied to the components.

The edition and addenda of the ASME Code applied in the design and manufacture of each component are the edition and addenda established by the requirements of the Design Certification. The use of editions and addenda issued subsequent to the Design Certification is permitted or required based on the provisions in the Design Certification. [*The baseline used for the evaluations done to support this safety analysis report and the Design Certification is the 1998 Edition, 2000 Addenda, except as follows:*

The 1989 Edition, 1989 Addenda is used for Articles NB-3200, NB-3600, NC-3600, and ND-3600 in lieu of later editions and addenda.

The criteria below are used in place of those in paragraph NB-3683.4(c)(1) and Footnote 11 to Figures NC/ND-3673.2(b)-1 of the 1989 Addenda to the 1989 Edition of ASME Code, Section III. This criteria is based on the criteria included in the 1989 Edition of the ASME Code, Section III.

For girth fillet welds between the piping and socket welded fittings, valves and flanges, and slip on flanges in ASME III Class 1, 2, and 3 piping, the primary stress indices and stress intensification factors are as follows:

Primary Stress Indices

$B_1 = 0.75$

$B_2 = 1.5$

Stress Intensification Factor

$i = 2.1*(t_n/C_x)$, *but not less than 1.3*

C_x = *fillet weld leg length based on ASME III 1989 Edition, Figures NC/ND-4427-1, sketches (c-1), (c-2), and (c-3). For unequal leg length, use smaller leg length for* C_x.]*

Seismic Integrity of the CVS System Inside Containment

To provide for the seismic integrity and pressure boundary [*integrity of the nonsafety-related (B31.1, Piping Class D) CVS piping located inside containment, a seismic analysis will be performed and a CVS Seismic Analysis Report prepared with a faulted stress limit equal to the smaller of 4.5* S_h *and 3.0* S_y *and based on the following additional criteria:*

Additional loading combinations and stress limits for nonsafety-related chemical and volume control system piping systems and components inside containment]*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Condition	*Loading Combination*$^{(3)}$	[*Equations (ND3650)*	*Stress Limit*
Level D	*PMAX*$^{(1)}$ *+ DW + SSE + SSES*	*9*	*Smaller of* $4.5\ S_h$ *or* $3.0\ S_y$
	SSES	$F_{AM}/A_M^{(4)}$	$1.0\ S_h$
	TNU + SSES	$i\ (M1 + M2)/Z^{(2)}$	$3.0\ S_h$

Notes:

1. *For earthquake loading, PMAX is equal to normal operating pressure at 100% power.*

2. *Where: M1 is range of moments for TNU, M2 is one half the range of SSES moments, M1 + M2 is larger of M1 plus one half the range of SSES, or full range of SSES.*

3. *See Table 3.9-3 for description of loads.*

4. F_{AM} *is amplitude of axial force for SSES;* A_M *is nominal pipe metal area.*]*

Component supports, equipment, and structural steel frame are evaluated to demonstrate that they do not fail under seismic loads. Design methods and stress criteria are the same as for corresponding Seismic Category I components. The functionality of the chemical and volume control system does not have to be maintained to insure structural integrity of the components.

[*Fabrication, examination, inspection, and testing requirements as defined in Chapters IV, V, VI, and VII of the ASME B31.1 Code are applicable and used for the B31.1 (Piping Class D) CVS piping systems, valves, and equipment inside containment.*]*

5.2.1.2 Applicable Code Cases

[*ASME Code Cases used in the AP1000 are listed in Table 5.2-3.*]* In addition, other ASME Code Cases found in Regulatory Guides 1.84 and 1.85, as discussed in Section 1.9, in effect at the time of the Design Certification may be used for pressure boundary components. Use of Code Cases approved in revisions of the Regulatory Guides issued subsequent to the Design Certification may be used by the Combined License applicant using the process outlined above for updating the ASME Code edition and addenda. Use of any Code Case not approved in Regulatory Guides 1.84 and 1.85 on Class 1 components is authorized as provided in 50.55a(a)(3) and the requirements of the Design Certification.

The use of any Code Case conditionally approved in Regulatory Guides 1.84 and 1.85 used on Class 1 components meets the conditions established in the Regulatory Guide.

5.2.1.3 Alternate Classification

The Code of Federal Regulations, Section 10 CFR 50.55a requires the reactor coolant pressure boundary be class A (ASME Boiler and Pressure Vessel Code Section III, Class 1). Components which are connected to the reactor coolant pressure boundary that can be isolated from the reactor

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

coolant system by two valves in series (both closed, both open, or one closed and the other open) with automatic actuation to close can be classified as class C (ASME Section III, class 3) according to 50.55a.

A portion of the chemical and volume control system inside containment is not classified as safety-related. The classification of the AP1000 reactor coolant pressure boundary deviates from the requirement that the reactor coolant pressure boundary be classified as safety related and be constructed using the ASME Code, Section III as provided in 10 CFR 50.55a. The safety-related classification of the AP1000 reactor coolant pressure boundary ends at the third isolation valve between the reactor coolant system and the chemical and volume control system. The nonsafety-related portion of the chemical and volume control system inside containment provides purification of the reactor coolant and includes heat exchangers, demineralizers, filters and connecting piping. For a description of the chemical and volume control system, refer to subsection 9.3.6. The portion of the chemical and volume control system between the inside and outside containment isolation valves is classified as Class B and is constructed using the ASME Code, Section III.

The nonsafety-related portion of the chemical and volume control system is designed using ANSI B31.1 and ASME Code, Section VIII for the construction of the piping, valves, and components. The nonsafety-related portion of the CVS inside containment is analyzed seismically. The methods and criteria used for the seismic analysis are similar to those used of seismic Category II pipe and are defined in the subsection 5.2.1.1. The chemical and volume control system components are located inside the containment which is a seismic Category I structure.

The alternate classification of the nonsafety-related purification subsystems satisfies the purpose of 10 CFR 50.55a that structures, systems, and components of nuclear power plants which are important to safety be designed, fabricated, erected, and tested to quality standards that reflect the importance of the safety functions to be performed.

The AP1000 chemical and volume control system is not required to perform safety-related functions such as emergency boration or reactor coolant makeup. Safety-related core makeup tanks are capable of providing sufficient reactor coolant makeup for shutdown and cooldown without makeup supplied by the chemical and volume control system. Safe shutdown of the reactor does not require use of the chemical and volume control system makeup. AP1000 safe shutdown is discussed in Section 7.4.

The isolation valves between the reactor coolant system and the chemical and volume control system are active safety-related valves that are designed, qualified, inspected and tested for the isolation requirements. The isolation valves between the reactor coolant system and chemical and volume control system are designed and qualified for design conditions that include closing against blowdown flow with full system differential pressure. These valves are qualified for adverse seismic and environmental conditions. The valves are subject to inservice testing including operability testing.

The potential for release of activity from a break or leak in the chemical and volume control system is minimized by the location of the purification subsystem inside containment and the design and test of the isolation valves. Chemical and volume control system leakage inside

containment is detectable by the reactor control leak detection function as potential reactor coolant pressure boundary leakage. This leakage must be identified before the reactor coolant leak limit is reached. The nonsafety-related classification of the system does not impact the need to identify the source of a leak inside containment.

5.2.2 Overpressure Protection

Reactor coolant system and steam system overpressure protection during power operation are provided by the pressurizer safety valves and the steam generator safety valves, in conjunction with the action of the reactor protection system. Combinations of these systems provide compliance with the overpressure protection requirements of the ASME Boiler and Pressure Vessel Code, Section III, Paragraphs NB-7300 and NC-7300, for pressurized water reactor systems.

Low temperature overpressure protection is provided by a relief valve in the suction line of the normal residual heat removal (RNS) system. The sizing and use of the relief valve for low temperature overpressure protection is consistent with the guidelines of Branch Technical Position RSB 5-2.

5.2.2.1 Design Bases

Overpressure protection during power operation is provided for the reactor coolant system by the pressurizer safety valves. This protection is afforded for the following events to envelop those credible events that could lead to overpressure of the reactor coolant system if adequate overpressure protection were not provided:

- Loss of electrical load and/or turbine trip
- Uncontrolled rod withdrawal at power
- Loss of reactor coolant flow
- Loss of normal feedwater
- Loss of offsite power to the station auxiliaries

The sizing of the pressurizer safety valves is based on the analysis of a complete loss of steam flow to the turbine, with the reactor operating at 102 percent of rated power. In this analysis, feedwater flow is also assumed to be lost. No credit is taken for operation of the pressurizer level control system, pressurizer spray system, rod control system, steam dump system, or steamline power-operated relief valves. The reactor is maintained at full power (no credit for direct reactor trip on turbine trip and for reactivity feedback effects), and steam relief through the steam generator safety valves is considered. The total pressurizer safety valve capacity is required to be at least as large as the maximum surge rate into the pressurizer during this transient.

This sizing procedure results in a safety valve capacity well in excess of the capacity required to prevent exceeding 110 percent of system design pressure for the events previously listed. The discharge of the safety valve is routed through a rupture disk to containment atmosphere. The rupture disk is to contain leakage past the valve. The rupture disk pressure rating is substantially less than the set pressure of the safety valve. See subsection 5.4.11 for additional information on

the safety valve discharge system. Subsection 5.4.5 describes the connection of the safety valves to the pressurizer.

Administrative controls and plant procedures aid in controlling reactor coolant system pressure during low-temperature operation. Normal plant operating procedures maximize the use of a steam or gas bubble in the pressurizer during periods of low pressure, low-temperature operation. For those low-temperature modes of operation when operation with a water solid pressurizer is possible, a relief valve in the residual heat removal system provides low-temperature overpressure protection for the reactor coolant system. The valve is sized to prevent overpressure during the following credible events with a water-solid pressurizer:

- Makeup/letdown flow mismatch
- Inadvertent actuation of the pressurizer heaters
- Loss of residual heat removal with reactor coolant system heatup due to decay heat and pump heat
- Inadvertent start of one reactor coolant pump
- Inadvertent hydrogen addition

Of those events the makeup/letdown flow mismatch is the limiting mass input condition. Inadvertent start of an inactive reactor coolant pump is the limiting heat input condition to size the relief valve. The flow rate postulated for mass input condition is based on the flow from two makeup pumps at the set pressure of the relief valve. The heat input condition is based on a 50-degree temperature difference between the reactor coolant system and the steam generator secondary side.

The set pressure for the normal residual heat removal system relief valve is established based on the lower value of the normal residual heat removal system design pressure and the low-temperature pressure limit for the reactor vessel based on ASME Code, Section III, Appendix G, analyses. The pressure-temperature limits for the reactor vessel, based on expected material properties and the vessel design, are discussed in subsection 5.3.3.

The capacity of the residual heat removal relief valve can maintain the pressure in the reactor coolant system and the residual heat removal system to a pressure less than the lesser of 110 percent of the design pressure of the normal residual heat removal system or the pressure limit from the Appendix G analyses for the limiting event.

Overpressure protection for the steam system is provided by steam generator safety valves. The capacity of the steam system safety valves limits steam system pressure to less than 110 percent of the steam generator shell side design pressure. See Section 10.3 for details.

Section 10.3 discusses the steam generator relief valves and connecting piping.

5.2.2.2 Design Evaluation

The relief capacities of the pressurizer safety valves, steam generator safety valves, and the normal residual heat removal system relief valve are determined from the postulated overpressure transient conditions in conjunction with the action of the reactor protection system. An overpressure protection report is prepared according to Article NB-7300 of Section III of the ASME Code. WCAP-7907 (Reference 1) describes the analytical model used in the analysis of the overpressure protection system and the basis for its validity.

Chapter 15 includes a design description of certain initiating events and describes assumptions made, method of analysis, conclusions, and the predicted response of the AP1000 to those events. The performance characteristics of the pressurizer safety valves are included in the analysis of the response. The incidents evaluated include postulated accidents not included in the compilation of credible events used for valve sizing purposes.

Subsection 5.4.9 discusses the capacities of the pressurizer safety valves and residual heat removal system relief valve used for low temperature overpressure protection. The setpoints and reactor trip signals which occur during operational overpressure transients are discussed in subsection 5.4.5. With the current AP1000 pressure-temperature limits (subsection 5.3.3), the set pressure for the relief valve in the normal residual heat removal system is based on a sizing analysis performed to prevent the reactor coolant system pressure from exceeding the applicable low temperature pressure limit for the reactor vessel based on ASME Code, Section III, Appendix G. The limiting mass and energy input transients are assumed for the sizing analysis.

5.2.2.3 Piping and Instrumentation Diagrams

The connection of the pressurizer safety valves to the pressurizer is incorporated into the pressurizer safety and relief valve module and is discussed in subsection 5.4.9. The pressurizer safety and relief valve module configuration appears in the piping and instrumentation drawing for the reactor coolant system (Figure 5.1-5). The normal residual heat removal system (subsection 5.4.7) incorporates the relief valve for low-temperature overpressure protection. The valves which isolate the normal residual heat removal system from the reactor coolant system do not have an autoclosure interlock. Figure 5.4-6 shows a simplified sketch of the normal residual heat removal system. Figure 5.4-7 shows the piping and instrumentation drawing for the residual heat removal system.

Section 10.3 discusses the safety valves for the main steam system. Figure 10.3.2-1 shows the piping and instrumentation drawing for the main steam system.

5.2.2.4 Equipment and Component Description

Subsection 5.4.9 discusses the design and design parameters for the safety valves providing operating and low-temperature overpressure protection. The pressurizer safety valves are ASME Boiler and Pressure Vessel Code Class 1 components. These valves are tested and analyzed using the design transients, loading conditions, seismic considerations, and stress limits for Class 1 components as described in subsections 3.9.1, 3.9.2, and 3.9.3.

The relief valve included in the normal residual heat removal system provides containment boundary function since it is connected to the piping between the containment isolation valves for the system. Containment isolation requirements are discussed in subsection 6.2.3. Based on the containment boundary function, the relief valve is an ASME Code Class 2 component and is analyzed to the appropriate requirements.

In addition to the testing and analysis required for ASME Code requirements, the pressurizer safety valves are of a type which has been verified to operate during normal operation, anticipated transients, and postulated accident conditions. The verification program (Reference 2) was established by the Electric Power Research Institute to address the requirements of 10 CFR 50.34 (f)(2)(x). These requirements do not apply to relief valves of the size and type represented by the relief valve on the normal residual heat removal system.

Section 10.3 discusses the equipment and components that provide the main steam system overpressure protection.

5.2.2.5 Mounting of Pressure Relief Devices

Subsection 5.4.9 describes the design and installation of the pressure relief devices for the reactor coolant system. Section 3.9 describes the design basis for the assumed loads for the primary- and secondary-side pressure relief devices. Subsection 10.3.2, discusses the main steam safety valves and the power-operated atmospheric steam relief valves.

5.2.2.6 Applicable Codes and Classification

The requirements of the ASME Boiler and Pressure Vessel Code, Section III, Paragraphs NB-7300 (Overpressure Protection Report) and NC-7300 (Overpressure Protection Analysis), are met.

Piping, valves, and associated equipment used for overpressure protection are classified according to the classification system discussed in subsection 3.2.2. These safety-class designations are delineated in Table 3.2-3.

5.2.2.7 Material Specifications

See subsection 5.2.3 for the material specifications for the pressurizer safety valves. The piping in the pressurizer safety and relief valve module up to the safety valve is considered reactor coolant system. See subsection 5.2.3 for material specifications. The discharge piping is austenitic stainless steel. Subsection 5.4.7 specifies the materials used in the normal residual heat removal system.

5.2.2.8 Process Instrumentation

Each pressurizer safety valve discharge line incorporates a main control room temperature indicator and alarm to notify the operator of steam discharge due to either leakage or actual valve operation.

5.2.2.9 System Reliability

ASME Code safety valves and relief valves have demonstrated a high degree of reliability over many years of service. The in-service inspection and testing required of safety valves and relief valves (subsections 3.9.6 and 5.4.8 and Section 6.6) provides assurance of continued reliability and conformance to setpoints. The assessment of reliability, availability, and maintainability which is done to evaluate the estimated availability for the AP1000 includes estimates for the contribution of safety valves and relief valves to unavailability. These estimates were based on experience for operating units.

5.2.2.10 Testing and Inspection

Subsections 3.9.6 and 5.4.8 and Section 6.6 discuss the preservice and in-service testing and inspection required for the safety valves and relief valves. The testing and inspection requirements are in conformance with industry standards, including Section XI of the ASME Code.

5.2.3 Reactor Coolant Pressure Boundary Materials

5.2.3.1 Materials Specifications

Table 5.2-1 lists material specifications used for the principal pressure-retaining applications in Class 1 primary components and reactor coolant system piping. Material specifications with grades, classes or types are included for the reactor vessel components, steam generator components, reactor coolant pump, pressurizer, core makeup tank, and the passive residual heat removal heat exchanger. Table 5.2-1 lists the application of nickel-chromium-iron alloys in the reactor coolant pressure boundary. The use of nickel-chromium-iron alloy in the reactor coolant pressure boundary is limited to Alloy 690, or its associated weld metals Alloys 52 and 152. Steam generator tubes use Alloy 690 in the thermally treated form. Nickel-chromium-iron alloys are used where corrosion resistance of the alloy is an important consideration and where the use of nickel-chromium-iron alloy is the choice because of the coefficient of thermal expansion. Subsection 5.4.3 defines reactor coolant piping. See subsection 4.5.2 for material specifications used for the core support structures and reactor internals. See appropriate sections for internals of other components. Engineered safeguards features materials are included in subsection 6.1.1. The nonsafety-related portion of the chemical and volume control system inside containment in contact with reactor coolant is constructed of or clad with corrosion resistant material such as Type 304 or Type 316 stainless steel or material with equivalent corrosion resistance. The materials are compatible with the reactor coolant. The nonsafety-related portion of the chemical and volume control system is not required to conform to the process requirements outlined below.

Table 5.2-1 material specifications are the materials used in the AP1000 reactor coolant pressure boundary. The materials used in the reactor coolant pressure boundary conform to the applicable ASME Code rules. Cast austenitic stainless steel does not exceed a ferrite content of 20 FN. Calculation of ferrite content is based on Hull’s equivalent factors.

The welding materials used for joining the ferritic base materials of the reactor coolant pressure boundary conform to or are equivalent to ASME Material Specifications SFA 5.5, 5.23, and 5.28. They are qualified to the requirements of the ASME Code, Section III.

The welding materials used for joining the austenitic stainless steel base materials of the reactor coolant pressure boundary conform to ASME Material Specifications SFA 5.4 and 5.9. They are qualified to the requirements of the ASME Code, 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 the ASME Code, Section III.

The fabrication and installation specifications for partial penetration welds with Alloy 52/152, within the ASME Class 1 reactor coolant pressure boundary, require successive dye penetrant examinations after the first pass and after every 1/4-inch of weld metal. The specifications for J-groove welds, which join ASME Class 1 reactor coolant pressure boundary penetrations require ultrasonic examination of the interface where the weld joins the penetration tube. The specifications for butt welds used for nozzle safe-end welds require these welds to be radiographically inspected. These weld specifications are applicable to the ASME Class 1 reactor coolant pressure boundary portions of the reactor vessel (Section 5.3), the reactor coolant pumps (subsection 5.4.1), the steam generators (subsection 5.4.2), the reactor coolant system piping (subsection 5.4.3), the pressurizer (subsection 5.4.5), the core makeup tanks (subsection 5.4.13), and the passive residual heat removal heat exchanger (subsection 5.4.14).

5.2.3.2 Compatibility with Reactor Coolant

5.2.3.2.1 Chemistry of Reactor Coolant

The reactor coolant system chemistry specifications conform to the recommendation of Regulatory Guide 1.44 and are shown in Table 5.2-2.

The reactor coolant system water chemistry is selected to minimize corrosion. Routinely scheduled analyses of the coolant chemical composition are performed to verify that the reactor coolant chemistry meets the specifications. Other additions, such as those to reduce activity transport and deposition, may be added to the system.

The chemical and volume control system (CVS) provides a means for adding chemicals to the reactor coolant system. The chemicals perform the following functions:

- Control the pH of the coolant during prestartup testing and subsequent operation
- Scavenge oxygen from the coolant during heatup
- Control radiolysis reactions involving hydrogen, oxygen, and nitrogen during power operations following startup

Table 5.2-2 shows the normal limits for chemical additives and reactor coolant impurities for power operation.

The pH control chemical is lithium hydroxide monohydrate, enriched in the lithium-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/nickel-chromium-iron systems. In addition, lithium-7 is produced in solution from the neutron irradiation of the dissolved boron in the coolant. The lithium-7 hydroxide is introduced into the reactor coolant system via the charging flow. The concentration of lithium-7 hydroxide in the reactor coolant system is maintained in the range specified for pH control.

During reactor startup from the cold condition, hydrazine is used as an oxygen-scavenging agent. The hydrazine solution is introduced into the reactor coolant system in the same manner as described 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 reacts with oxygen introduced into the reactor coolant system by the radiolysis effect of radiation on molecules. Hydrogen makeup is supplied to the reactor coolant system by direct injection of high pressure gaseous hydrogen, which can be adjusted to provide the correct equilibrium hydrogen concentration. Subsection 1.9.1 indicates the degree of conformance with Regulatory Guide 1.44, "Control of the Use of Sensitized Stainless Steel."

Boron, in the chemical form of boric acid, is added to the reactor coolant system for long-term reactivity control of the core.

Suspended solid (corrosion product particulates) and other impurity concentrations are maintained below specified limits by controlling the chemical quality of makeup water and chemical additives and by purification of the reactor coolant through the chemical and volume control system.

5.2.3.2.2 Compatibility of Construction Materials with Reactor Coolant

Ferritic low-alloy and carbon steels used in principal pressure-retaining applications have corrosion-resistant cladding on surfaces exposed to the reactor coolant. The corrosion resistance of the 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. These clad materials may be subjected to the ASME Code-required postweld heat treatment for ferritic base materials.

Ferritic low-alloy and carbon steel nozzles have safe ends of stainless steel-wrought materials welded to nickel-chromium-iron alloy-weld metal F-number 43 buttering. The safe end is welded to the F 43 buttering after completion of postweld heat treatment of the buttering when the nozzle is larger than a 4-inch nominal inside diameter and/or the wall thickness is greater than 0.531 inch.

Austenitic stainless steel and nickel-chromium-iron alloy base materials with primary pressure-retaining applications are used in the solution-annealed or thermally treated conditions. These heat treatments are as required by the material specifications.

During later fabrications, 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 resolution-annealing heat treatment.

Components using stainless steel sensitized in the manner expected during component fabrication and installation operate satisfactorily under normal plant chemistry conditions in pressurized water reactor (PWR) systems because chlorides, fluorides, and oxygen are controlled to very low levels. Subsection 1.9.1 indicates the degree of conformance with Regulatory Guide 1.44, "Control of the Use of Sensitized Stainless Steel."

Hardfacing material in contact with reactor coolant is primarily a qualified low or zero cobalt alloy equivalent to Stellite-6. The use of cobalt base alloy is minimized. Low or zero cobalt alloys used for hardfacing or other applications where cobalt alloys have been previously used are qualified using wear and corrosion tests. The corrosion tests qualify the corrosion resistance of the alloy in reactor coolant. Cobalt free wear resistant alloys considered for this application include those developed and qualified in nuclear industry programs.

5.2.3.2.3 Compatibility with External Insulation and Environmental Atmosphere

In general, materials that are used in principal pressure-retaining applications and 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 reactor coolant pressure boundary is reflective stainless steel-type.

The compounded materials in the form of blocks, boards, cloths, tapes, adhesives, cements, etc., are silicated to provide protection of austenitic stainless steels against stress corrosion that may result from accidental wetting of the insulation by spillage, minor leakage, or other contamination from the environmental atmosphere. Subsection 1.9.1 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 considered possible based on service experience (such as valve packing, pump seals, etc.), only materials compatible with the coolant are used. Table 5.2-1 shows examples. Ferritic materials exposed to coolant leakage can be readily observed as part of the inservice visual and/or nondestructive inspection program to confirm 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

The fracture toughness properties of the reactor coolant pressure boundary components meet the requirements of the ASME Code, Section III, Subarticle NB-2300. Those portions of the reactor coolant pressure boundary that meet the requirements of ASME Code, Section III, Class 2 per the criteria of 10 CFR 50.55a, meet the fracture toughness requirements of the ASME Code, Section III, Subarticle NC-2300. The fracture toughness properties of the reactor coolant pressure boundary components also meet the requirements of Appendix G of 10 CFR 50.

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

Limiting steam generator and pressurizer reference temperatures for a nil ductility transition (RT_{NDT}) temperatures are guaranteed at 10°F for the base materials and the weldments.

These materials meet the 50-foot-pound absorbed energy and 35-mils lateral expansion requirements of the ASME Code, Section III, at 70°F. The actual results of these tests are provided in the ASME material data reports which are supplied for each component and submitted to the owner at the time of shipment of the component.

Temperature instruments and Charpy impact test machines are calibrated 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 the 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 reactor coolant pressure boundary. WCAP-9292 (Reference 3) documents the program results.

5.2.3.3.2 Control of Welding

Welding is conducted using 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 according to ASME Code requirements.

The practices for storing and handling welding electrodes and fluxes comply with ASME Code, Section III, Paragraphs NB-2400 and NB-4400.

Subsection 1.9.1 indicates the degree of conformance of the ferritic materials components of the reactor coolant pressure boundary with Regulatory Guides 1.31, "Control of Ferrite Content in Stainless Steel Welds"; 1.34, "Control of Electroslag Weld Properties"; 1.43, "Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components"; 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

Subsections 5.2.3.4.1 through 5.2.3.4.5 address Regulatory Guide 1.44, "Control of the Use of Sensitized Stainless Steel," and present the methods and controls to avoid sensitization and to prevent intergranular attack (IGA) of austenitic stainless steel components. Also, subsection 1.9.1 indicates the degree of conformance with Regulatory Guide 1.44.

5.2.3.4.1 Cleaning and Contamination Protection Procedures

Austenitic stainless steel materials used in the fabrication, installation, and testing of nuclear steam supply components and systems are handled, protected, stored, and cleaned according to recognized, accepted methods designed to minimize contamination that could lead to stress corrosion cracking. The procedures covering these controls are stipulated in process

specifications. Tools used in abrasive work operations on austenitic stainless steel, such as grinding or wire brushing, do not contain and are not contaminated with ferritic carbon steel or other materials that could contribute to intergranular cracking or stress-corrosion cracking.

These process specifications supplement the equipment specifications and purchase order requirements of every individual austenitic stainless steel component or system procured for the AP1000, regardless of the ASME Code classification.

The process specifications define these requirements and follow the guidance of ASME NQA-2.

Subsection 1.9.1 indicates the degree of conformance of the austenitic stainless steel components of the reactor coolant pressure boundary 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 5.2-1 are used in the final heat-treated condition required by the respective ASME Code, Section II, materials specification for the particular type or grade of alloy.

5.2.3.4.3 Material Testing Program

Austenitic stainless steel materials of product forms with simple shapes need not be corrosion-tested provided that the solution heat treatment is followed by water quenching. Simple shapes are defined as plates, sheets, bars, pipe, and tubes, as well as forgings, fittings, and other shaped products that do not have inaccessible cavities or chambers that would preclude rapid cooling when water-quenched. This characterization of cavities or chambers as inaccessible is in relation to the entry of water during quenching and is not a determination of the component accessibility for inservice inspection.

When testing is required, the tests are performed according to a process specification following the guidelines of ASTM A 262, Practice A or E.

5.2.3.4.4 Prevention of Intergranular Attack of Unstabilized Austenitic Stainless Steels

Unstabilized stainless steels can be subject to intergranular attack if the steels are sensitized, if certain species are present, such as chlorides and oxygen, and if they are exposed to a stressed condition. In the reactor coolant system, reliance is placed on the elimination or avoidance of these conditions. This is accomplished by the following:

- Control of primary water chemistry to provide a benign environment
- Use of materials in the final heat-treated condition and the prohibition of subsequent heat treatments from 800°F to 1500°F
- Control of welding processes and procedures to avoid heat-affected zone sensitization

- Confirmation that the welding procedures used for the manufacture of components in the primary pressure boundary and the reactor internals do not result in the sensitization of heat-affected zones

Further information on each of these steps is provided in the following paragraphs.

The water chemistry in the reactor coolant system is controlled to prevent the intrusion of aggressive elements. In particular, the maximum permissible oxygen and chloride concentrations are 0.005 ppm and 0.15 ppm, respectively. Table 5.2-2 lists the recommended reactor coolant water chemistry specifications.

The precautions taken to prevent the intrusion of chlorides into the system during fabrication, shipping, and storage are stipulated in the appropriate process specifications. 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-term exposure of severely sensitized stainless steels to reactor coolant environments in early Westinghouse pressurized water reactors has not resulted in any sign of intergranular attack. WCAP-7477 (Reference 4) describes the laboratory experimental findings and reactor operating experience. The additional years of operations since Reference 4 was issued have provided further confirmation of the earlier conclusions that severely sensitized stainless steels do not undergo any intergranular attack in Westinghouse pressurized water reactor coolant environments.

Although there is no evidence that pressurized water reactor coolant water attacks sensitized stainless steels, it is good metallurgical practice to avoid the use of sensitized stainless steels in the reactor coolant system components.

Accordingly, measures are taken to prohibit the use of sensitized stainless steels and to prevent sensitization during component fabrication. The wrought austenitic stainless steel stock used in the reactor coolant pressure boundary is used in one of the following conditions:

- Solution-annealed and water-quenched

- Solution-annealed and cooled through the sensitization temperature range within less than about 5 minutes

Westinghouse has verified that these practices will prevent sensitization by performing corrosion tests on wrought material as it was received.

The heat-affected zones of welded components must, of necessity, be heated into the sensitization temperature range (800°F to 1500°F). However, severe sensitization (that is, continuous grain boundary precipitates of chromium carbide, with adjacent chromium depletion) can be avoided by controlling welding parameters and welding processes. The heat input and associated cooling rate through the carbide precipitation range are of primary importance. Westinghouse has demonstrated this by corrosion-testing a number of weldments.

The heat input in austenitic pressure boundary weldments is controlled by the following:

- Limiting the maximum interpass temperature to 350°F
- Exercising approval rights on welding procedures
- Requiring qualification of processes

5.2.3.4.5 Retesting Unstabilized Austenitic Stainless Steels Exposed to Sensitization Temperatures

If during the course of fabrication, steel is inadvertently exposed to the sensitization temperature range, the material may be tested according to a process specification, following the guidelines of ASTM A 262, to verify that it is not susceptible to intergranular attack. Testing is not required for the following:

- Cast metal or weld metal with a ferrite content of 5 percent or more
- Material with a carbon content of 0.03 percent or less
- Material exposed to special processing, provided the following:
  - Processing is properly controlled to develop a uniform product
  - Adequate documentation exists of service experience and/or test data to demonstrate that the processing will not result in increased susceptibility to intergranular attack

If such material is not verified to be not susceptible to intergranular attack, the material is resolution-annealed and water-quenched or rejected.

5.2.3.4.6 Control of Welding

The following paragraphs address Regulatory Guide 1.31, "Control of Ferrite Content in Stainless Steel Weld Metal." They 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.

Also, it has been well documented that delta ferrite is one of the mechanisms for reducing the susceptibility of stainless steel welds to hot cracking. The minimum delta ferrite level below which the material will be prone to hot cracking lies between 0 and 3 percent delta ferrite.

The following paragraphs discuss welding processes used to join stainless steel parts in components designed, fabricated, or stamped according to the ASME Code, Section III, Classes 1 and 2, and core support components. Delta ferrite control is appropriate for the preceding welding requirements, except where no filler metal is used or where such control is not applicable, such as the following: electron beam welding; autogenous gas shielded tungsten arc welding; explosive welding; welding using fully austenitic welding materials.

The fabrication and installation specifications require welding procedures and welder qualification according to Section III of the ASME Code. They also include the delta ferrite determinations for the austenitic stainless steel welding materials used for welding qualification testing and for production processing.

Specifically, the undiluted weld deposits of the "starting" welding materials must contain at least 5 percent delta ferrite. (The equivalent ferrite number may be substituted for percent delta ferrite.) This is determined by chemical analysis and calculation using the appropriate weld metal constitution diagrams in Section III of the ASME Code or magnetic measurement by calibrated instruments.

When new welding procedure qualification tests are evaluated for these applications, including repair welding of raw materials, they are performed according to the requirements of Sections III and IX of the ASME Code.

The results of the destructive and nondestructive tests are recorded in the procedure qualification record, in addition to the information required by Section III of the ASME Code.

The welding materials used for fabrication and installation welds of austenitic stainless steel materials and components meet the requirements of Section III of the ASME Code. For applications using austenitic stainless steel welding material, the material conforms to ASME weld metal analysis A-8, Type 308, 308L, 316, or 316L.

Bare weld filler metal, including consumable inserts, used in inert gas welding processes conforms to ASME SFA 5.9. The metal is procured to contain not less than 5 FN or more than 13 FN delta ferrite according to Section III of the ASME Code. Weld filler metal materials used in flux-shielded welding processes conform to ASME SFA 5.4 or 5.9. They are procured in a wire-flux combination to be capable of providing not less than 5 FN or more than 13 FN delta ferrite in the deposit, according to Section III of the ASME Code.

Welding materials are tested using the welding energy inputs employed in production welding.

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

- Quality assurance audit, including calibration of gauges and instruments
- Identification of welding materials
- Welder and procedure qualifications
- Availability and use of approved welding and heat-treating procedures
- 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 of the ASME Code rules.

To verify the reliability of these controls, Westinghouse has completed a delta ferrite verification program, described in WCAP-8324-A (Reference 5). This program has been approved as a valid approach to verify the Westinghouse hypothesis and is considered an acceptable alternative for conformance with the NRC 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 WCAP-8324-A (Reference 5), are summarized in WCAP-8693 (Reference 6).

Subsection 1.9.1 indicates the degree of conformance of the austenitic stainless steel components of the reactor coolant pressure boundary with Regulatory Guides 1.34, "Control of Electroslag Weld Properties," and 1.71, "Welder Qualification for Areas of Limited Accessibility."

5.2.3.4.7 Control of Cold Work in Austenitic Stainless Steels

The use of cold worked austenitic stainless steels is limited to small parts including pins and fasteners where proven alternatives are not available and where cold worked material has been used successfully in similar applications. Cold work control of austenitic stainless steels in pressure boundary applications is provided by limiting the hardness of austenitic stainless steel raw material and controlling the hardness during fabrication by process control of bending, cold forming, straightening or other similar operation. Grinding of material in contact with reactor coolant is controlled by procedures. Ground surfaces are finished with successively finer grit sizes to remove the bulk of cold worked material.

5.2.3.5 Threaded Fastener Lubricants

The lubricants to be used on threaded fasteners which maintain pressure boundary integrity in the reactor coolant and related systems and in the steam, feed, and condensate systems; threaded fasteners used inside those systems; and threaded fasteners used in component structural support for those systems are specified in the design specification. Field selection of thread lubricants is not permitted. The thread lubricants are selected based on experience and test data which show them to be effective, but not to cause or accelerate corrosion of the fastener. Where leak sealants are used on threaded fasteners or can be in contact with the fastener in service, their selection is based on satisfactory experience or test data. Selection considers possible adverse interaction between sealants and lubricants. Lubricants containing molybdenum sulphide are prohibited.

5.2.4 Inservice Inspection and Testing of Class 1 Components

Preservice and inservice inspection and testing of ASME Code Class 1 pressure-retaining components (including vessels, piping, pumps, valves, bolting, and supports) within the reactor coolant pressure boundary are performed in accordance with Section XI of the ASME Code including addenda according to 10 CFR 50.55a(g). This includes all ASME Code Section XI mandatory appendices.

The specific edition and addenda of the Code used to determine the requirements for the inspection and testing plan for the initial and subsequent inspection intervals is to be delineated in

the inspection program. The Code includes requirements for system pressure tests and functional tests for active components. The requirements for system pressure tests are defined in Section XI, IWA-5000. These tests verify the pressure boundary integrity in conjunction with inservice inspection. Section 6.6 discusses Classes 2 and 3 component examinations.

Subsection 3.9.6 discusses the in-service functional testing of valves for operational readiness. Since none of the pumps in the AP1000 are required to perform an active safety function, the operational readiness test program for pumps is controlled administratively.

In conformance with ASME Code and NRC requirements, the preparation of inspection and testing programs is the responsibility of the combined license applicant of each AP1000. A preservice inspection program (nondestructive examination) and a preservice test program for valves for the AP1000 will be developed and submitted to the NRC. The in-service inspection program and in-service test program will be submitted to the NRC by the combined license applicant. These programs will comply with applicable in-service inspection provisions of 10 CFR 50.55a(b)(2).

The preservice programs provide details of areas subject to examination, as well as the method and extent of preservice examinations. In-service programs detail the areas subject to examination and the method, extent, and frequency of examinations. Additionally, component supports and snubber testing requirements are included in the inspection programs.

5.2.4.1 System Boundary Subject to Inspection

ASME Code Class 1 components (including vessels, piping, pumps, valves, bolting, and supports) are designated AP1000 equipment Class A (see subsection 3.2.2). Class 1 pressure-retaining components and their specific boundaries are included in the equipment designation list and the line designation list. Both of these lists are contained in the inspection programs.

5.2.4.2 Arrangement and Inspectability

ASME Code Class 1 components are designed so that access is provided in the installed condition for visual, surface, and volumetric examinations specified by the ASME Code Section XI (1998 Edition) and mandatory appendices. Design provisions, in accordance with Section XI, Article IWA-1500, are incorporated in the design processes for Class 1 components.

The AP1000 design activity includes a design for inspectability program. The goal of this program is to provide for the inspectability access and conformance of component design with available inspection equipment and techniques. Factors such as examination requirements, examination techniques, accessibility, component geometry and material selection are used in evaluating component designs. Examination requirements and examination techniques are defined by inservice inspection personnel. Inservice inspection review as part of the design process provides component designs that conform to inspection requirements and establishes recommendations for enhanced inspections.

Considerable experience is utilized in designing, locating, and supporting pressure-retaining components to permit preservice and in-service inspection required by Section XI of the ASME Code. Factors such as examination requirements, examination techniques, accessibility,

component geometry, and material selections aid in establishing the designs. The inspection design goals are to eliminate uninspectable components, reduce occupational radiation exposure, reduce inspections times, allow state-of-the-art inspection system, and enhance flaw detection and the reliability of flaw characterization.

As one example of component geometry that reduces inspection requirements, the reactor pressure vessel has no longitudinal welds requiring in-service inspection. No Quality Group A (ASME Code Class 1) components require in-service inspection during reactor operation.

Removable insulation and shielding are provided on those piping systems requiring volumetric and surface examination. Removable hangers and pipe whip restraints are provided as necessary and practical to facilitate inservice inspection. Working platforms are provided in areas requiring inspection and servicing of pumps and valves. Permanent or temporary working platforms, scaffolding, and ladders facilitate access to piping and component welds. The components and welds requiring in-service inspection allow for the application of the required in-service inspection methods. Such design features include sufficient clearances for personnel and equipment, maximized examination surface distances, two-sided access, favorable materials, weld-joint simplicity, elimination of geometrical interferences, and proper weld surface preparation.

Some of the ASME Class 1 components are included in modules fabricated offsite and shipped to the site. (See subsection 3.9.1.5.) The modules are designed and engineered to provide access for in-service inspection and maintenance activities. The attention to detail engineered into the modules before construction provides the accessibility for inspection and maintenance. Relief from Section XI requirements should not be required for Class 1 pressure retaining components in the AP1000. Future unanticipated changes in the ASME Code, Section XI requirements could, however, necessitate relief requests. Relief from the inspection requirements of ASME Code, Section XI will be requested when full compliance is not practical according to the requirements of 10 CFR 50.55a(g)(5)(iv). In such cases, specific information will be provided which identifies the applicable Code requirements, justification for the relief request, and the inspection method to be used as an alternative.

Space is provided to handle and store insulation, structural members, shielding, and other materials related to the inspection. Suitable hoists and other handling equipment, lighting, and sources of power for inspection equipment are installed. The integrated head package provides for access to inspect the reactor vessel head and the weld of the control rod drive mechanisms to the reactor vessel head. Closure studs, nuts, and washers are removed to a dry location for direct inspection.

5.2.4.3 Examination Techniques and Procedures

The visual, surface, and volumetric examination techniques and procedures agree with the requirements of Subarticle IWA-2200 and Table IWB-2500-1 of the ASME Code, Section XI. Qualification of the ultrasonic inspection equipment, personnel and procedures is in compliance with Appendix VII of the ASME Code, Section XI. The liquid penetrant method or the magnetic particle method is used for surface examinations. Radiography, ultrasonic, or eddy current techniques (manual or remote) are used for volumetric examinations.

The reactor vessel is designed so that the reactor pressure vessel (RPV) inspections can be performed primarily from the vessel internal surfaces. These inspections can be done remotely using existing inspection tool designs to minimize occupational radiation exposure and to facilitate the inspections. Access is also available for the application of inspection techniques from the outside of the complete reactor pressure vessel. Reactor pressure vessel welds are examined to meet the requirements of Regulatory Guide 1.150 as defined in subsection 1.9.1.

5.2.4.4 Inspection Intervals

Inspection intervals are established as defined in Subarticles IWA-2400 and IWB-2400 of the ASME Code, Section XI. The interval may be extended by as much as one year so that inspections are concurrent with plant outages. It is intended that in-service examinations be performed during normal plant outages such as refueling shutdowns or maintenance shutdowns occurring during the inspection interval.

5.2.4.5 Examination Categories and Requirements

The examination categories and requirements are established according to Subarticle IWB-2500 and Table IWB-2500-1 of the ASME Code, Section XI. The preservice examinations comply with IWB-2200.

5.2.4.6 Evaluation of Examination Results

Examination results are evaluated according to IWA-3000 and IWB-3000, with flaw indications according to IWB-3400 and Table IWB-3410-1. Repair procedures, if required, are according to IWB-4000 of the ASME Code, Section XI.

5.2.4.7 System Leakage and Hydrostatic Pressure Tests

System pressure tests comply with IWA-5000 and IWB-5000 of the ASME Code, Section XI. These system pressure tests are included in the design transients defined in Subsection 3.9.1. This subsection discusses the transients included in the evaluation of fatigue of Class 1 components due to cyclic loads.

5.2.5 Detection of Leakage Through Reactor Coolant Pressure Boundary

The reactor coolant pressure boundary (RCPB) leakage detection monitoring provides a means of detecting and to the extent practical, identifying the source and quantifying the reactor coolant leakage. The detection monitors perform the detection and monitoring function in conformance with the requirements of General Design Criteria 2 and 30 and the recommendations of Regulatory Guide 1.45. Leakage detection monitoring is also maintained in support of the use of leak-before-break criteria for high-energy pipe in containment. See subsection 3.6.3 for the application of leak-before-break criteria.

Leakage detection monitoring is accomplished using instrumentation and other components of several systems. Diverse measurement methods including level, flow, and radioactivity measurements are used for leak detection. The equipment classification for each of the systems and components used for leak detection is generally determined by the requirements and functions

of the system in which it is located. There is no requirement that leak detection and monitoring components be safety-related. See Figure 5.2-1 for the leak detection approach. The descriptions of the instrumentation and components used for leak detection and monitoring include information on the system.

To satisfy position 1 of Regulatory Guide 1.45, reactor coolant pressure boundary leakage is classified as either identified or unidentified leakage. Identified leakage includes:

- Leakage from closed systems such as reactor vessel seal or valve leaks that are captured and conducted to a collecting tank

- Leakage into auxiliary systems and secondary systems (intersystem leakage) (This leakage is considered to be part of the 10 gpm limit identified leakage in the bases of the technical specification 3.4.8. This additional leakage must be considered in the evaluation of the reactor coolant inventory balance.)

Other leakage is unidentified leakage.

5.2.5.1 Collection and Monitoring of Identified Leakage

Identified leakage other than intersystem leakage is collected in the reactor coolant drain tank. The reactor coolant drain tank is a closed tank located in the reactor cavity in the containment. The tank vent is piped to the gaseous radwaste system to prevent release of radioactive gas to the containment atmosphere. For positions 1 and 7 of Regulatory Guide 1.45, the liquid level in the reactor coolant drain tank and total flow pumped out of the reactor coolant drain tank are used to calculate the identified leakage rate. The identified leakage rate is automatically calculated by the plant computer. A leak as small as 0.1 gpm can be detected in one hour. The design leak of 10 gpm will be detected in less than a minute. These parameters are available in the main control room. The reactor coolant drain tank, pumps, and sensors are part of the liquid radwaste system. The following sections outline the various sources of identified leakage other than intersystem leakage.

5.2.5.1.1 Valve Stem Leakoff Collection

Valve stem leakoff connections are not provided in the AP1000.

5.2.5.1.2 Reactor Head Seal

The reactor vessel flange and head flange are sealed by two concentric seals. Seal leakage is detected by two leak-off connections: one between the inner and outer seal, and one outside the outer seal. These lines are combined in a header before being routed to the reactor coolant drain tank. An isolation valve is installed in the common line. During normal plant operation, the leak-off valves are aligned so that leakage across the inner seal drains to the reactor coolant drain tank.

A surface-mounted resistance temperature detector installed on the bottom of the common reactor vessel seal leak pipe provides an indication and high temperature alarm signal in the main control

room indicating the possibility of a reactor pressure vessel head seal leak. The temperature detector and drain line downstream of the isolation valve are part of the liquid radwaste system.

The reactor coolant pump closure flange is sealed with a welded canopy seal and does not require leak-off collection provisions.

Leakage from other flanges is discussed in subsection 5.2.5.3, Collection and Monitoring of Unidentified Leakage.

5.2.5.1.3 Pressurizer Safety Relief and Automatic Depressurization Valves

Temperature is sensed downstream of each pressurizer safety relief valve and each automatic depressurization valve mounted on the pressurizer by a resistance temperature detector on the discharge piping just downstream of each valve. High temperature indications (alarms in the main control room) identify a reduction of coolant inventory as a result of seat leakage through one of the valves. These detectors are part of the reactor coolant system. This leakage is drained to the reactor coolant drain tank during normal plant operation and vented to containment atmosphere or the in-containment refueling water storage tank during accident conditions. This identified leakage is measured by the change in level of the reactor coolant drain tank.

5.2.5.1.4 Other Leakage Sources

In the course of plant operation, various minor leaks of the reactor coolant pressure boundary may be detected by operating personnel. If these leaks can be subsequently observed, quantified, and routed to the containment sump, this leakage will be considered identified leakage.

5.2.5.2 Intersystem Leakage Detection

Substantial intersystem leakage from the reactor coolant pressure boundary to other systems is not expected. However, possible leakage points across passive barriers or valves and their detection methods are considered. In accordance with position 4 of Regulatory Guide 1.45, auxiliary systems connected to the reactor coolant pressure boundary incorporate design and administrative provisions that limit leakage. Leakage is detected by increasing auxiliary system level, temperature, flow, or pressure, by lifting the relief valves or increasing the values of monitored radiation in the auxiliary system.

The normal residual heat removal system and the chemical and volume control system, which are connected to the reactor coolant system, have potential for leakage past closed valves. For additional information on the control of reactor coolant leakage into these systems, see subsections 5.4.7 and 9.3.6 and the intersystem LOCA discussion in subsection 1.9.5.1.

5.2.5.2.1 Steam Generator Tubes

An important potential identified leakage path for reactor coolant is through the steam generator tubes into the secondary side of the steam generator. Identified leakage from the steam generator primary side is detected by one, or a combination, of the following:

- High condenser air removal discharge radioactivity, as monitored and alarmed by the turbine island vent discharge radiation monitor
- Steam generator secondary side radioactivity, as monitored and alarmed by the steam generator blowdown radiation monitor
- Secondary side radioactivity, as monitored and alarmed by the main steam line radiation monitors
- Radioactivity, boric acid, or conductivity in condensate as indicated by laboratory analysis

Details on the radiation monitors are provided in Section 11.5, Radiation Monitoring.

5.2.5.2.2 Component Cooling Water System

Leakage from the reactor coolant system to the component cooling water system is detected by the component cooling water system radiation monitor, by increasing surge tank level, by high flow downstream of selected components, or by some combination of the preceding. Refer to Section 11.5, Radiation Monitoring, and subsection 9.2.2, Component Cooling Water System.

5.2.5.2.3 Passive Residual Heat Removal Heat Exchanger Tubes

A potential identified leakage path for reactor coolant is through the passive residual heat removal heat exchanger into the in-containment refueling water storage tank. Identified leakage from the passive residual heat removal heat exchanger tubes is detected as follows:

- High temperature in the passive residual heat removal heat exchanger, as monitored and alarmed by temperature detectors in the heat exchanger inlet and outlet piping, alerts the operators to potential leakage. The location of these instruments is selected to provide early indication of leakage considering the potential for thermal stratification. The alarm setpoint is selected to provide early indication of leakage.
- The operator then closes the passive residual heat removal heat exchanger inlet isolation valve and observes the pressure indication inside the passive residual heat removal heat exchanger. If pressure remains at reactor coolant system pressure, then tube leakage is not present, and the high passive residual heat removal heat exchanger temperature is indicative of leakage through the outlet isolation valves.
- If the operator observes a reduction in pressure, then passive residual heat removal heat exchanger tube leakage is present. The operator then observes the change in the reactor coolant system inventory balance when the passive residual heat removal heat exchanger inlet isolation valve is closed. The difference in the reactor coolant system leakage when the isolation valve is closed identifies the passive residual heat removal heat exchanger tube leakage rate.

5.2.5.3 Collection and Monitoring of Unidentified Leakage

Position 3 of Regulator Guide 1.45 identifies three diverse methods of detecting unidentified leakage. AP1000 use two of these three and adds a third method. To detect unidentified leakage inside containment, the following diverse methods may be utilized to quantify and assist in locating the leakage:

- Containment Sump Level
- Reactor Coolant System Inventory Balance
- Containment Atmosphere Radiation

Other methods that can be employed to supplement the above methods include:

- Containment Atmosphere Pressure, Temperature, and Humidity
- Containment Water Level
- Visual Inspection

The reactor coolant system is an all-welded system, except for the connections on the pressurizer safety valves, reactor vessel head, explosively actuated fourth stage automatic depressurization system valves, pressurizer and steam generator manways, and reactor vessel head vent, which are flanged. During normal operation, variations in airborne radioactivity, containment pressure, temperature, or specific humidity above the normal level signify a possible increase in unidentified leakage rates and alert the plant operators that corrective action may be required. Similarly, increases in containment sump level signify an increase in unidentified leakage. The following sections outline the methods used to collect and monitor unidentified leakage.

These methods also allow for identification of main steam line leakage inside containment. The primary method of identifying steam line leakage is redundant containment sump level monitoring. A diverse backup method is provided by containment water level monitoring. The safety-related class 1E containment water level sensors use a different measuring process than the containment sump level sensors.

5.2.5.3.1 Containment Sump Level Monitor

In conformance with position 2 of Regulatory Guide 1.45, leakage from the reactor coolant pressure boundary and other components not otherwise identified inside the containment will condense and flow by gravity via the floor drains and other drains to the containment sump.

A leak in the primary system would result in reactor coolant flowing into the containment sump. Leakage is indicated by an increase in the sump level. The containment sump level is monitored by three seismic Category I level sensors. Position 6 of Regulatory Guide 1.45 requires two sensors. The third sensor is provided for redundancy in detecting main steam line leakage. The level sensors are powered from a safety-related Class 1E electrical source. These sensors remain functional when subjected to a safe shutdown earthquake in conformance with the guidance in Regulatory Guide 1.45. The containment sump level and sump total flow sensors located on the discharge of the sump pump are part of the liquid radwaste system.

Failure of two of the level sensors will still allow the calculation of a 0.5 gpm in-leakage rate within 1 hour. The data display and processing system (DDS) computes the leakage rate and the plant control system (PLS) provides an alarm in the main control room if the average change in leak rate for any given measurement period exceeds 0.5 gpm for unidentified leakage. The minimum detectable leak is 0.03 gpm. Unidentified leakage is the total leakage minus the identified leakage. The leakage rate algorithm subtracts the identified leakage directed to the sump.

To satisfy positions 2 and 5 of Regulatory Guide 1.45, the measurement interval must be long enough to permit the measurement loop to adequately detect the increase in level that would correspond to 0.5 gpm leak rate, and yet short enough to ensure that such a leak rate is detected within an hour. The measurement interval is less than or equal to 1 hour.

When the sump level increases to the high level setpoint, one of the sump pumps automatically starts to pump the accumulated liquid to the waste holdup tanks in the liquid radwaste system. The sump discharge flow is integrated and available for display in the control room, in accordance with position 7 of Regulatory Guide 1.45.

Procedures to identify the leakage source upon a change in the unidentified leakage rate into the sump include the following:

- Check for changes in containment atmosphere radiation monitor indications,
- Check for changes in containment humidity, pressure, and temperature,
- Check makeup rate to the reactor coolant system for abnormal increases,
- Perform an RCS inventory balance,
- Check for changes in water levels and other parameters in systems which could leak water into the containment, and
- Review records for maintenance operations which may have discharged water into the containment.

This procedure allows identification of main steam line leakage as well as RCS leakage.

5.2.5.3.2 Reactor Coolant System Inventory Balance

Reactor coolant system inventory monitoring provides an indication of system leakage. Net level change in the pressurizer is indicative of system leakage. Monitoring net makeup from the chemical and volume control system and net collected leakage provides an important method of obtaining information to establish a water inventory balance. An abnormal increase in makeup water requirements or a significant change in the water inventory balance can indicate increased system leakage.

The reactor coolant system inventory balance is a quantitative inventory or mass balance calculation. This approach allows determination of both the type and magnitude of leakage.

Steady-state operation is required to perform a proper inventory balance calculation. Steady-state is defined as stable reactor coolant system pressure, temperature, power level, pressurizer level, and reactor coolant drain tank and in-containment refueling water storage tank levels. The reactor coolant inventory balance is done on a periodic basis and when other indication and detection methods indicate a change in the leak rate. The minimum detectable leak is 0.13 gpm.

The mass balance involves isolating the reactor coolant system to the extent possible and observing the change in inventory which occurs over a known time period. This involves isolating the systems connected to the reactor coolant system. System inventory is determined by observing the level in the pressurizer. Compensation is provided for changes in plant conditions which affect water density. The change in the inventory determines the total reactor coolant system leak rate. Identified leakages are monitored (using the reactor coolant drain tank) to calculate a leakage rate and by monitoring the intersystem leakage. The unidentified leakage rate is then calculated by subtracting the identified leakage rate from the total reactor coolant system leakage rate.

Since the pressurizer inventory is controlled during normal plant operation through the level control system, the level in the pressurizer will be reasonably constant even if leakage exists. The mass contained in the pressurizer may fluctuate sufficiently, however, to have a significant effect on the calculated leak rate. The pressurizer mass calculation includes both the steam and water mass contributions.

Changes in the reactor coolant system mass inventory are a result of changes in liquid density. Liquid density is a strong function of temperature and a lesser function of pressure. A range of temperatures exists throughout the reactor coolant system all of which may vary over time. A simplified, but acceptably accurate, model for determining mass changes is to assume all of the reactor coolant system is at $T_{Average}$.

The inventory balance calculation is done by the data display and processing system with additional input from sensors in the protection and safety monitoring system, chemical and volume control system, and liquid radwaste system. The use of components and sensors in systems required for plant operation provides conformance with the regulatory guidance of position 6 in Regulatory Guide 1.45 that leak detection should be provided following seismic events that do not require plant shutdown.

5.2.5.3.3 Containment Atmosphere Radioactivity Monitor

Leakage from the reactor coolant pressure boundary will result in an increase in the radioactivity levels inside containment. The containment atmosphere is continuously monitored for airborne gaseous radioactivity. Air flow through the monitor is provided by the suction created by a vacuum pump. Gaseous N_{13}/F_{18} concentration monitors indicate radiation concentrations in the containment atmosphere.

N_{13} and F_{18} are neutron activation products which are proportional to power levels. An increase in activity inside containment would therefore indicate a leakage from the reactor coolant pressure boundary. Based on the concentration of N_{13}/F_{18} and the power level, reactor coolant pressure boundary leakage can be estimated.

The N_{13}/F_{18} monitor is seismic Category I. Conformance with the position 6 guidance of Regulatory Guide 1.45 that leak detection should be provided following seismic events that do not require plant shutdown is provided by the seismic Category I classification. Safety-related Class 1E power is not required since loss of power to the radiation monitor is not consistent with continuing operation following an earthquake.

The N_{13}/F_{18} monitor is operable when the plant is above 20-percent power, and can detect a 0.5 gpm leak within 1 hour when the plant is at full power.

Radioactivity concentration indication and alarms for loss of sample flow, high radiation, and loss of indication are provided. Sample collection connections permit sample collection for laboratory analysis. The radiation monitor can be calibrated during power operation.

5.2.5.3.4 Containment Pressure, Temperature and Humidity Monitors

Reactor coolant pressure boundary leakage increases containment pressure, temperature, and humidity, values available to the operator through the plant control system.

An increase in containment pressure is an indication of increased leakage or a high energy line break. Containment pressure is monitored by redundant Class 1E pressure transmitters. For additional discussion see subsection 6.2.2, Passive Containment Cooling System.

The containment average temperature is monitored using temperature instrumentation at the inlet to the containment fan cooler as an indication of increased leakage or a high energy line break. This instrumentation as well as temperature instruments within specific areas including steam generator areas, pressurizer area, and containment compartments are part of the containment recirculation cooling system.

An increase in the containment average temperature combined with an increase in containment pressure indicate increased leakage or a high energy line break. The individual compartment area temperatures can assist in identifying the location of the leak.

Containment humidity is monitored using temperature-compensated humidity detectors which determine the water-vapor content of the containment atmosphere. An increase in the containment atmosphere humidity indicates release of water vapor within the containment. The containment humidity monitors are part of the containment leak rate test system.

The humidity monitors supplement the containment sump level monitors and are most sensitive under conditions when there is no condensation. A rapid increase of humidity over the ambient value by more than 10 percent is indication of a probable leak.

Containment pressure, temperature and humidity can assist in identifying and locating a leak. They are not relied on to quantify a leak.

5.2.5.4 Safety Evaluation

Leak detection monitoring has no safety-related function. Therefore, the single failure criterion does not apply and there is no requirement for a nuclear safety evaluation. The containment sump

level monitors and the containment atmosphere monitor are seismic Category I. The components used to calculate reactor coolant system inventory balance are both safety-related and nonsafety-related components. The containment sump level monitors are powered from the Class 1E dc and UPS system (IDS). Measurement signals are processed by the data display and processing system and the plant control system (PLS).

5.2.5.5 Tests and Inspections

To satisfy position 8 of Regulatory Guide 1.45, periodic testing of leakage detection monitors verifies the operability and sensitivity of detector equipment. These tests include installation calibrations and alignments, periodic channel calibrations, functional tests, and channel checks in conformance with regulatory guidance.

5.2.5.6 Instrumentation Applications

The parameters tabulated below satisfy position 7 of Regulatory Guide 1.45 and are provided in the main control room to allow operating personnel to monitor for indications of reactor coolant pressure boundary leakage. The containment sump level, containment atmosphere radioactivity, reactor coolant system inventory balance, and the flow measurements are provided as gallon per minute leakage equivalent.

Parameter	System(s)	Alarm or Indication
Containment sump level and sump total flow	WLS	Both
Reactor coolant drain tank level and drain tank total flow	WLS	Both
Containment atmosphere radioactivity	PSS	Both
Reactor coolant system inventory balance parameters	PCS, PXS, RCS, VCS, WLS	Both
Containment humidity	VUS	Indication
Containment atmospheric pressure	PCS	Both
Containment atmosphere temperature	VCS	Both
Containment water level	PXS	Both(1)
Reactor vessel head seal leak temperature	WLS	Both
Pressurizer safety relief valve leakage temperature	RCS	Both
Steam generator blowdown radiation	BDS	Both
Turbine island vent discharge radiation	TDS	Both
Component cooling water radiation	CCS	Both

Parameter	System(s)	Alarm or Indication
Main steam line radiation	SGS	Both
Component cooling water surge tank level	CCS	Both

Note:
1. The containment water level instruments provide indication and alarm for identification of a 0.5 gpm leak within 3.5 days.

5.2.5.7 Technical Specification

Limits which satisfy position 9 of Regulatory Guide 1.45 for identified and unidentified reactor coolant leakage are identified in the technical specifications, Chapter 16. LCO 3.4.7 addresses RCS leakage limits. LCO 3.7.8 addresses main steam line leakage limits. LCO 3.4.9 addresses leak detection instrument requirements.

5.2.6 Combined License Information Items

5.2.6.1 ASME Code and Addenda

The Combined License applicant will address in its application the portions of later ASME Code editions and addenda to be used to construct components that will require NRC staff review and approval. The Combined License applicant will address consistency of the design with the construction practices (including inspection and examination methods) of the later ASME Code edition and addenda added as part of the Combined License application. The Combined License applicant will address the addition of ASME code cases approved subsequent to design certification.

5.2.6.2 Plant-Specific Inspection Program

The Combined License applicant will provide a plant-specific preservice inspection and inservice inspection program. The program will address reference to the edition and addenda of the ASME Code Section XI used for selecting components subject to examination, a description of the components exempt from examination by the applicable code, and drawings or other descriptive information used for the examination.

The preservice inspection program will include examinations of the reactor vessel closure head equivalent to those outlined in subsection 5.3.4.7.

The inservice inspection program will address the susceptibility calculations, inspection categorization, inspections of the reactor vessel closure head, and associated reports and notifications as defined in NRC Order EA-03-009, "Interim Inspection Requirements for Reactor Vessel Heads at PWRs" or NRC requirements that may supercede the Order.

The COL applicant will identify any areas of inspection required by Order EA-03-009, or required by subsequent NRC requirements that may supercede the Order, that the applicant will be unable

to perform or choose to perform an alternate. The applicant will submit to the NRC for review and approval a description of the proposed inspections to be performed, a description of any differences from the applicable NRC requirements, and an assessment of the acceptability of the inspection the applicant proposes to perform to address NRC requirements.

The inservice inspection program will also include provisions to ensure that boric acid corrosion does not degrade the reactor coolant pressure boundary.

5.2.7 References

1. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), and WCAP-7907-A (Nonproprietary), April 1984.

2. EPRI PWR Safety and Relief Valve Test Program, Safety and Relief Valve Test Report, Interim Report, April 1982.

3. Logsdon, W. A., Begley, J. A., and Gottshall, C. L., "Dynamic Fracture Toughness of ASME SA-508 Class 2a and ASME SA-533 Grade A Class 2 Base and Heat-Affected Zone Material and Applicable Weld Metals," WCAP-9292, March 1978.

4. Golik, M. A., "Sensitized Stainless Steel in Westinghouse PWR Nuclear Steam Supply Systems," WCAP-7477-L (Proprietary), March 1970, and WCAP-7735 (Nonproprietary), August 1971.

5. Enrietto, J. F., "Control of Delta Ferrite in Austenitic Stainless Steel Weldments," WCAP-8324-A, June 1975.

6. Enrietto, J. F., "Delta Ferrite in Production Austenitic Stainless Steel Weldments," WCAP-8693, January 1976.

Table 5.2-1 (Sheet 1 of 3)

REACTOR COOLANT PRESSURE BOUNDARY MATERIALS SPECIFICATIONS

Component	Material	Class, Grade, or Type
Reactor Vessel Components		
Head plates (other than core region)	SA-533 or SA-508	GR B, CL 1 or CL 3
Shell courses	SA-508	CL 3
Shell, flange, and nozzle forgings	SA-508	CL 3
Nozzle safe ends	SA-182	F316LN
Appurtenances to the control rod drive mechanism (CRDM)	SB-167 or SA-182	TP690 or F304LN, F316LN
Instrumentation tube appurtenances, upper head	SB-167 or SA-182, SA312, SA376	TP690 or F304LN, F316LN
Closure studs	SA-540	GR B23 or GR B24, CL 3
Monitor tubes and vent pipe	SA-312 or SA-376 or SB-166, SB-167	TP304LN, TP316LN or TP690
Cladding, buttering, and welds	SFA 5.4, 5.9, 5.11, and 5.14	308L, 309L, ENiCrFe-7, or ERNiCrFe-7
Pressure boundary welds	Low alloy steel	SFA 5.5, 5.23, 5.28
Steam Generator Components		
Pressure plates	SA-533	GR B, CL 1
Pressure forgings (including nozzles and tube sheet)	SA-508	CL 3a
Nozzle safe ends	SA-182	F316LN
Channel heads	SA-508	CL 3a
Tubes	SB-163	TP690TT
Cladding, buttering, and welds	SFA 5.4, 5.9, 5.11, and 5.14	308L, 309L, ENiCrFe-7, or ERNiCrFe-7
Pressure boundary welds	Low alloy steel	SFA 5.5, 5.23, 5.28
Manway studs/nuts	SA-193, SA-194	GR B7

Table 5.2-1 (Sheet 2 of 3)

REACTOR COOLANT PRESSURE BOUNDARY MATERIALS SPECIFICATIONS

Component	Material	Class, Grade, or Type
Pressurizer Components		
Pressure plates	SA-533	GR B, CL 1
Pressure forgings	SA-508	CL 3
Nozzle safe ends	SA-182	F316LN
Cladding, buttering, and welds	SFA 5.4, 5.9, 5.11, and 5.14	308L, 309L, ENiCrFe-7, or ERNiCrFe-7
Pressure boundary welds	Low alloy steel	SFA 5.5, 5.23, 5.28
Manway studs/nuts	SA-193, SA-194	GR B7
Reactor Coolant Pump		
Pressure forgings	SA-182 or SA-336	F304LN, F316LN
Pressure casting	SA-351 or SA-352	CF3A
Tube and pipe	SA-213; SA-376 or SA-312	TP304LN, TP316LN
Pressure plates	SA-240	304LN, 316LN
Closure bolting	SA-193 or SA-540	GR B7 or GR B24, CL 4
Pressure boundary welds	Low alloy steel	SFA 5.5, 5.23, 5.28
Reactor Coolant Piping		
Reactor coolant pipe	SA-376	TP304LN, TP316LN
Reactor coolant fittings, branch nozzles	SA-376, SA-182	TP304LN, TP316LN
Surge line	SA-376	TP304LN, TP316LN
RCP piping other than loop and surge line	SA-312 and SA-376	TP304LN, TP316LN
Pressure boundary welds	Low alloy steel	SFA 5.5, 5.23, 5.28
CRDM		
Latch housing	SA-336	F304LN, F316LN
Rod travel housing	SA-336	F304LN, F316LN
Welding materials	SFA 5.4 or 5.9	308L, 309L

Table 5.2-1 (Sheet 3 of 3)

REACTOR COOLANT PRESSURE BOUNDARY MATERIALS SPECIFICATIONS

Component	Material	Class, Grade, or Type
Valves		
Bodies	SA-182 or SA-351	F304LN, F316LN or CF3A
Bonnets	SA-182, SA-240 or SA-351	F304LN, F316LN, 304LN, 316LN or CF3A
Discs	SA-182, SA-564 or SA-351	F304LN, F316LN or GR 630 or CF3A
Stems	SA-479 or SA-564	F316, F316LN or GR 630
Pressure retaining bolting	SA-453 or SA-564	GR 660 or GR 630
Pressure retaining nuts	SA-453 or SA-194	GR 6 or TP410
Core Makeup Tank		
Pressure plates	SA-533 or SA-240	GR B, CL 1 or 304L, 304LN, 316L, 316LN
Pressure forgings	SA-508 or SA-182, SA-336	CL 3 or F304L, F316L
Cladding, buttering, and welds	SFA 5.4, 5.9, 5.11, and 5.14	308L, 309L, ENiCrFe-7, or ERNiCrFe-7
Pressure boundary welds	Low alloy steel	SFA 5.5, 5.23, 5.28
Passive Residual Heat Removal Heat Exchanger		
Pressure plates	SA-240	304L, 304LN
Pressure forgings	SA-336	F304L, F304LN
Cladding, buttering, and welds	SFA 5.4, 5.9, 5.11, and 5.14	308L, 309L, ENiCrFe-7, or ERNiCrFe-7
Pressure boundary welds	Low alloy steel	SFA 5.5, 5.23, 5.28
Tubing	SB-163	TP690

Table 5.2-2

REACTOR COOLANT WATER CHEMISTRY SPECIFICATIONS

Electrical conductivity	Determined by the concentration of boric acid and alkali present. Expected range is <1 to 40 μmhos/cm at 25°C.
Solution pH	Determined by the concentration of boric acid and alkali present. Expected values range between 4.2 (high boric acid concentration) and 10.5 (low boric acid concentration) at 25°C. Values will be 5.0 or greater at normal operating temperatures.
Oxygen(1)	0.1 ppm, maximum
Chloride(2)	0.15 ppm, maximum
Fluoride(2)	0.15 ppm, maximum
Hydrogen(3)	25 to 50 cm^3 (STP)/kg H_2O
Suspended solids(4)	0.2 ppm, maximum
pH control agent (Li7OH)(5)	Lithium is coordinated with boron per fuel warranty contract.
Boric acid	Variable from 0 to 4000 ppm as boron
Silica(6)	1.0 ppm, maximum
Aluminum(6)	0.05 ppm, maximum
Calcium(6) + magnesium	0.05 ppm, maximum
Magnesium(6)	0.025 ppm, maximum

Notes:

1. Oxygen concentration must be controlled to less than 0.1 ppm in the reactor coolant by scavenging with hydrazine prior to plant operation above 200°F. During power operation with the specified hydrogen concentration maintained in the coolant, the residual oxygen concentration will not exceed 0.005 ppm.
2. Halogen concentrations must be maintained below the specified values regardless of system temperature.
3. Hydrogen must be maintained in the reactor coolant for plant operations with nuclear power above 1 MW. The normal operating range should be 30-40 cm^3 (STP) H_2/kg H_2O.
4. Solids concentration determined by filtration through filter having 0.45-μm pore size.
5. The specified lithium concentrations must be established for startup testing prior to heatup beyond 150°F. During cold hydrostatic testing and hot functional testing in the absence of boric acid, the reactor coolant limits for lithium hydroxide must be maintained to inhibit halogen stress corrosion cracking.
6. These limits are included in the table of reactor coolant specifications as recommended standards for monitoring coolant purity. Establishing coolant purity within the limits shown for these species is judged desirable with the current data base to minimize fuel clad crud deposition, which affects the corrosion resistance and heat transfer of the clad.

Table 5.2-3

ASME CODE CASES

Code Case Number	Title
N-4-11	Special Type 403 Modified Forgings or Bars, Section III, Division 1, Class 1 and Class CS
N-20-4	SB-163 Nickel-Chromium-Iron Tubing (Alloys 600 and 690) and Nickel-Iron-Chromium Alloy 800 at a Specified Minimum Yield Strength of 40.0 ksi and Cold Worked Alloy 800 at Yield Strength of 47.0 ksi, Section III, Division 1, Class 1
N-60-5	Material for Core Support Structures, Section III, Division 1[(a)]
N-71-18	Additional Material for Subsection NF, Class 1, 2, 3 and MC Component Supports Fabricated by Welding, Section III Division 1
[*N-122-2*	*Stress Indices for integral Structural Attachments Section III, Division 1, Class 1*]*
N-249-14	Additional Materials for Subsection NF, Class 1, 2, 3, and MC Supports Fabricated Without Welding, Section III, Division 1[(b)]
[*N-284-1*	*Metal Containment Shell Buckling Design Methods, Section III, Division 1 Class MC*]*
[*N-318-5*	*Procedure for Evaluation of the Design of Rectangular Cross Section Attachments on Class 2 or 3 Piping Section III, Division*]*
[*N-319-3*	*Alternate Procedure for Evaluation of Stresses in Butt Welding Elbows in Class 1 Piping Section III, Division 1*]*
[*N-391-2*	*Procedure for Evaluation of the Design of Hollow Circular Cross Section Welded Attachments on Class 1 Piping Section III, Division 1*]*
[*N-392-3*	*Procedure for Valuation of the Design of Hollow Circular Cross Section Welded Attachments on Class 2 and 3 Piping Section III, Division 1*[(c)]]*
N-474-2	Design Stress Intensities and Yield Strength Values for UNS06690 With a Minimum Yield Strength of 35 ksi, Class 1 Components, Section III, Division 1
2142-1	F-Number Grouping for Ni-Cr-Fe, Classification UNS N06052 Filler Metal, Section IX
2143-1	F-Number Grouping for Ni-Cr-Fe, Classification UNS W86152 Welding Electrode, Section IX

Notes:
(a) Use of this code case will meet the conditions for Code Case N-60-4 in Reg. Guide 1.85 Revision 30.
(b) Use of this code case will meet the conditions for Code Case N-249-10 in Reg. Guide 1.85 Revision 30.
(c) Use of this code case will meet the conditions for Code Case N-392-1 in Reg. Guide 1.84 Revision 30.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

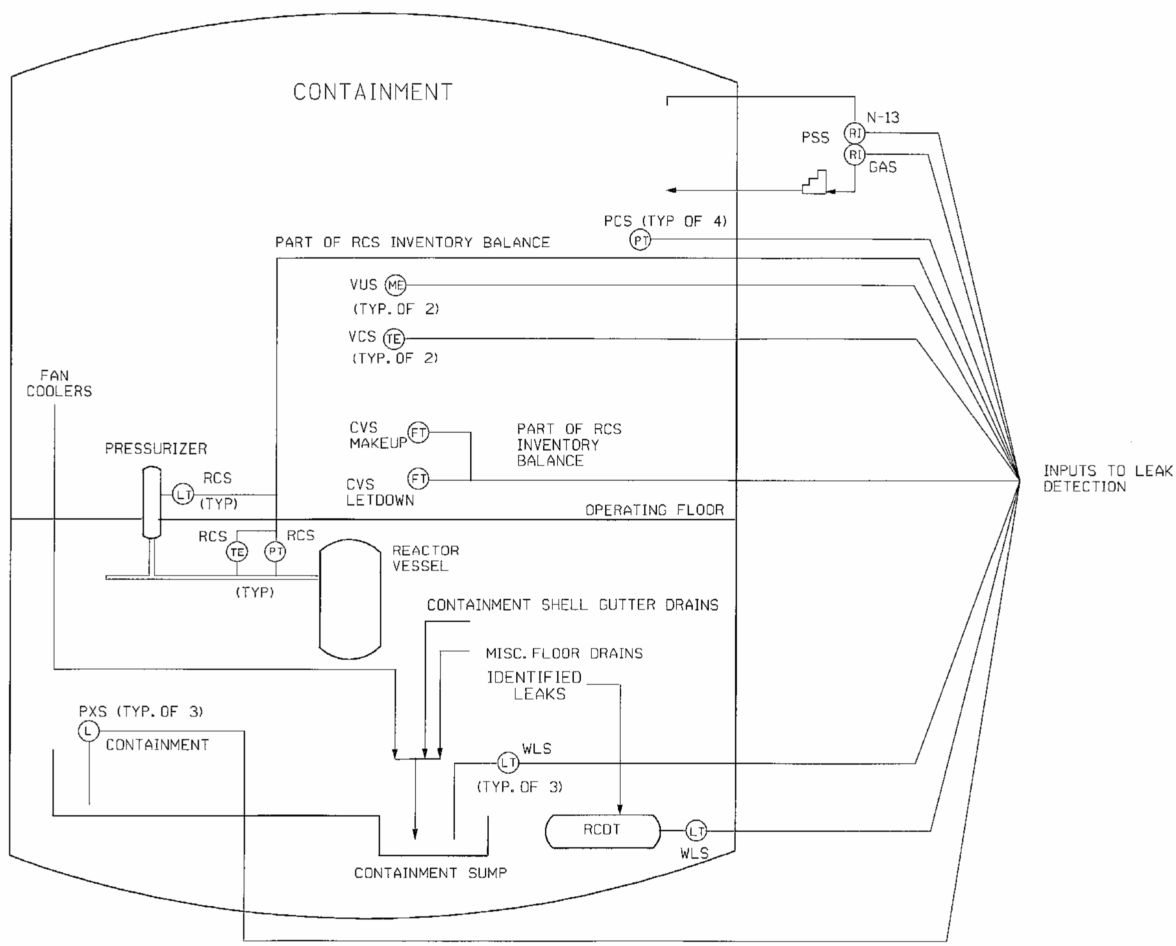


Figure 5.2-1

Leak Detection Approach

5.3 Reactor Vessel

5.3.1 Reactor Vessel Design

5.3.1.1 Safety Design Bases

The reactor vessel, as an integral part of the reactor coolant pressure boundary will be designed, fabricated, erected and tested to quality standards commensurate with the requirements set forth in 10 CFR 50, 50.55a and General Design Criterion 1. Design and fabrication of the reactor vessel is carried out in accordance with ASME Code, Section III, Class 1 requirements. Subsections 5.2.3 and 5.3.2 provide further details.

The performance and safety design bases of the reactor vessel follow:

- The reactor vessel provides a high integrity pressure boundary to contain the reactor coolant, heat generating reactor core, and fuel fission products. The reactor vessel is the primary pressure boundary for the reactor coolant and the secondary barrier against the release of radioactive fission products.
- The reactor vessel provides support for the reactor internals and core to ensure that the core remains in a coolable configuration.
- The reactor vessel directs main coolant flow through the core by close interface with the reactor internals.
- The reactor vessel provides for core internals location and alignment.
- The reactor vessel provides support and alignment for the control rod drive mechanisms and in-core instrumentation assemblies.
- The reactor vessel provides support and alignment for the integrated head assembly.
- The reactor vessel provides an effective seal between the refueling cavity and sump during refueling operations.
- The reactor vessel supports and locates the main coolant loop piping.
- The reactor vessel provides support for safety injection flow paths.
- The reactor vessel serves as a heat exchanger during core meltdown scenario with water on the outside surface of the vessel.

5.3.1.2 Safety Description

The reactor vessel consists of a cylindrical section with a transition ring, hemispherical bottom head, and a removable flanged hemispherical upper head (Figure 5.3-1). Key dimensions are shown in Figures 5.3-5 and 5.3-6. The cylindrical section consists of two shells, the upper shell and the lower shell. The upper and lower shells and the lower hemispherical head are fabricated

from low alloy steel and clad with austenitic stainless steel. The upper shell forging is welded to the lower shell forging, and the lower shell is welded to the transition ring, which is welded to the hemispherical bottom head. The removable flanged hemispherical upper head consists of a single forging, which includes the closure head flange and the closure head dome. The closure head is fabricated from a low alloy steel forging and clad with austenitic stainless steel. Specifics of the processes used in base materials, clad material, and weld materials are discussed in subsection 5.2.3. The removable flanged hemispherical closure head is attached to the vessel (consisting of the upper shell-lower shell-bottom hemispherical head) by studs. Two metal o-rings are used for sealing the two assemblies. Inner and outer monitor tubes are provided through the upper shell to collect any leakage past the o-rings. Details of the head gasket monitoring connections are included in subsection 5.2.5.2.1.

The reactor vessel supports the internals. An internal ledge is machined into the top of the upper shell section. The core barrel flange rests on the ledge. A large circumferential spring is positioned on the top surface of the core barrel flange. The upper support plate rests on the top surface of the spring. The spring is compressed by installation of the reactor vessel closure head and the upper and lower core support assemblies are restrained from any axial movements.

Four core support pads are located on the bottom hemispherical head just below the transition ring-to-lower shell circumferential weld. The core support pads function as a clevis. At assembly, as the lower internals are lowered into the vessel, the keys at the bottom of the lower internals engage the clevis in the axial direction. With this design, the internals are provided with a lateral support at the furthest extremity and may be viewed as a beam supported at the top and bottom.

The interfaces between the reactor vessel and the lower internals core barrel are such that the main coolant flow enters through the inlet nozzle and is directed down through the annulus between the reactor vessel and core barrel and flows up through the core. The annulus is designed such that the core remains in a coolable configuration for all design conditions.

Prior to installation of the internals into the reactor vessel, guide studs are assembled into the upper shell. Dimensional relationships are established between the guide studs and the core support pads such that when the lower internals lifting rig engages the guide studs, the keys at the bottom of the lower internals are in relative circumferential position to enter the core support pads.

There are 69 penetrations in the removable flanged hemispherical head (closure head) that are used to provide access for the control rod drive mechanisms. Each control rod drive mechanism is positioned in its opening and welded to the closure head penetration. In addition there are 42 penetrations in the closure head used to provide access for in-core and core exit instrumentation. A tube is inserted into each of the 42 penetrations and is welded into place.

Lugs are welded to the outside surface of the closure head along the outer periphery of the dome section. The purpose of these lugs is to provide support and alignment for the integrated head package.

Attached to the top surface and along the outer periphery of the upper shell is a ring section. During field assembly the ring is welded to the refueling cavity seal liner. This ring provides an effective water seal between the refueling cavity and sump during refueling operations.

A support pad is integral to each of the four inlet nozzles. The reactor vessel is supported by the pads. The pads rest on steel base pads atop a support structure, which is attached to the concrete foundation wall. Thermal expansion and contraction of the vessel are accommodated by sliding surfaces between the support pads and the base plates. Side stops on these plates keep the vessel centered and resist lateral loads.

The reactor vessel primary and direct vessel injection (DVI) nozzles are located in the upper shell. These nozzles are either forged as part of the upper shell forging or are fabricated by “set in” construction such that the welding is through the vessel shell forging. A stainless steel safe end is shop welded to each of the four inlet, two outlet and two DVI nozzles to facilitate field welding without heat treatment to the stainless steel reactor coolant piping system. The primary coolant nozzles support one end of the primary coolant system. Reaction loads are transferred into the nozzles and eventually into the support pads. The inlet and outlet elevation nozzles are offset in different planes by 17.5 inches. This allows pump maintenance without discharging the core.

There are no penetrations in the reactor vessel below the core. This eliminates the possibility of a loss-of-coolant accident by leakage from the reactor vessel that would allow the core to be uncovered.

5.3.1.3 System Safety Evaluation

The reactor vessel is part of the reactor coolant system. Load and stress evaluation for operating loads and mechanical transients of safe shutdown earthquake (SSE), and pipe ruptures appear in subsection 3.9.3.

5.3.1.4 Inservice Inspection/Inservice Testing

Inservice surveillance is discussed in subsection 5.3.4.7.

5.3.2 Reactor Vessel Materials

5.3.2.1 Material Specifications

Material specifications are in accordance with the ASME Code requirements and are given in subsection 5.2.3. All ferritic reactor vessel materials comply with the fracture toughness requirements of Section 50.55a and Appendices G and H of 10 CFR 50.

The ferritic materials of the reactor vessel beltline are restricted to the maximum limits shown in Table 5.3-1. Copper, nickel, and phosphorus content is restricted to reduce sensitivity to irradiation embrittlement in service.

5.3.2.2 Special Processes Used for Manufacturing and Fabrication

The reactor vessel is classified as AP1000 Class A. Design and fabrication of the reactor vessel is carried out in accordance with ASME Code, Section III, Class 1 requirements. The shell sections, flange, and nozzles are manufactured as forgings. The hemispherical heads are made from dished plates or forgings. The reactor vessel parts are joined by welding, using the single or multiple wire submerged arc and the shielded metal arc processes.

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

At locations in the reactor vessel where stainless steel and nickel-chromium-iron alloy are joined, the final joining beads are nickel-chromium-iron alloy weld metal in order to prevent cracking.

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

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

Freedom from underclad cracking is provided by special evaluation of the procedure qualification for cladding applied on low-alloy steel (SA-508, Class 3).

Minimum preheat requirements have been established for pressure boundary welds using low-alloy material. The preheat is maintained until either a low temperature (400°F – 500°F) post heat treatment, an intermediate postweld heat treatment or a full postweld heat treatment is performed.

A field weld is made, after the reactor vessel has been set, to install the permanent reactor vessel cavity seal ring. This stainless steel filler weld joins the seal ring to the reactor vessel seal ledge. A minimum preheat is specified for this weld in compliance with the ASME Code requirements.

5.3.2.3 Special Methods for Nondestructive Examination

The nondestructive examination (NDE) of the reactor vessel and its appurtenances is conducted in accordance with ASME Code, Section III requirements; also, numerous examinations are performed in addition to ASME Code, Section III requirements. The nondestructive examination of the vessel is discussed in the following paragraphs, and the reactor vessel quality assurance program is given in Table 5.3-2.

5.3.2.3.1 Ultrasonic Examination

In addition to the required ASME Code straight beam ultrasonic examination, 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.

In addition to the ASME Code, Section III nondestructive examination, 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 postweld heat treatment.

After hydrotesting, 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 performed in addition to the ASME Code, Section III nondestructive examination requirements.

5.3.2.3.2 Penetrant Examinations

The partial penetration welds for the control rod drive mechanism head adapters and the top instrumentation tubes are inspected by dye penetrant after the root pass, in addition to ASME code requirements. Core support block attachment welds are inspected by dye penetrant after the first layer of weld metal and after each 0.5 inch of weld metal. Clad surfaces and other vessel and head internal surfaces are inspected by dye penetrant after the hydrostatic test.

5.3.2.3.3 Magnetic Particle Examination

Magnetic particle examination requirements below are in addition to the magnetic particle examination requirements of Section III of the ASME Code. All magnetic particle examinations of materials and welds are performed in accordance with the following:

- Prior to the final postweld heat treatment, only by the prod, coil, or direct contact method
- After the final postweld 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 Section III of the ASME Code.

Surface Examinations

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

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

- Magnetic particle examination of 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 and prior to cladding.

Weld Examination

Magnetic particle examination of the welds attaching the closure head lifting lugs and refueling seal ledge to the reactor vessel after the first layer and each 0.5 inch of weld metal is deposited. All pressure boundary welds are examined after back-chipping or back-grinding operations.

5.3.2.4 Special Controls for Ferritic and Austenitic Stainless Steels

Welding of ferritic steels and austenitic stainless steels is discussed in subsection 5.2.3. Subsection 5.2.3 includes discussions on the degree of conformance with Regulatory Guide 1.44. Section 1.9 discusses the degree of conformance with Regulatory Guides, including 1.31 and 1.34 (if applicable), as well as 1.37, 1.43, 1.50, 1.71, and 1.99.

5.3.2.5 Fracture Toughness

Assurance of adequate fracture toughness of ferritic materials in the reactor vessel (ASME Code, Section III, Class 1 component) is provided by compliance with the requirements for fracture

toughness testing included in NB-2300 to Section III of the ASME Code and Appendix G of 10 CFR 50.

The initial Charpy V-notch minimum upper shelf fracture energy levels for the reactor vessel beltline base metal transverse direction and welds are 75 foot-pounds, as required by Appendix G of 10 CFR 50. The vessel fracture toughness data are given in Table 5.3-3. The AP1000 end-of-life RT_{NDT} and upper shelf energy projections were estimated using Regulatory Guide 1.99 for the end-of-life neutron fluence at the 1/4-thickness (T) and ID reactor vessel locations.

5.3.2.6 Material Surveillance

In the surveillance program, the evaluation of radiation damage is based on pre-irradiation testing of Charpy V-notch and tensile specimens and postirradiation testing of Charpy V-notch, tensile, and 1/2-T 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 conforms to ASTM E-185, (Reference 1) and 10 CFR 50, Appendix H.

The reactor vessel surveillance program incorporates eight specimen capsules. The capsules are located in guide baskets welded to the outside of the core barrel as shown in Figure 5.3-4 and positioned directly opposite the center portion of the core. The capsules can be removed when the vessel head is removed. The capsules contain reactor vessel weld metal, base metal, and heat-affected zone metal specimens. The base metal specimens are 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. The 8 capsules contain 72 tensile specimens, 480 Charpy V-notch specimens, and 48 compact tension specimens. Archive material sufficient for two additional capsules and heat-affected-zone (HAZ) materials is retained.

Dosimeters, as described below, 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 is made for surveillance material and as deposited weld metal. Each of the eight capsules contains the specimens shown.

The following dosimeters and thermal monitors are included in each of the eight capsules:

- Dosimeters
  - Iron
  - Copper
  - Nickel
  - Cobalt-aluminum (0.15-percent cobalt)
  - Cobalt-aluminum (cadmium shielded)
  - Uranium-238 (cadmium shielded)
  - Neptunium-237 (cadmium shielded)

- Thermal Monitors

  – 97.5-percent lead, 2.5-percent silver, (579°F melting point)
  – 97.5-percent lead, 1.75-percent silver, 0.75-percent tin (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 measurements of the irradiated samples in the capsules, assuming the same neutron spectrum at the samples and the vessel inner wall, are described in subsection 5.3.2.6.1. The anticipated degree to which the specimens perturb the fast neutron flux and energy distribution is considered in the evaluation of the surveillance specimen data. Verification and possible readjustment of the calculated wall exposure is made by the use of data on capsules withdrawn. The recommended program schedule for removal of the capsules for post-irradiation testing includes five capsules to be withdrawn instead of four as specified in ASTM E-185 (Reference 1) and Appendix H of 10 CFR 50. The following is the recommended withdrawal schedule of capsules for AP1000.

Capsule	Withdrawal Time
1st	When the accumulated neutron fluence of the capsule is 5 x 10^{18} n/cm^2.
2nd	When the accumulated neutron fluence of the capsule corresponds to the approximate end of life fluence at the reactor vessel 1/4T location.
3rd	When the accumulated neutron fluence of the capsule corresponds to the approximate end of life fluence at the reactor vessel inner wall location.
4th	When the accumulated neutron fluence of the capsule corresponds to a fluence not less than once or greater than twice the peak end of vessel life fluence.
5th	End of plant design objective of 60 years
6th	Standby
7th	Standby
8th	Standby

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

The use of passive neutron sensors such as those included in the internal surveillance capsule dosimetry sets does not yield a direct measure of the energy dependent neutron flux level at the measurement location. Rather, the activation or fission process is a measure of the integrated effect that the time and energy dependent neutron flux has on the target material over the course of

the irradiation period. An accurate estimate of the average neutron flux level, and hence, time integrated exposure (fluence) experienced by the sensors 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:

- The measured specific activity of each sensor
- The physical characteristics of each sensor
- The operating history of the reactor
- The energy response of each sensor
- The neutron energy spectrum at the sensor location

The procedures used to determine sensor specific activities, to develop reaction rates for individual sensors from the measured specific activities and the operating history of the reactor, and to derive key fast neutron exposure parameters from the measured reaction rates are described below.

5.3.2.6.1.1 Determination of Sensor Reaction Rates

The specific activity of each of the radiometric sensors is determined using established ASTM procedures. Following sample preparation and weighing, the specific activity of each sensor is determined by means of a high purity germanium gamma spectrometer. In the case of the surveillance capsule multiple foil sensor sets, these analyses are performed by direct counting of each of the individual wires; or, as in the case of U-238 and Np-237 fission monitors, by direct counting preceded by dissolution and chemical separation of cesium from the sensor.

The irradiation history of the reactor over its operating lifetime is determined from plant power generation records. In particular, operating data are extracted on a monthly basis from reactor startup to the end of the capsule irradiation period. For the sensor sets utilized in the surveillance capsule irradiations, the half-lives of the product isotopes are long enough that a monthly histogram describing reactor operation has proven to be an adequate representation for use in radioactive decay corrections for the reactions of interest in the exposure evaluations.

Having the measured specific activities, the operating history of the reactor, and the physical characteristics of the sensors, reaction rates referenced to full power operation are determined from the following equation:

$$R = \frac{A}{N_0 \, F \, Y \sum_j \frac{P_j}{P_{ref}} C_j \left[1 - e^{-\lambda t_j}\right] e^{-\lambda t_d}}$$

where:

A = measured specific activity provided in terms of disintegrations per second per gram of target material (dps/gm).

R = reaction rate averaged over the irradiation period and referenced to operation at a core power level of P_{ref} expressed in terms of reactions per second per nucleus of target isotope (rps/nucleus).

N_0 = number of target element atoms per gram of sensor.

F = weight fraction of the target isotope in the sensor material.

Y = number of product atoms produced per reaction.

P_j = average core power level during irradiation period j (MW).

P_{ref} = maximum or reference core power level of the reactor (MW).

C_j = calculated ratio of $\phi(E > 1.0 \text{ MeV})$ during irradiation period j to the time weighted average $\phi(E > 1.0 \text{ MeV})$ over the entire irradiation period.

λ = decay constant of the product isotope (sec-1).

t_j = length of irradiation period j (sec).

t_d = decay time following irradiation period j (sec).

and the summation is carried out over the total number of monthly intervals comprising the total irradiation period.

In the above equation, the ratio P_j/P_{ref} accounts for month-by-month variation of power level within a given fuel cycle. The ratio C_j is calculated for each fuel cycle and accounts for the change in sensor reaction rates caused by variations in flux level due to changes in core power spatial distributions from fuel cycle to fuel cycle. Since the neutron flux at the measurement locations within the surveillance capsules is dominated by neutrons produced in the peripheral fuel assemblies, the change in the relative power in these assemblies from fuel cycle to fuel cycle can have a significant impact on the activation of neutron sensors. For a single-cycle irradiation, $C_j = 1.0$. However, for multiple-cycle irradiations, particularly those employing low leakage fuel management, the additional C_j correction must be utilized in order to provide accurate determinations of the decay corrected reaction rates for the dosimeter sets contained in the surveillance capsules.

5.3.2.6.1.2 Corrections to Reaction Rate Data

Prior to using the measured reaction rates in the least squares adjustment procedure discussed in Section 5.3.2.6.1.3, additional corrections are made to the U-238 measurements to account for the presence of U-235 impurities in the sensors as well as to adjust for the build-in of plutonium isotopes over the course of the irradiation.

In addition to the corrections made for the presence of U-235 in the U-238 fission sensors, corrections are also made to both the U-238 and Np-237 sensor reaction rates to account for gamma ray induced fission reactions occurring over the course of the irradiation.

5.3.2.6.1.3 Least Squares Adjustment Procedure

Least squares adjustment methods provide the capability of combining the measurement data with the neutron transport calculation resulting in a Best Estimate neutron energy spectrum with associated uncertainties. Best Estimates for key exposure parameters such as neutron fluence (E > 1.0 MeV) or iron atom displacements (dpa) along with their uncertainties are then easily obtained from the adjusted spectrum. The use of measurements in combination with the analytical results reduces the uncertainty in the calculated spectrum and acts to remove biases that may be present in the analytical technique.

In general, the least squares methods, as applied to pressure vessel fluence evaluations, act to reconcile the measured sensor reaction rate data, dosimetry reaction cross-sections, and the calculated neutron energy spectrum within their respective uncertainties. For example,

$$R_i \pm \delta_{R_i} = \sum_g (\sigma_{ig} \pm \delta_{\sigma_{ig}})(\phi_g \pm \delta_{\phi_g})$$

relates a set of measured reaction rates, Ri, to a single neutron spectrum, ϕg, through the multigroup dosimeter reaction cross-section, σig, each with an uncertainty δ.

The use of least squares adjustment methods in LWR dosimetry evaluations is not new. The American Society for Testing and Materials (ASTM) has addressed the use of adjustment codes in ASTM Standard E944, "Application of Neutron Spectrum Adjustment Methods in Reactor Surveillance" and many industry workshops have been held to discuss the various applications. For example, the ASTM-EURATOM Symposia on Reactor Dosimetry holds workshops on neutron spectrum unfolding and adjustment techniques at each of its bi-annual conferences.

The primary objective of the least squares evaluation is to produce unbiased estimates of the neutron exposure parameters at the location of the measurement. The analytical method alone may be deficient because it inherently contains uncertainty due to the input assumptions to the calculation. Typically these assumptions include parameters such as the temperature of the water in the peripheral fuel assemblies, by-pass region, and downcomer regions, component dimensions, and peripheral core source. Industry consensus indicates that the use of calculation alone results in overall uncertainties in the neutron exposure parameters in the range of 15-20% (1σ).

The application of the least squares methodology requires the following input:

1. The calculated neutron energy spectrum and associated uncertainties at the measurement location.

2. The measured reaction rate and associated uncertainty for each sensor contained in the multiple foil set.

3. The energy dependent dosimetry reaction cross-sections and associated uncertainties for each sensor contained in the multiple foil sensor set.

For a given application, the calculated neutron spectrum is obtained from the results of plant specific neutron transport calculations applicable to the irradiation period experienced by the dosimetry sensor set. This calculation is performed using the benchmarked transport calculational methodology described in Section 5.3.2.6.2. The sensor reaction rates are derived from the measured specific activities obtained from the counting laboratory using the specific irradiation history of the sensor set to perform the radioactive decay corrections. The dosimetry reaction cross-sections and uncertainties that are utilized in LWR evaluations comply with ASTM Standard E1018, "Application of ASTM Evaluated Cross-Section Data File, Matrix E 706 (IIB)."

The uncertainties associated with the measured reaction rates, dosimetry cross-sections, and calculated neutron spectrum are input to the least squares procedure in the form of variances and covariances. The assignment of the input uncertainties also follows the guidance provided in ASTM Standard E 944.

5.3.2.6.2 Calculation of Integrated Fast Neutron (E > 1.0 MeV) Flux at the Irradiation Samples

A generalized set of guidelines for performing fast neutron exposure calculations within the reactor configuration, and procedures for analyzing measured irradiation sample data that can be correlated to these calculations, has been promulgated by the Nuclear Regulatory Commission (NRC) in Regulatory Guide 1.190, or RG-1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence" [Reference 2]. Since different calculational models exist and are continuously evolving along with the associated model inputs, e.g., cross-section data, it is worthwhile summarizing the key models, inputs, and procedures that the NRC staff finds acceptable for use in determining fast neutron exposures within the reactor geometry. This material is highlighted in the subsection of material that is provided below.

5.3.2.6.2.1 Calculation and Dosimetry Measurement Procedures

The selection of a particular geometric model, the corresponding input data, and the overall methodology used to determine fast neutron exposures within the reactor geometry are based on the needs for accurately determining a solution to the problem that must be solved and the data/resources that are currently available to accomplish this task. Based on these constraints, engineering judgment is applied to each problem based on an analyst's thorough understanding of the problem, detailed knowledge of the plant, and due consideration to the strengths and weaknesses associated with a given calculational model and/or methodology. Based on these conditions, RG-1.190 does not recommend using a singular calculational technique to determine fast neutron exposures. Instead, RG-1.190 suggests that one of the following neutron transport tools be used to perform this work.

- Discrete Ordinates Transport Calculations
  - Adjoint calculations benchmarked to a reference-forward calculation, or stand-alone forward calculations.
  - Various geometrical models utilized with suitable mesh spacing in order to accurately represent the spatial distribution of the material compositions and source.

– In performing discrete ordinates transport calculations, RG-1.190 also suggests that a P_3 angular decomposition of the scattering cross-sections be used, as a minimum.

– RG-1.190 also recommends that discrete ordinates transport calculations utilize S_8 angular quadrature, as a minimum.

– RG-1.190 indicates that the latest version of the Evaluated Nuclear Data File, or ENDF/B, should be used for determining the nuclear cross-sections; however, cross-sections based on earlier or equivalent nuclear data sets that have been thoroughly benchmarked are also acceptable.

- Monte Carlo Transport Calculations

  A complete description of the Westinghouse pressure vessel neutron fluence methodology, which is based on discrete ordinates transport calculations, is provided in Reference 3. The Westinghouse methodology adheres to the guidelines set forth in Regulatory Guide 1.190.

5.3.2.6.2.2 Plant-Specific Calculations

The location, selection, and evaluation of neutron dosimetry and the associated radiometric monitors, as well as fast ($E > 1.0$ MeV) neutron fluence assessments of the AP1000 reactor pressure vessel, are conducted in accordance with the guidelines that are specified in Regulatory Guide 1.190.

5.3.2.7 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. The closure stud material meets the fracture toughness requirements of the ASME Code, Section III, and 10 CFR 50, Appendix G. Conformance with Regulatory Guide 1.65, Materials and Inspections for Reactor Vessel Closure Studs, is discussed in Section 1.9. Nondestructive examinations are performed in accordance with the ASME Code, Section III. See subsection 5.2.3 for restrictions on lubricants.

Refueling procedures require that the reactor vessel closure studs, nuts, and washers are lifted out of their respective holes and a stud support collar be put in place prior to the lift of the integrated head assembly during preparation for refueling. In this way the studs are lifted with and stored on the head. An alternative method is to remove the reactor vessel closure studs, nuts, and washers from the reactor closure and place them in storage racks during preparation for refueling. In this method, the storage racks are 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. In either case, the reactor closure studs are not exposed to the borated refueling cavity water. Additional protection against the possibility of incurring corrosion effects is provided by the use of a 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.

5.3.3 Pressure-Temperature Limits

5.3.3.1 Limit Curves

Heatup and cooldown pressure-temperature limit curves are required as a means of protecting the reactor vessel during startup and shut down to minimize the possibility of fast fracture. The methods outlined in Appendix G of Section III of the ASME Code are employed in the analysis of protection against nonductile failure. 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}), initial RT_{NDT} and margin. The extent of the RT_{NDT} shift is enhanced by certain chemical elements (such as copper and nickel).

Predicted ΔRT_{NDT} values are derived considering the effect of fluence and copper and nickel content for the reactor vessel steels exposed to 550°F temperature. U.S. NRC Regulatory Guide 1.99 is used in calculating adjusted reference temperature. Since the AP1000 cold leg temperature exceeds 525°F (minimum steady-state temperature is 535°F at 100% power, thermal design flow, and 10% tube plugging), the procedures of Regulatory Guide 1.99 for nominal embrittlement apply. The heatup and cooldown curves are developed considering a sufficient magnitude of radiation embrittlement so that no unirradiated ferritic materials in other components of the reactor coolant system will be limiting in the analysis.

The pressure-temperature curves are developed considering a radiation embrittlement of up to 54 effective full power years (EFPY) consistent with the plant design objective of 60 years with 90 percent availability. Copper, nickel contents and initial RT_{NDT} for materials in the reactor vessel beltline region and the reactor vessel flange and the closure head flange region are shown in Tables 5.3-1 and 5.3-3. The operating curves are developed with the methodology given in Reference 6, which is in accordance with 10 CFR 50, Appendix G with the following exceptions:

1. The fluence values used are calculated fluence values (i.e., comply with Regulatory Guide 1.190), not the best-estimate fluence values.

2. The K_{Ic} critical stress intensities are used in place of the K_{Ia} critical stress intensities. This methodology is taken from approved ASME Code Case N-641 (which covers Code Cases N-640 and N-588).

3. The 1996 Version of Appendix G to Section XI is used rather than the 1989 version.

The curves are applicable up to 54 effective full-power years. These curves, shown in Figures 5.3-2 and 5.3-3, are generic curves for the AP1000 reactor vessel design and they are limiting curves based on copper and nickel material composition. These curves are applicable as long as the following criteria are met:

- 10 CFR 50, Appendix G as related to pressure-temperature remains unchanged,

- Adjusted Reference Temperatures at 1/4T and 3/4T locations remain below the bases of Figures 5.3-2 and 5.3-3

The results of the material surveillance program described in subsection 5.3.2.6 will be used to verify the validity of ΔRT_{NDT} used in the calculation for the development of heatup and cooldown curves. The projected fluence, copper, and nickel contents along with the RT_{NDT} calculation will be adjusted if necessary, from time to time using the surveillance capsule results. This may require the development of new heatup and cooldown curves.

Higher rates of temperature changes when the reactor coolant system pressure is at or above the operating pressure do not impact the determination of the proper curve to use. Figure 5.3-2 also includes a curve for the leak test limit at steady-state temperature and curves for the criticality limit for nuclear heatup.

Temperature limits for core operation, inservice leak and hydrotests are calculated in accordance with the ASME Code, Section III, Appendix G.

5.3.4 Reactor Vessel Integrity

5.3.4.1 Design

The reactor vessel is the high pressure containment boundary used to support and enclose the reactor core. It provides flow direction with the reactor internals through the core and maintains a volume of coolant around the core. The vessel is cylindrical, with a transition ring, hemispherical bottom head, and removable flanged hemispherical upper head. The vessel is fabricated by welding together the lower head, the transition ring, the lower shell, and the upper shell. The upper shell contains the penetrations from the inlet and outlet nozzles and direct vessel injection nozzles. The closure head is fabricated with a head dome and bolting flange. The upper head has penetrations for the control rod drive mechanisms, the incore instrumentation, head vent, and support lugs for the integrated head package.

The reactor vessel (including closure head) is approximately 40 feet long and has an inner diameter at the core region of 159 inches. The total weight of the vessel (including closure head and CRDMs) is approximately 417 tons. Surfaces which can become wetted during operation and refueling are clad to a nominal 0.22 inches of thickness with stainless steel welded overlay which includes the upper shell top surface but not the stud holes. The AP1000 reactor vessel's design objective is to withstand the design environment of 2500 psi and 650°F for 60 years. The major factor affecting vessel life is radiation degradation of the lower shell.

As a safety precaution, there are no penetrations below the top of the core. This eliminates the possibility of a loss of coolant accident by leakage from the reactor vessel which could allow the core to be uncovered. The core is positioned as low as possible in the vessel to limit reflood time in an accident. The main radial support system of the lower end of the reactor internals is accomplished by key and keyway joints to the vessel wall. At equally spaced points around the circumference, a clevis block is located on the reactor vessel inner diameter. A permanent cavity liner seal ring is attached to the top of the vessel shell for welding to the refueling cavity liner. To decrease outage time during refueling, access to the stud holes is provided to allow stud hole plugging with the head in place. By the use of a ring forging with an integral flange, the number of welds is minimized to decrease inservice inspection time.

The lower head has an approximate 6.5 feet inner spherical radius. The lower radial supports are located on the head at the elevation of the lower internals lower core support plate. The transition ring is welded to the lower shell course with the weld located outside the high fluence active core region. The lower shell is a ring forging about 8 inches thick with an inner diameter of 159 inches. The length of the shell is greater than 168 inches to place the upper shell weld outside of the active fuel region. The upper shell is a large ring forging. Included in this forging are four 22-inch inner diameter inlet nozzles, two 31-inch inner diameter outlet nozzles and two 6.81-inch inner diameter direct vessel injection nozzles (8-inch schedule 160 pipe connections). These nozzles are forged into the ring or are fabricated by “set in” construction. The inlet and outlet nozzles are offset axially in different planes by 17.5 inches. The injection nozzles are 100 inches down from the main flange and the outlet nozzles are 80 inches down and the inlet nozzles are 62.5 inches below the mating surface.

The closure head has a 77.5-inch inner spherical radius and a 188.0-inch O.D. outer flange. Cladding is extended across the bottom of the flange for refueling purposes. Forty-five, seven-inch diameter studs attach the head to the lower vessel and two metal o-rings are used for sealing. The upper head has sixty-nine 4-inch outer diameter penetrations for the control rod drive mechanism housings and forty-two penetrations for the incore instrumentation tubes.

The vessel is manufactured from low alloy steel plates and forgings to minimize size. The chemical content of the core region base material is specifically controlled. A surveillance program is used to monitor the radiation damage to the vessel material.

The four vessel supports are located beneath the inlet nozzles and the internals support ledge is machined into the top of the upper shell. The top of the upper shell contains the stud holes and has the sealing surface for the closure head. Inner and outer monitor tubes are provided through the shell to collect any leakage past the closure region o-rings.

The reactor vessel is designed and fabricated in accordance with the quality standards set forth in 10 CFR 50, General Design Criteria 1, 14, 30, and 31, and 50.55a; and the requirements of the American Society of Mechanical Engineers (ASME) Code, Section III. Principal design parameters of the reactor vessel are given in Table 5.3-5. The vessel design and construction enables inspection in accordance with the ASME Code, Section XI.

Cyclic loads are introduced by normal power changes, reactor trips, and startup and shutdown operations. These design base cycles are selected for fatigue evaluation and constitute a conservative design envelope for the design life. Thermal stratification during passive core cooling system operation and natural circulation cooldown is considered by performing a thermal/flow analysis using computational fluid dynamics techniques. This analysis includes thermally-induced fluid buoyancy, heat transfer between the coolant and the metal of the vessel and internals and uses thermal/flow boundary conditions based on an existing thermal/hydraulic transient analysis of the primary reactor coolant system. This analysis provides temperature maps that are used to evaluate thermal stresses.

Analysis proves 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. The heatup and cooldown rates imposed by plant operating limits are 100°F per hour for normal operations.

5.3.4.2 Materials of Construction

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

5.3.4.3 Fabrication Methods

The fabrication methods used in the construction of the reactor vessel are discussed in subsection 5.3.2.2.

5.3.4.4 Inspection Requirements

The nondestructive examinations performed on the reactor vessel are described in subsection 5.3.2.3.

5.3.4.5 Shipment and Installation

The reactor vessel is shipped in a horizontal position on a shipping skid 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, except for the vessel support surfaces, are painted with a heat-resistant paint before shipment.

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 housings. All head openings are sealed to prevent the entrance of moisture, and an adequate quantity of desiccant bags is 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.

5.3.4.6 Operating Conditions

Operating limitations for the reactor vessel are presented in subsection 5.3.3 and in the technical specifications.

In addition to the analysis of primary components discussed in subsection 3.9.1.4, the reactor vessel is further qualified to ensure against unstable crack growth under faulted conditions. Safeguard actuation following a loss-of-coolant, tube rupture or other similar emergency or faulted event produces relatively high thermal stresses in regions of the reactor vessel which come into contact with water from the passive core cooling system. Primary consideration is given to these areas, including the reactor vessel beltline region and the reactor vessel primary coolant nozzles, to ensure the integrity of the reactor vessel under these severe postulated transients. TMI Action Item II.K.2.13, is satisfied upon submittal of RT_{NDT} values which are below the pressurized thermal shock (PTS) rule screening values. The results given in Table 5.3-3 show that the issue is resolved.

For the beltline region, the NRC staff concluded that conservatively calculated screening criterion values of RT_{NDT} less than 270°F for plate material and axial welds, and less than 300°F for circumferential welds, present an acceptably low risk of vessel failure from pressurized thermal shock events. These values were chosen as the screening criterion in the pressurized thermal shock rule for 10 CFR 50.34 (new plants) and 10 CFR 50.61 (operating plants). The conservative methods chosen by the NRC staff for the calculation of RT_{PTS} for the purpose of comparison with the screening criterion is presented in paragraph (b)(2) of 10 CFR 50.61. Details of the analysis method and the basis for the pressurized thermal shock rule can be found in SECY-82-465 (Reference 4).

The revised pressurized thermal shock rule, (10 CFR 50.61), effective June 14, 1991 makes the procedure for calculating RT_{PTS} values consistent with the methods given in Regulatory Guide 1.99.

The reactor vessel beltline materials are specified in subsection 5.3.2. Evaluation of the AP1000 reactor vessel material showed that even at the fluence level which results in the highest RT_{PTS} value, this value is well below the screening criteria of 270°F. RT_{PTS} is RT_{NDT}, the reference nil ductility transition temperature as calculated by the method chosen by the NRC staff as presented in paragraph (b)(2) of 10 CFR 50.61, and the pressurized thermal shock rule. The pressurized thermal shock rule states that this method of calculating RT_{PTS} should be used in reporting values used to compare pressurized thermal shock to the above screening criterion set in the pressurized thermal shock rule. The screening criteria will not be exceeded using the method of calculation prescribed by the pressurized thermal shock rule for the vessel design objective. The material properties, and initial RT_{NDT} and end-of-life RT_{PTS} requirements and predictions are in Tables 5.3-1 and 5.3-3. The materials that are exposed to high fluence levels at the beltline region of the reactor vessel are subject to the pressurized thermal shock rule. These materials are a subset of the reactor vessel materials identified in subsection 5.3.2.

The principles and procedures of linear elastic fracture mechanics (LEFM) are used to evaluate thermal effects in the regions of interest. The linear elastic fracture mechanics 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 linear elastic fracture mechanics 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.

5.3.4.7 Inservice Surveillance

The internal surfaces of the reactor vessel are accessible for periodic inspection. Visual and/or nondestructive techniques are used. During refueling, the vessel cladding is capable of being inspected in certain areas of the upper shell above the primary coolant inlet nozzles, and if deemed necessary, the core barrel is capable of being removed, making the entire inside vessel surface accessible.

The closure head is examined visually during each refueling. Optical devices permit a selective inspection of the cladding, control rod drive mechanism nozzles, and the gasket seating surface.

Access to the top head surface is provided by 7 ports around the circumference of the integrated head package shroud and by 12 removable insulation panels, which interface with the head under the integrated head package shroud. Both the ports and the insulation panels provide access to the bare vessel head, and CRDM and instrumentation penetrations for use of a remote, mobile visual inspection manipulator to perform a 360° inspection around each penetration. The head insulation is a stand-off design with a minimum offset from the head surface of 3 inches.

The knuckle transition piece, which is the area of highest stress of the closure head, is accessible on the outer surface for visual inspection, dye penetrant or magnetic particle testing, and ultrasonic testing. The closure studs and nuts can be inspected periodically using visual, magnetic particle, and ultrasonic techniques.

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:

- Vessel shell, from the inside surface.
- Primary coolant nozzles, from the inside surface. Only partial outside diameter coverage is provided.
- Closure head, from the inside surface; bottom head, from the inside surface.
- Field welds between the reactor vessel nozzle safe ends and the main coolant piping, from the inside surface.

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

- Reactor internals are completely removable. The tools and storage space required to permit removal of the reactor internals are provided.
- The closure head is stored on a stand on the reactor operating deck during refueling to facilitate direct visual inspection.
- Reactor vessel studs, nuts, and washers can be removed to dry storage during refueling.
- Access is provided to the reactor vessel nozzle safe ends. The insulation covering the nozzle-to-pipe welds may be removed.

Because radiation levels and remote underwater accessibility limits access to the reactor vessel, several steps have been incorporated into the design and manufacturing procedures in preparation for the periodic nondestructive tests which are required by the ASME Code inservice inspection requirements. These are as follows:

- Shop ultrasonic examinations are performed on internally clad surfaces to an acceptance and repair standard to provide an adequate cladding bond to allow later ultrasonic testing of the

base metal from the inside surface. The size of cladding bond defect allowed is 0.25 inch by 0.75 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 (0.75-inch diameter) in other regions are rejected.

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

- The weld-deposited clad surface on both sides of the welds to be inspected is specifically prepared to ensure meaningful ultrasonic examinations.

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

- After the shop hydrostatic testing, full-penetration ferritic pressure boundary welds (with the exception of the closure head welds), as well as the nozzles to safe end welds, are ultrasonically examined from both the inside and outside diameters in addition to ASME Code, Section III requirements.

- Preservice examinations for the closure head will include a baseline top-of-the head visual examination; ultrasonic examinations of the inside diameter surface of each vessel head penetration; eddy current examinations of the surface of head penetration welds, the outside diameter surface of the vessel penetrations, and the inside diameter surface of the penetrations; and post-hydro liquid penetrant examinations of accessible surfaces that have undergone preservice inspection eddy current examinations.

The vessel design and construction enables inspection in accordance with the ASME Code, Section XI. The reactor vessel inservice inspection program is detailed in the technical specifications.

5.3.5 Reactor Vessel Insulation

5.3.5.1 Reactor Vessel Insulation Design Bases

Reactor vessel insulation is provided to minimize heat losses from the primary system. Nonsafety-related reflective insulation similar to that in use in current pressurized water reactors is utilized. The AP1000 reactor vessel insulation contains design features to promote in-vessel retention following severe accidents. In the unlikely event of a beyond design basis accident, the reactor cavity is flooded with water, and the reactor vessel insulation allows heat removal from core debris via boiling on the outside surface of the reactor vessel. The reactor vessel insulation permits a water layer next to the reactor vessel to promote heat transfer from the reactor vessel. This is accomplished by providing:

- A means of allowing water free access to the region between the reactor vessel and insulation.

- A means to allow steam generated by water contact with the reactor vessel to escape from the region surrounding the reactor vessel.

- The insulation support frame and the insulation panels form a structurally reliable flowpath for the water and steam.

The reactor vessel insulation and its supports are designed to withstand bounding pressure differentials across the reactor vessel insulation panels during the period that the reactor vessel is externally flooded with water and the core heat is removed from the vessel wall by water and generated steam is vented. This is accomplished by providing steam vents with a minimum flow area of 12 ft^2 from the vessel insulation annular space. The flow path from the reactor loop compartment to the reactor cavity provides an open flow path for water to flood the reactor cavity. The reactor vessel insulation water inlets are designed to minimize the pressure drop during ex-vessel cooling to permit water inflow to cool the vessel.

5.3.5.2 Description of Insulation

A schematic of the reactor vessel, the vessel insulation and the reactor cavity is shown in Figure 5.3-7. The insulation is mounted on a structural frame that is supported from the wall of the reactor cavity. The insulation panels are designed to have a minimum gap between the insulation and reactor vessel not less than 2 inches when subjected to the dynamic loads in the direction towards the vessel that result during ex-vessel cooling.

The bottom portion of the vessel insulation is constructed to provide a flow channel conducive for heat removal.

The structural frame supporting the insulation is designed to withstand the bounding severe accident loads while maintaining the flow path. The fasteners holding the insulation panels to the frame are also designed for these loads.

At the bottom of the insulation are water inlet assemblies. Each water inlet assembly is normally closed to prevent an air circulation path through the vessel insulation. The inlet assemblies are self-actuating passive devices. The inlet assemblies open when the cavity is filled with water. This permits ingress of water during a severe accident, while preventing excessive heat loss during normal operation.

The total flow area of the water inlet assemblies have sufficient margin to preclude significant pressure drop during ex-vessel cooling during a severe accident. The minimum total flow area for the water inlets assemblies is 6 ft^2. Due to the relatively low approach velocities in the flow paths leading to the reactor cavity, and due to the relatively large minimum flow area through each water inlet assembly, with an area of at least 7 in^2, the water inlet assemblies are not susceptible to clogging from debris inside containment. This 7 in^2 minimum area precludes clogging of the much larger steam flow path.

Near the top of the lower insulation segment are four steam vent ducts that provide a flow path for the steam/water within the reactor vessel/insulation annular space to flow back to the containment flood-up region. Each of the four ducts is 3 ft^2 in area, and they extend from the vessel/insulation annular space at 90 degrees circumferential spacing into the concrete forming the vessel cavity.

The vents then turn upward and are routed to discharge the steam/water back to the containment flood-up region. Each of the vents is covered with a cap that will be dislodged by the steam/water flow generated under the insulation with the cavity filled with water, but which remains in place when only normal air cooling flow is operating.

Extensive maintenance of the vessel insulation is not normally required. Periodic verification of the vessel insulation moving parts can be performed during refueling outages.

5.3.5.3 Description of External Vessel Cooling Flooded Compartments

Ex-vessel cooling during a severe accident is provided by flooding the reactor coolant system loop compartment including the vertical access tunnel, the reactor coolant drain tank room, and the reactor cavity. Water from these compartments replenishes the water that comes in contact with the reactor vessel and is boiled and vented to containment. The opening between the vertical access tunnel and the reactor coolant drain tank room is approximately 100 ft^2. Removable steel grating is provided over the inlet to the vertical access tunnel to restrict access to the lower compartments. This grating precludes large debris from being transported into the reactor cavity during ex-vessel cooling scenarios. Figure 5.3-8 depicts the flooded compartments that provide the water for ex-vessel cooling. The doorway between the reactor cavity compartment and the reactor coolant drain tank room consists of a normally closed door and a damper above the door. The door and damper arrangement, shown in Figure 5.3-9, maintains the proper air flow through the reactor cavity during normal operation. The damper prevents air from flowing into the reactor coolant drain tank compartment, but opens to permit flooding of the reactor cavity from the reactor coolant drain tank compartment. The damper opening has a minimum flow area of 8 ft^2 and is not susceptible to clogging from debris that can pass through the grating over the inlet to the vertical access tunnel. It is constructed of light-weight material to minimize the force necessary to open the damper and permit flooding and continued water flow through the opening during ex-vessel cooling. The damper provides an acceptable pressure drop through the opening during ex-vessel cooling.

DCD subsection 6.3.2.1.3 discusses post-accident operation of the passive core cooling system, which operates to flood the reactor cavity following an accident. DCD subsection 9.1.3 discusses the connections from the refueling cavity to the steam generator compartment that facilitate flooding of the reactor cavity following an accident.

5.3.5.4 Determination of Forces on Insulation and Support System

The forces that may be expected in the reactor cavity region of the AP1000 plant during a core damage accident in which the core has relocated to the lower head and the reactor cavity is reflooded can be based on test results from the ULPU test program (Reference 5). The particular configuration (Configuration V) reviewed closely models the full-scale AP1000 geometry of water in the region near the reactor vessel, between the reactor vessel and the reactor vessel insulation. The ULPU tests provide data on the pressure generated in the region between the reactor vessel and reactor vessel insulation. These data, along with observations and conclusions from heat transfer studies, are used to develop the functional requirements with respect to in-vessel retention for the reactor vessel insulation and support system. Interpretation of data collected from ULPU Configuration V experiments in conjunction with the static head of water that would be present in

the AP1000 is used to estimate forces acting on the rigid sections of insulation. The ULPU V test results indicate that the pressure variations in the flow channel between the vessel and the insulation are on the order of plus/minus 0.5 meters of water. Fast Fourier Transform analysis of the ULPU V pressure data is also included in the ULPU V test report. This analysis shows that the dominant frequency of the pressure variations is less than about 2 Hz. The natural frequency of the insulation structure is expected to be well above 2 Hz.

5.3.5.5 Design Evaluation

A structural analysis of the AP1000 reactor cavity insulation system will be performed to demonstrate that it meets the functional requirements discussed above. The analysis will encompass the insulation and support system and will include a determination of the stresses in support members, bolts, insulation panels and welds, as well as deflection of support members and insulation panels.

Loads on the insulation and the support structure include hydrostatic loads and dynamic loads from boiling. These loads are expected to be the same order as those analyzed for AP600, and the results of the AP1000 analysis are expected to show that the insulation is able to meet its functional requirements. The reactor vessel insulation provides an engineered pathway for water-cooling the vessel and for venting steam from the reactor cavity. These results will also be compared to the available test data.

The reactor vessel insulation is purchased equipment. The purchase specification for the reactor vessel insulation will require confirmatory static load analyses.

5.3.6 Combined License Information

5.3.6.1 Pressure-Temperature Limit Curves

The pressure-temp. curves shown in Figures 5.3-2 and 5.3-3 are generic curves for AP1000 reactor vessel design, and they are the limiting curves based on copper and nickel material composition. However, for a specific AP1000, these curves will be plotted based on material composition of copper and nickel. Use of plant-specific curves will be addressed by the Combined License applicant during procurement of the reactor vessel. As noted in the bases to Technical Specification 3.4.14, use of plant-specific curves requires evaluation of the LTOP system. This includes evaluating the setpoint pressure for the RNS relief valve.

5.3.6.2 Reactor Vessel Materials Surveillance Program

The Combined License applicant will address a reactor vessel reactor material surveillance program based on subsection 5.3.2.6.

5.3.6.3 Surveillance Capsule Lead Factor and Azimuthal Location Confirmation

The Combined License Applicant will address confirmation of the surveillance capsule lead factors and azimuthal locations through an analysis which includes modeling of the capsule/holder.

5.3.6.4 Reactor Vessel Materials Properties Verification

The Combined License applicant will address verification of plant-specific belt line material properties consistent with the requirements in subsection 5.3.3.1 and Tables 5.3-1 and 5.3-3. The verification will include a pressurized thermal shock evaluation based on as-procured reactor vessel material data and the projected neutron fluences for the plant design objective of 60 years. This evaluation report will be submitted for NRC staff review.

The verification will include structural analysis of the AP1000 reactor vessel insulation and support structure.

5.3.6.5 Reactor Vessel Insulation

The Combined License applicant will address verification that the reactor vessel insulation is consistent with the design bases established for in-vessel retention. The ULPU Configuration V test data is suitable to be used to develop the design loads for the AP1000 reactor vessel insulation design.

5.3.7 References

1. ASTM E-185-82, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels."

2. Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," United States Nuclear Regulatory Commission, Office of Nuclear Reactor Research, March, 2001.

3. WCAP-15557, "Qualification of the Westinghouse Pressure Vessel Neutron Fluence Evaluation Methodology," S. L. Anderson, August 2000.

4. NRC Policy Issue, "Pressurized Thermal Shock," SECY-82-465, November 23, 1982.

5. Theofanous, T.G., et al., "Limits of Coolability in the AP1000-Related ULPU-2400 Configuration V Facility," CRSS-03/06, June 2003.

6. WCAP-14040-NP-A, Revision 2, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves," J. D. Andrachek, et al., January 1996.

Table 5.3-1

MAXIMUM LIMITS FOR ELEMENTS OF THE REACTOR VESSEL

Element	Beltline Forging (percent)	As Deposited Weld Metal (percent)
Copper	0.03	0.03
Phosphorus	0.01	0.01
Vanadium	0.05	0.05
Sulfur	0.01	0.01
Nickel	0.85	0.85

Table 5.3-2

REACTOR VESSEL QUALITY ASSURANCE PROGRAM

	RT[(a)]	UT[(a)]	PT[(a)]	MT[(a)]
Forgings				
Flanges		Yes		Yes
Studs and nuts		Yes		Yes
CRDM head adapter tube		Yes	Yes	
Instrumentation tube		Yes	Yes	
Main nozzles		Yes		Yes
Nozzle safe ends		Yes	Yes	
Shell sections		Yes		Yes
Heads		Yes		Yes
Plates		Yes		Yes
Weldments				
Head and shell	Yes	Yes		Yes
CRDM head adapter to closure head connection			Yes	
Instrumentation tube to closure head connection			Yes	
Main nozzle	Yes	Yes		Yes
Cladding		Yes	Yes	
Nozzle to safe ends	Yes	Yes	Yes	
CRDM head adapter flange to CRDM head adapter tube	Yes		Yes	
All full-penetration ferritic pressure boundary welds accessible after hydrotest		Yes		Yes
Full-penetration nonferritic pressure boundary welds accessible after hydrotest a. Nozzle to safe ends		Yes	Yes	
Seal ledge				Yes
Head lift lugs				Yes
Core pad welds			Yes	

Notes:

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

Base metal weld repairs as a result of UT, MT, RT, and/or PT indications are cleared by the same nondestructive examination technique/procedure by which the indications were found. The repairs meet applicable Section III requirements.

In addition, UT examination in accordance with the in process/posthydro UT requirements is performed on base metal repairs in the core region and base metal repairs in the inservice inspection zone (1/2 T).

Table 5.3-3

END-OF-LIFE RT_{NDT} AND UPPER SHELF ENERGY PROJECTIONS

	Unirradiated		End-of-life (54 EFPY)	
	RT_{NDT} (°F)	USE (ft-lb)	USE (ft-lb) 1/4T	RT_{PTS} (°F)
Beltline Forging	-10	> 75	> 50	< 270(2)
Head	10	N/A	N/A	N/A
Flange	10	N/A	N/A	N/A
Weld	10	N/A	N/A	N/A
Beltline Weld	-20	> 75	> 50	< 300(2)

Notes:
1) The minimum unirradiated upper shelf energy for beltline base metal is for the transverse direction.
2) End-of-Life RT_{PTS} requirements shown. End-of-Life RT_{PTS} (also equals RT_{NDT}) will be determined for as-built material. The preliminary RT_{PTS} for the AP1000 reactor vessel beltline forging and beltline weld are 66°F and 98°F, respectively.

Table 5.3-4

REACTOR VESSEL MATERIAL SURVEILLANCE PROGRAM

Capsules U, V, W, X, Y, and Z			
Material	**Charpy**	**Tensile**	**1/2T-CT**
Limiting forging (long.)	30	4	6
Limiting forging (trans.)	30	5	6

Table 5.3-5

REACTOR VESSEL DESIGN PARAMETERS

(approximate values)	
Design pressure (psig)	2485
Design temperature (°F)	650
Overall height of vessel and closure head, bottom head outside diameter to top of control rod mechanism (ft-in.)	45-9
Number of reactor closure head studs	45
Diameter of reactor closure head/studs, (in.)	7
Outside diameter of closure head flange (in.)	188
Inside diameter of flange (in.)	148.81
Outside diameter at shell (in.)	176
Inside diameter at shell (in.)	159
Inlet nozzle inside diameter (in.)	22
Outlet nozzle inside diameter (in.)	31
Clad thickness, nominal (in.)	0.22
Lower head thickness, minimum (in.)	6
Vessel beltline thickness, minimum (in.)	8
Closure head thickness (in.)	6.25

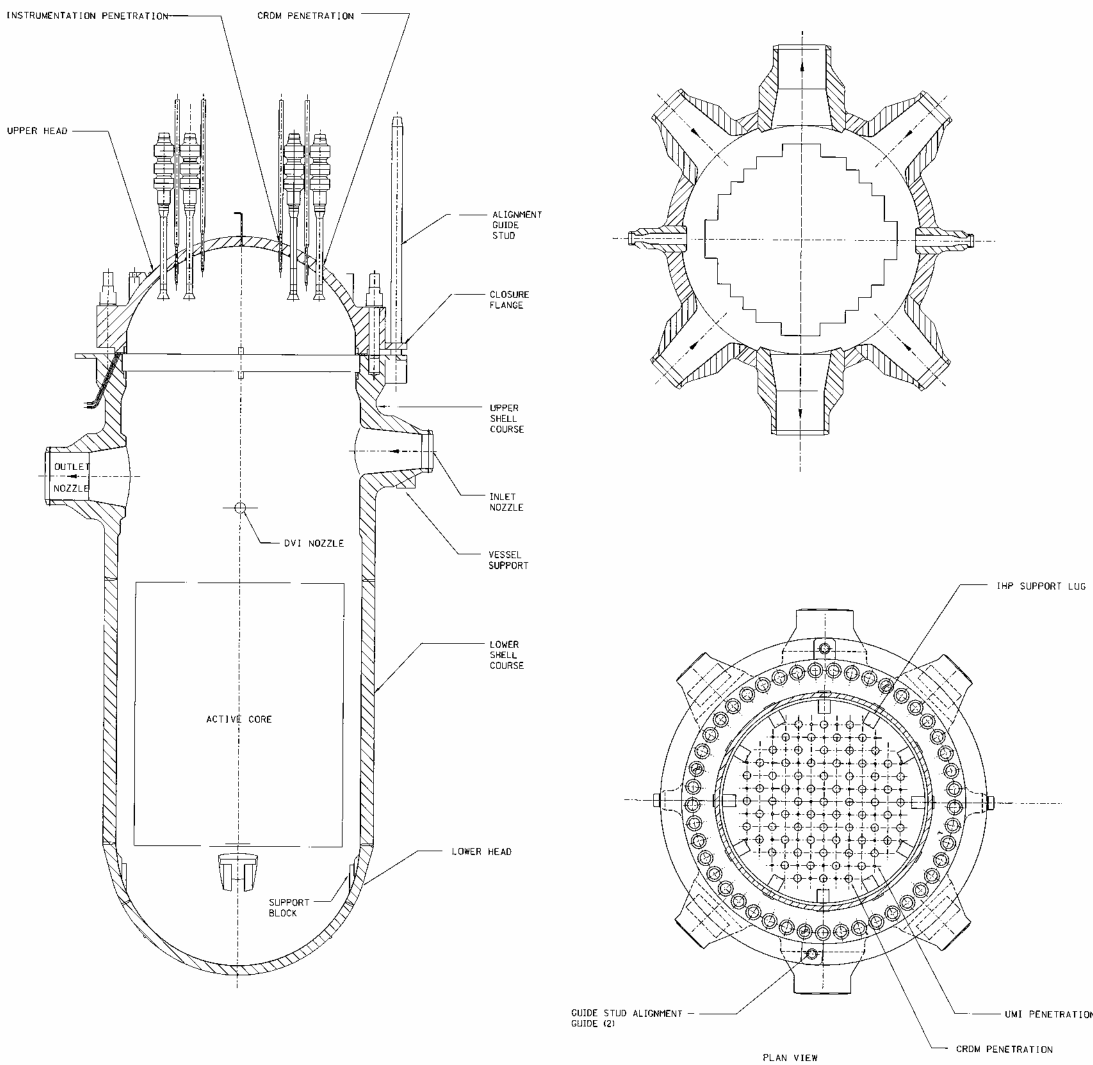


Figure 5.3-1

Reactor Vessel

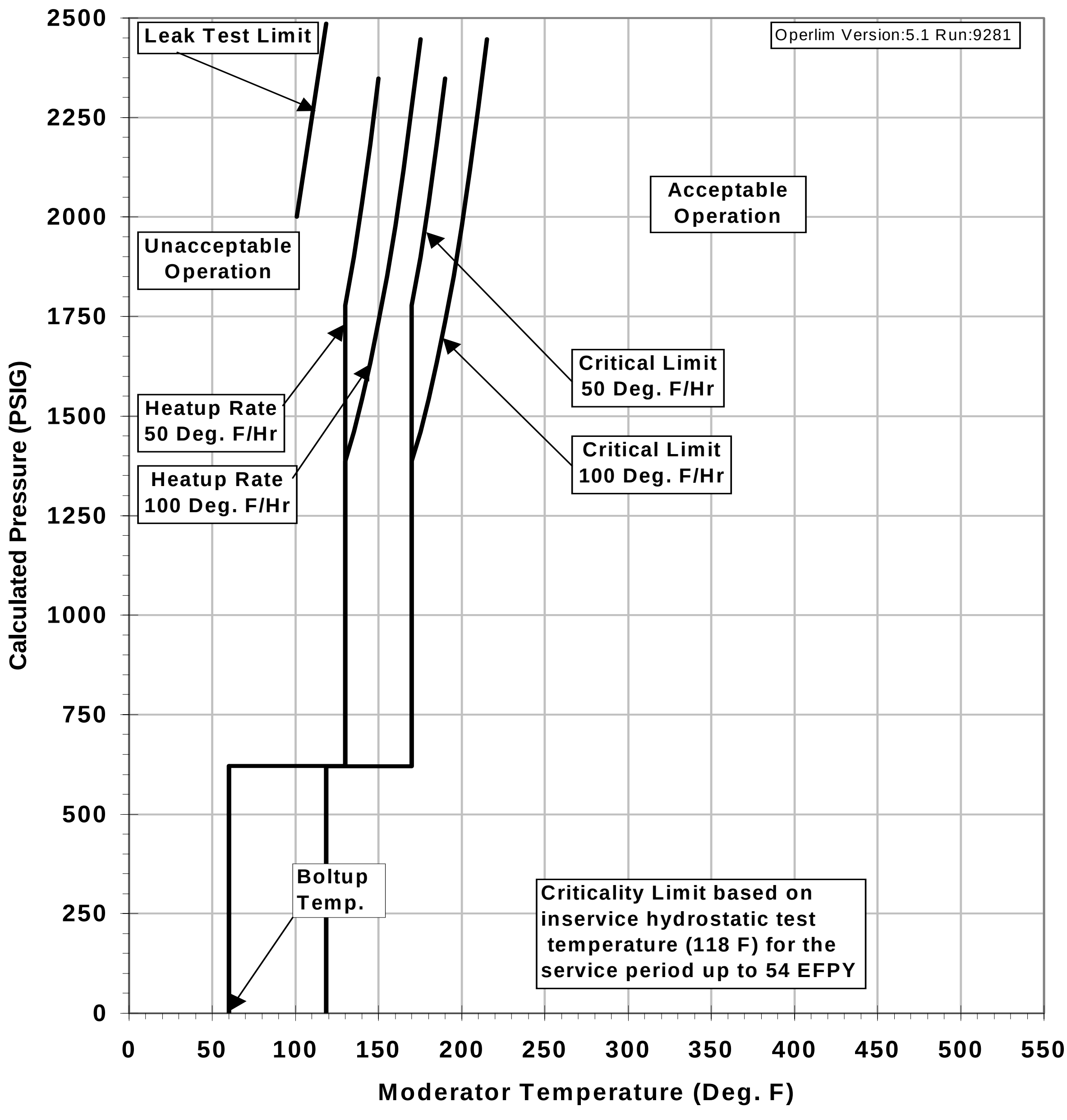


Figure 5.3-2

AP1000 Reactor Coolant System Heatup Limitations (Heatup Rate Up to 50° and 100°F/hour) Representative for the First 54 EFPY (Without Margins for Instrumentation Errors)

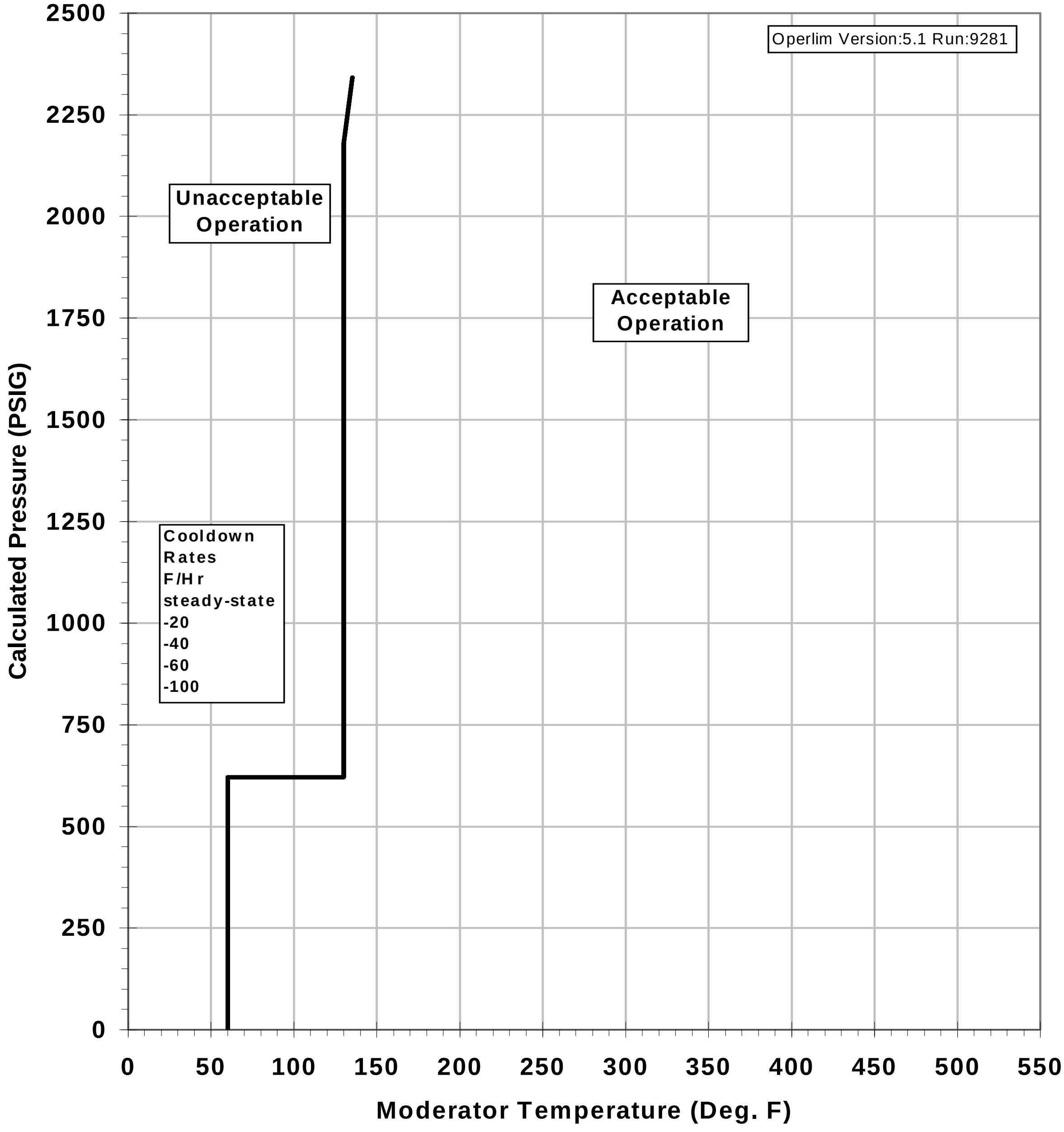


Figure 5.3-3

AP1000 Reactor Coolant System Cooldown Limitations (Cooldown Rates up to 50° and 100°F/hour) Representative for the First 54 EFPY (Without Margins for Instrumentation Errors)

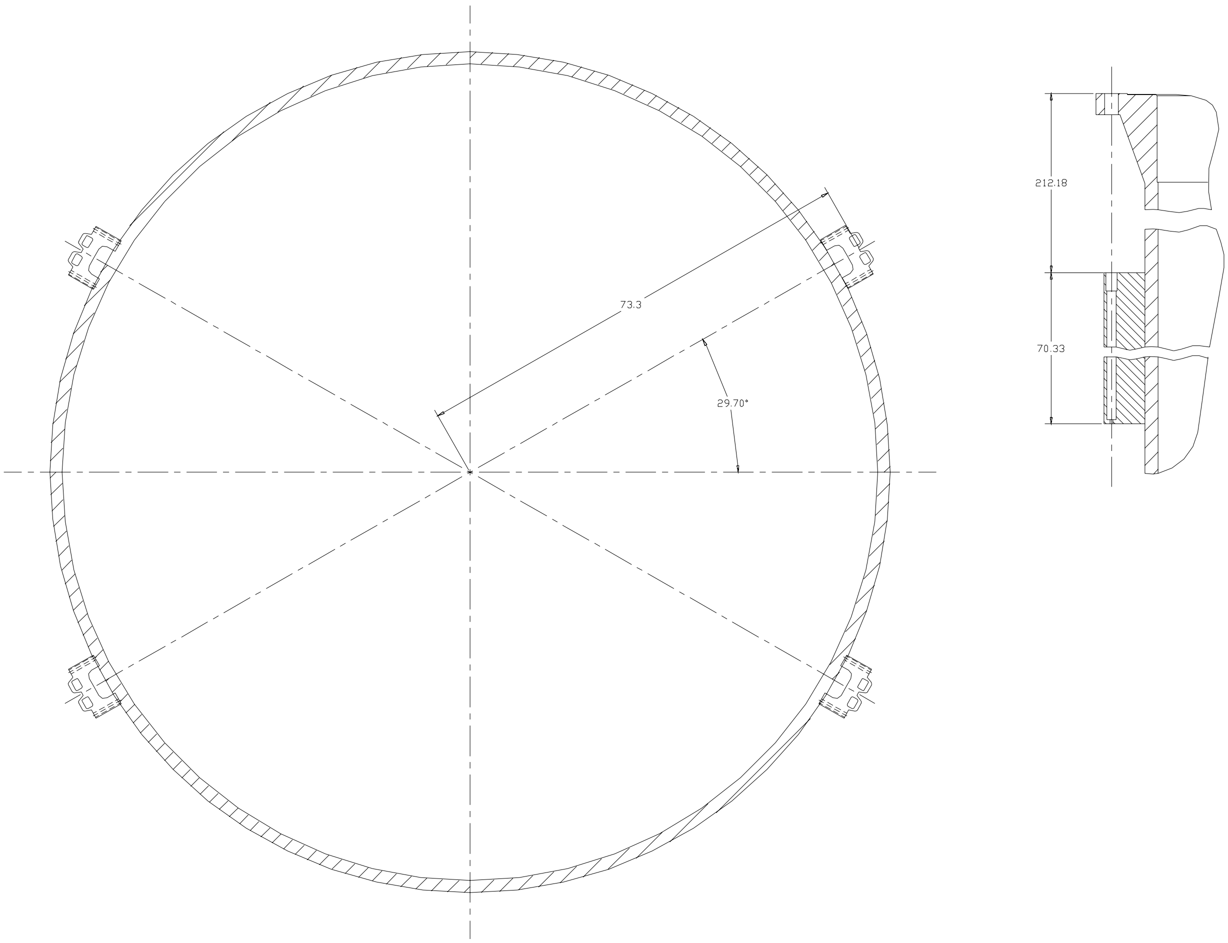


Figure 5.3-4

AP1000 Reactor Vessel Surveillance Capsules Locations

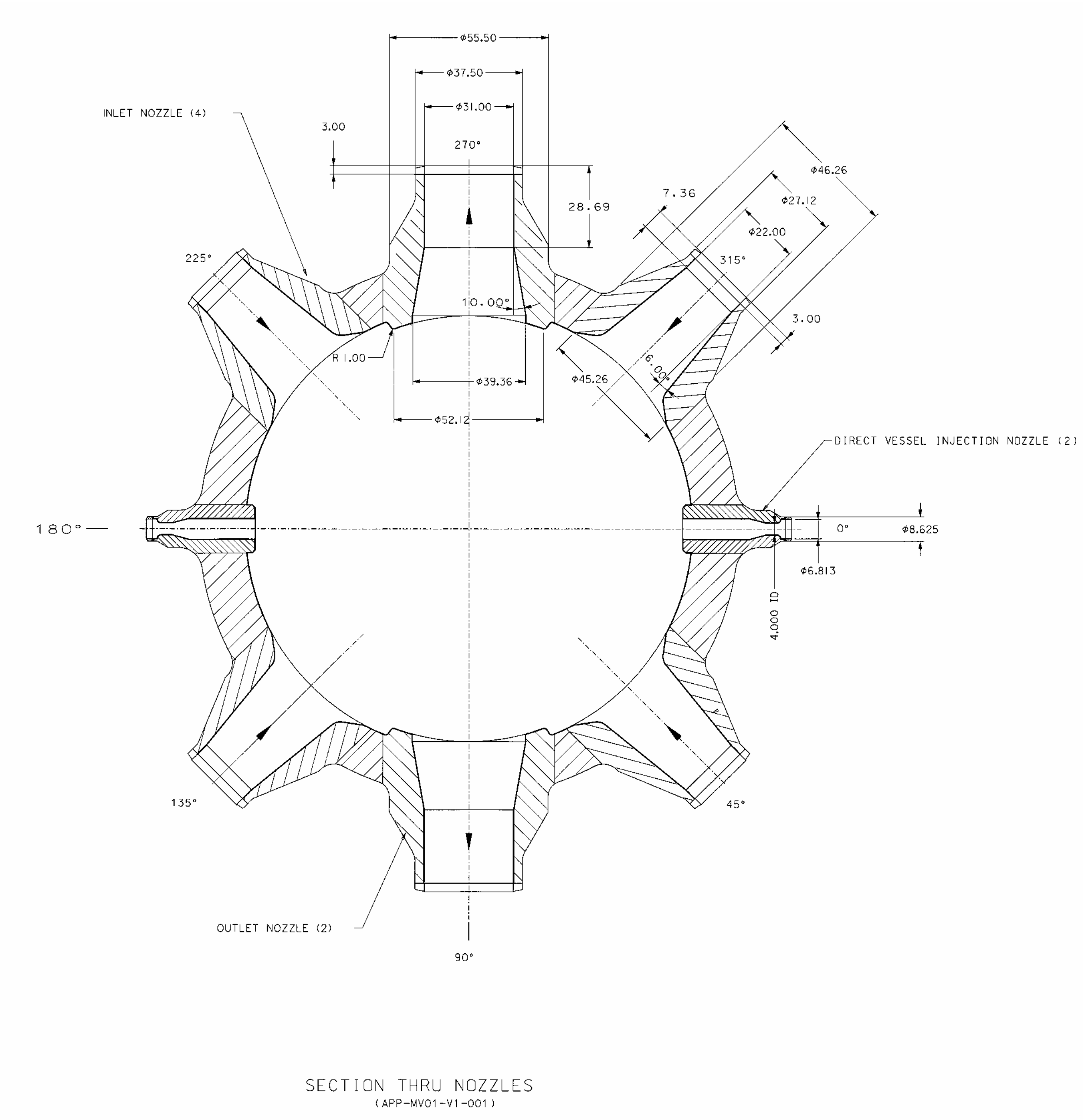


Figure 5.3-5

Reactor Vessel Key Dimensions
Plan View

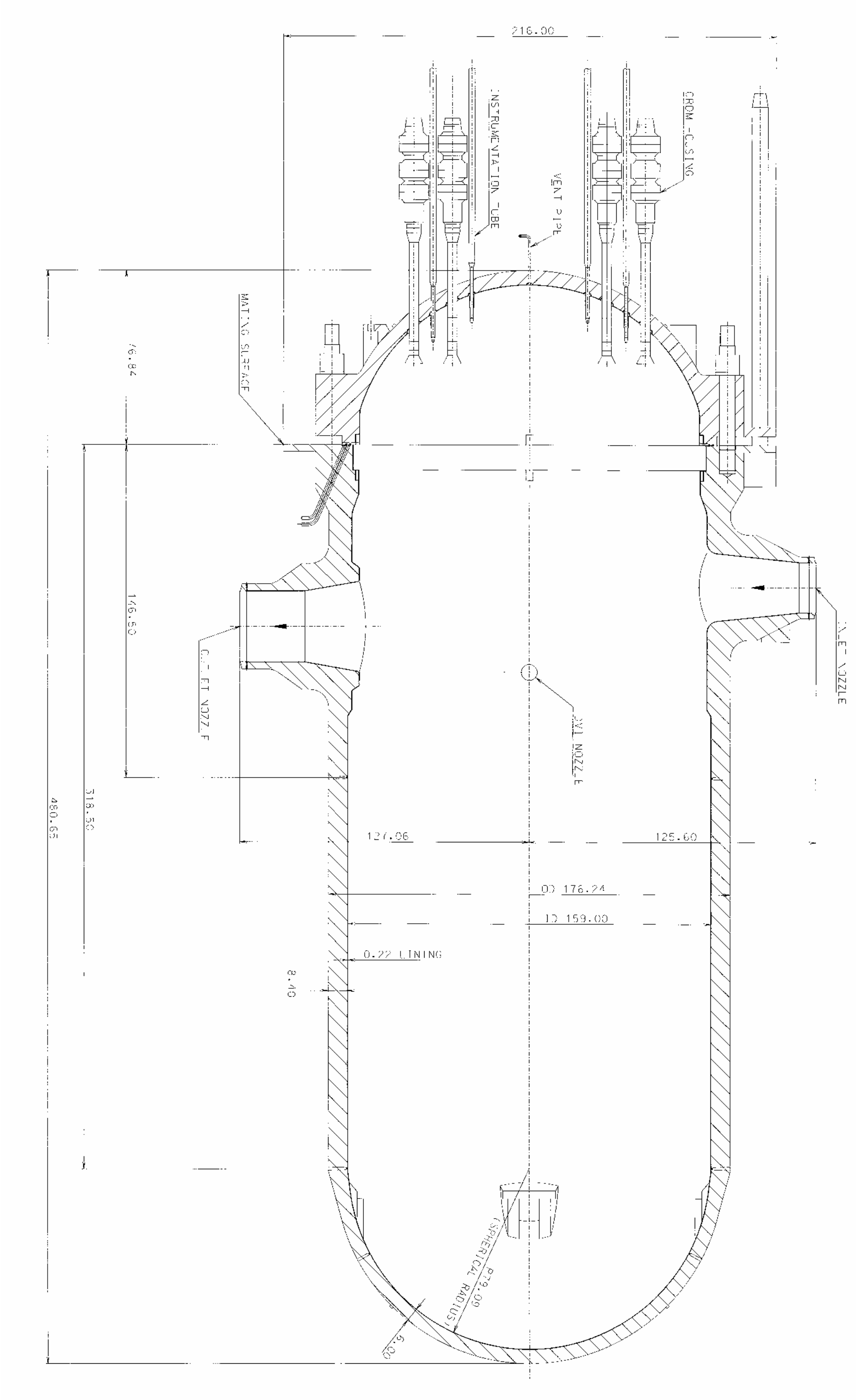


Figure 5.3-6

Reactor Vessel Key Dimensions, Side View

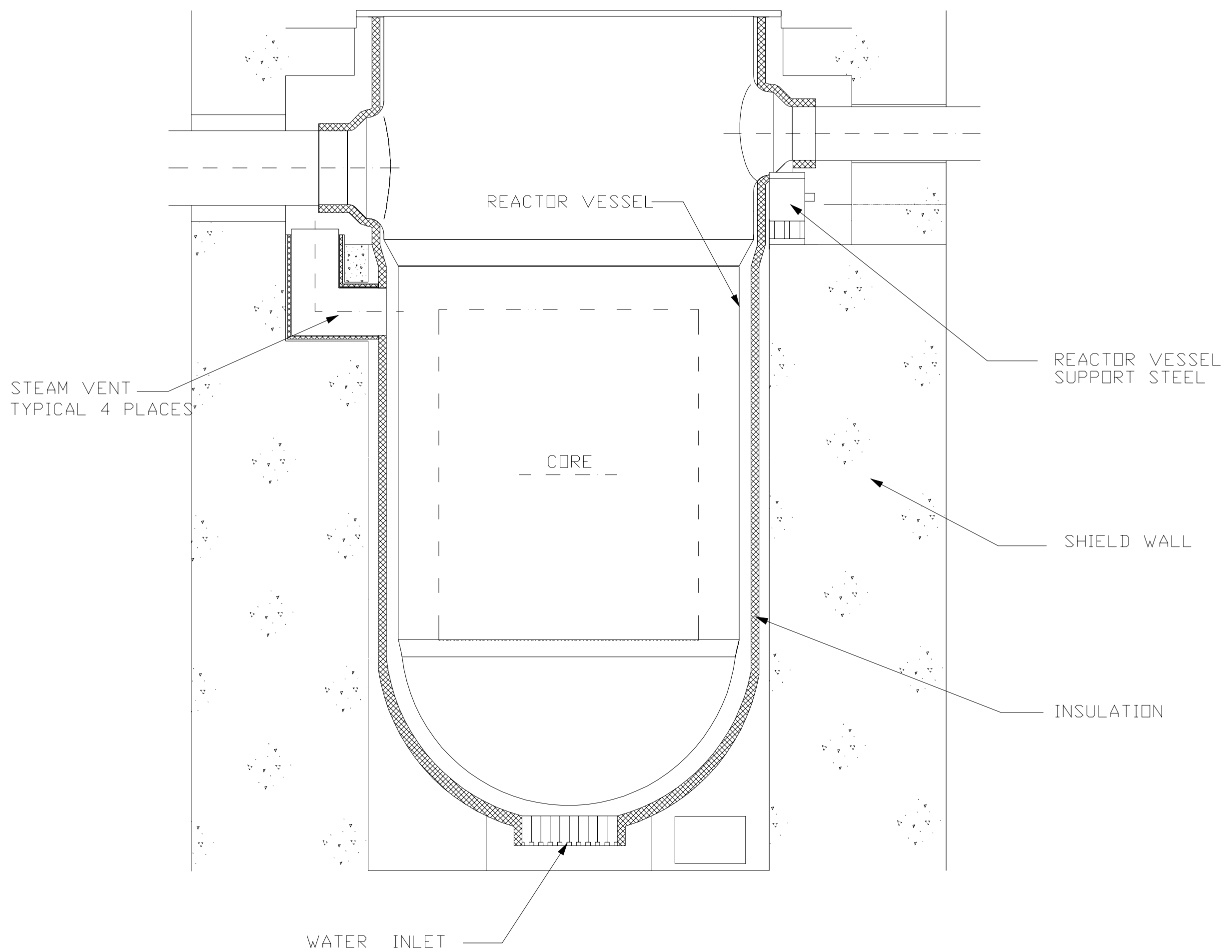


Figure 5.3-7

Schematic of Reactor Vessel Insulation

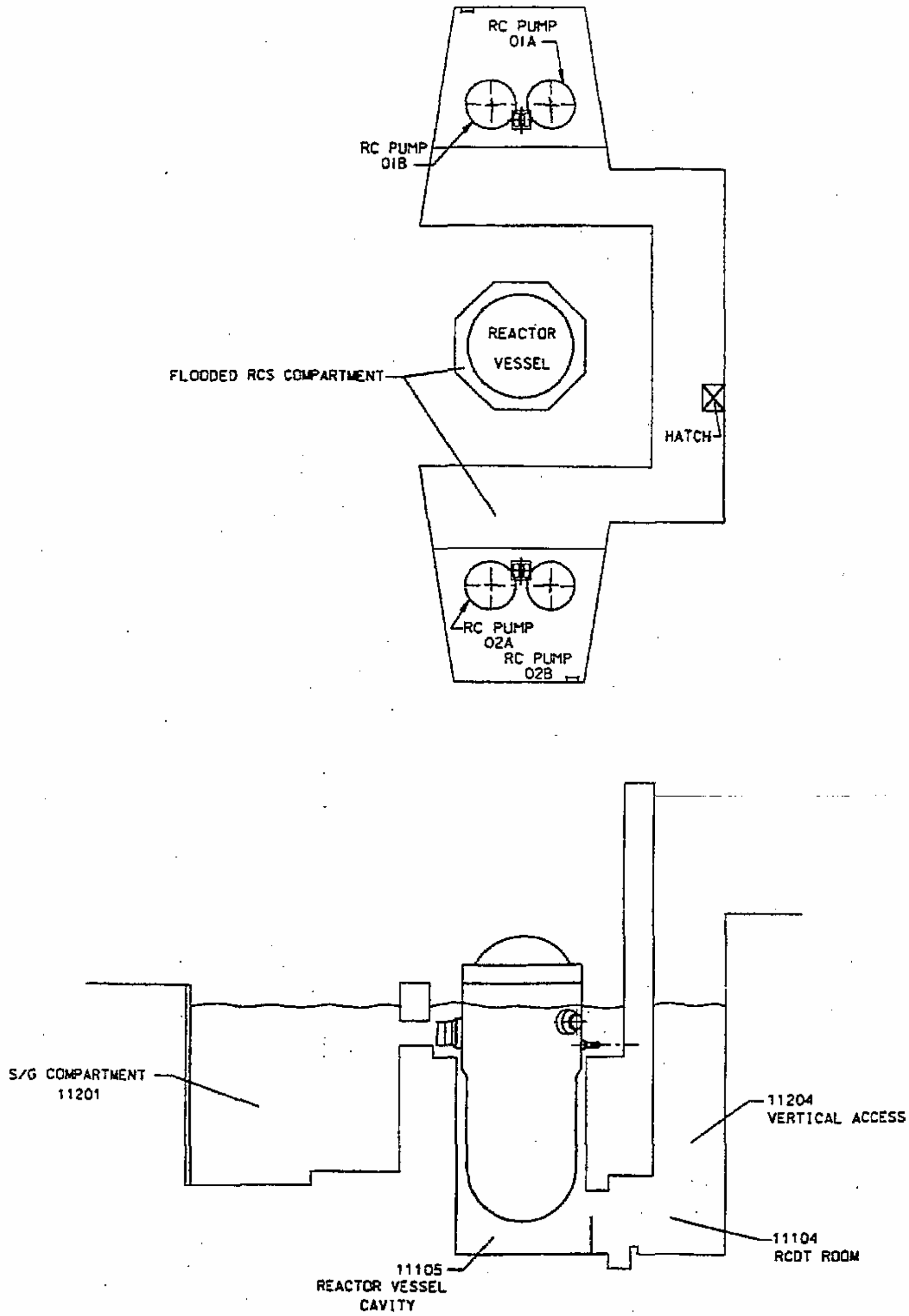


Figure 5.3-8

RCS Flooded Compartments During Ex-Vessel Cooling

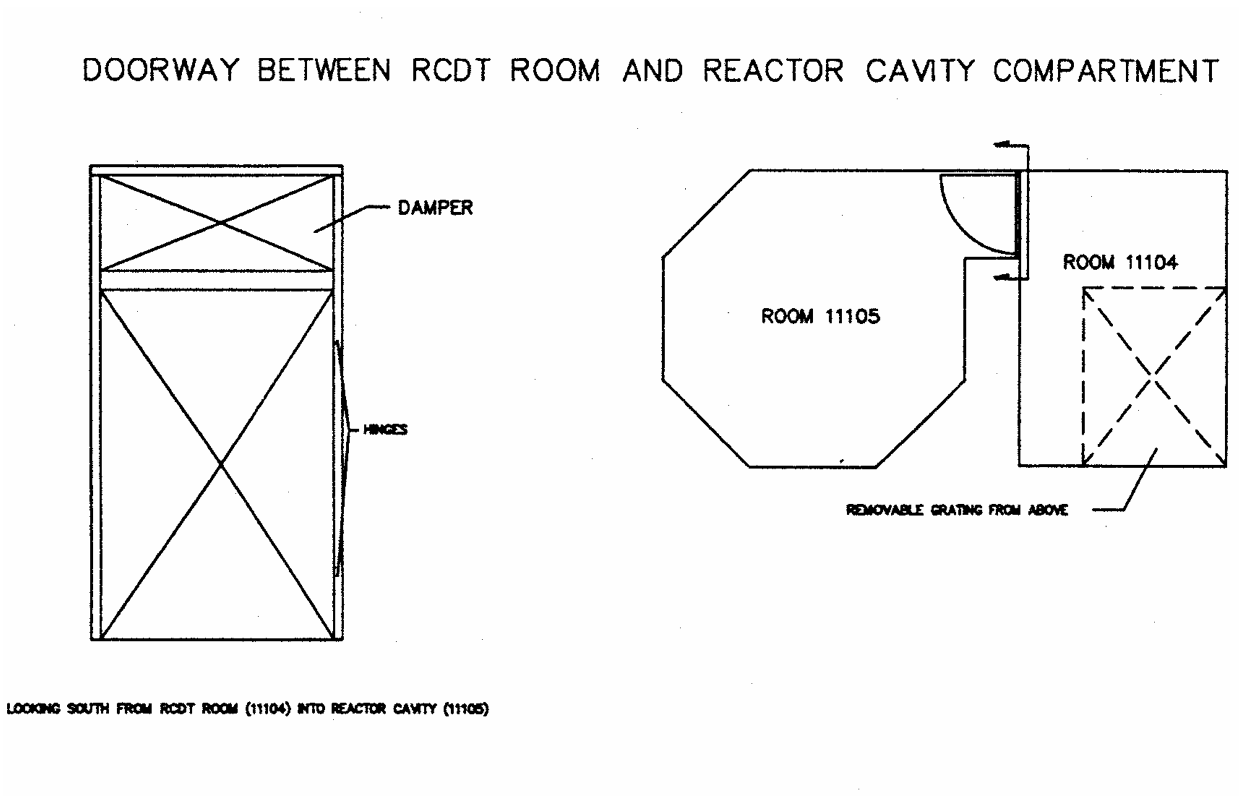


Figure 5.3-9

Door Between RCDT Room and Reactor Cavity Compartment

5.4 Component and Subsystem Design

5.4.1 Reactor Coolant Pump Assembly

5.4.1.1 Design Bases

The reactor coolant pump (RCP) is an integral part of the reactor coolant pressure boundary. It is designed, fabricated, erected, and tested to quality standards consistent with the requirements set forth in 10 CFR 50, 50.55a and General Design Criterion 1. The reactor coolant pump casing and stator shell provide a barrier to the release of reactor coolant and other radioactive materials to the containment atmosphere.

The reactor coolant pump provides an adequate core cooling flow rate for sufficient heat transfer to maintain a departure from nucleate boiling ratio (DNBR) greater than the limit established in the safety analysis. Pump assembly rotational inertia is provided by a flywheel (inside the pump pressure boundary) motor rotor, and other rotating parts. This rotational inertia provides flow during coastdown conditions. This forced flow following an assumed loss of offsite electrical power and the subsequent natural circulation effect in the reactor coolant system (RCS) adequately cools the core. The net positive suction head (NPSH) required for operation is by conservative pump design always less than that available by system design and operation.

The reactor coolant pump pressure boundary shields the balance of the reactor coolant pressure boundary from theoretical worst-case flywheel failures. The reactor coolant pump pressure boundary is analyzed to demonstrate that a fractured flywheel cannot breach the reactor coolant system boundary (stator shell, flange, and casing) and impair the operation of safety-related systems or components. This meets the requirements of General Design Criteria 4. The reactor coolant pump flywheel is designed, manufactured, and inspected to minimize the potential for the generation of high-energy fragments (missiles) under any anticipated operating or accident condition consistent with the intent of the guidelines set forth in Standard Review Plan Section 5.4.1.1 and Regulatory Guide 1.14. Each flywheel is tested at an overspeed condition to verify the flywheel design and construction.

5.4.1.2 Pump Assembly Description

5.4.1.2.1 Design Description

The reactor coolant pump is a single stage, hermetically sealed, high-inertia, centrifugal canned-motor pump. It pumps large volumes of reactor coolant at high pressures and temperature. Figure 5.4-1 shows the reactor coolant pump. Table 5.4-1 gives the design parameters.

A reactor coolant pump is directly connected to each of two outlet nozzles on the steam generator channel head. The two pumps on a steam generator turn in the same direction.

A canned motor pump contains the motor and all rotating components inside a pressure vessel. The pressure vessel consists of the pump casing, thermal barrier, stator shell, and stator cap, which are designed for full reactor coolant system pressure. The stator and rotor are encased in corrosion-resistant cans that prevent contact of the rotor bars and stator windings by the reactor coolant. Because the shaft for the impeller and rotor is contained within the pressure boundary,

seals are not required to restrict leakage out of the pump into containment. A gasket and canopy seal type connection between the pump casing, the stator flange, and the thermal barrier is provided. This design provides definitive leak protection for the pump closure. To access the internals of the pump and motor, the canopy seal weld is severed. When the pump is reassembled a canopy seal is rewelded. Canned-motor reactor coolant pumps have a long history of safe, reliable performance in military and commercial nuclear plant service.

The reactor coolant pump driving motor is a vertical, water-cooled, squirrel-cage induction motor with a canned rotor and a canned stator. It is designed for removal from the casing for inspection, maintenance and replacement, if required. The stator can protects the stator (windings and insulation) from the controlled portion of the reactor coolant circulating inside the motor and bearing cavity. The can on the rotor isolates the copper rotor bars from the system and minimizes the potential for the copper to plate out in other areas.

The motor is cooled by component cooling water circulating through a cooling jacket on the outside of the motor housing and through a thermal barrier between the pump casing and the rest of the motor internals. Inside the cooling jacket are coils filled with circulating rotor cavity coolant. This rotor cavity coolant is a controlled volume of reactor coolant that circulates inside the rotor cavity. After the rotor cavity coolant is cooled in the cooling jacket, it enters the lower end of the rotor and passes axially between the rotor and stator cans to remove heat from the rotor and stator.

Each pump motor is driven by a variable speed drive, which is used for pump startup and operation when the reactor trip breakers are open. When the reactor trip breakers are closed, the variable frequency drives are bypassed and the pumps run at constant speed.

A flywheel, consisting of two separate assemblies, provides rotating inertia that increases the coastdown time for the pump. Each flywheel assembly is a composite of a uranium alloy flywheel casting or forging contained within a welded nickel-chromium-iron alloy enclosure. The upper flywheel assembly is located between the motor and pump impeller. The lower assembly is located within the canned motor below the thrust bearing. Surrounding the flywheel assemblies are the heavy walls of the motor end closure, casing, thermal barrier flange, stator shell, or main flange.

The materials in contact with the reactor coolant and cooling water (with the exception of the bearing material) are austenitic stainless steel, nickel-chromium-iron alloy, or equivalent corrosion-resistant material.

There are two pump journal bearings, one at the bottom of the rotor shaft and the other between the upper flywheel assembly and the motor. The bearings are a hydrodynamic film-riding design. During rotor rotation, a thin film of water forms between the journal and pads, providing lubrication.

The thrust bearing assembly is at the bottom of the rotor shaft. The pivoted pad hydrodynamic bearing provides positive axial location of the rotating assembly regardless of operating conditions.

The reactor coolant pump is equipped with a vibration monitoring system that continuously monitors pump structure (frame) vibrations. Three-axis monitoring provides pump vibration information. The readout equipment includes warning alarms and high-vibration level alarms, as well as output for analytical instruments.

Four resistance temperature detectors (RTDs) monitor motor cooling circuit water temperature. These detectors provide indication of anomalous bearing or motor operation. They also provide a system for automatic shutdown in the event of a prolonged loss of component cooling water.

A speed sensor monitors rotor rpm's, which determines the load and direction of rotation. Additionally, voltage and current sensors provide information on motor load and electrical input.

5.4.1.2.2 Description of Operation

Reactor coolant is pumped by the main impeller. It is drawn through the eye of the impeller and discharged via the diffuser out through the radial discharge nozzle in the side of the casing. Once the motor housing is filled with coolant, the labyrinth seals around the shaft between the impeller and the thermal barrier minimize the flow of coolant into the motor during operation.

An auxiliary impeller at the lower part of the rotor shaft circulates a controlled volume of the coolant through the motor cooling coils. The coolant is cooled to about 150°F by component cooling water circulating around the cooling coils in the cooling jacket outside the stator shell. The cooled reactor coolant then passes through the annulus between the rotor and stator cans, where it removes heat from the rotor and stator and lubricates the motor's hydrodynamic bearings.

The variable frequency drives enable the startup of the reactor coolant pumps at slow speeds to decrease the power required from the pump motor during operation at cold conditions. The variable frequency drive provides operational flexibility during pump startup and reactor coolant system heatup. During a plant startup, the general startup procedure for the pumps is for the operator to start the pumps at a low speed. During reactor coolant system heatup, the pumps are run at the highest speed that is within the allowable motor current limits. As the reactor coolant temperature increases, the allowable pump speed also increases. Before the reactor trip breakers are closed, the variable frequency controllers are bypassed and the pumps run at constant speed.

During all power operations (Modes 1 and 2), the variable frequency drives are bypassed and the pumps run at constant speed.

5.4.1.3 Design Evaluation

5.4.1.3.1 Pump Performance

The reactor coolant pump is sized to deliver a flow rate that equals or exceeds the required flow rate. Testing prior to plant startup confirms the total delivery capability of the reactor coolant pump. See Section 14.2. Thus, adequate forced circulation coolant flow is confirmed prior to initial plant operation.

The required net positive suction head is provided with ample margin to provide operational integrity and minimize the potential for cavitation. The AP1000 does not require reactor coolant

pump operation to achieve safe shut down. Minimum net positive suction head requirements are not required to provide safe operation of the AP1000.

5.4.1.3.2 Overspeed Conditions

Reactor coolant pump overspeed can be postulated for either a fault in the connected electrical system that results in an increase in the frequency of the supplied current or due to a pipe rupture which results in an increase in the flow through the pump as the coolant exits the pipe.

For grid disconnect transients or turbine trips actuated by either the reactor trip system or the turbine protection system, the turbine overspeed control system acts to limit the reactor coolant pump overspeed. The turbine control system acts to rapidly close the turbine governor and intercept valves.

An electrical fault requiring immediate generator trip (with resulting turbine trip) will result in an overspeed condition in the electrically coupled reactor coolant pump no greater than that described previously for the grid disconnect/turbine trip transient.

Pump overspeed from high coolant flow rates associated with pipe rupture events are mitigated by the inertia of the pump, flywheel, and motor and by the connection of the motor to the electrical grid. Because of the application of mechanistic pipe break criteria, dynamic effects such as pump overspeed are not evaluated for breaks in piping in which leak-before-break is demonstrated.

5.4.1.3.3 Pressure Boundary Integrity

The pressure boundary integrity is verified for normal, anticipated transients, and postulated accident conditions. The pressure boundary components (pump casing, stator shell, stator cap, thermal barrier, and motor cooling coils) meet the requirements of the ASME Boiler and Pressure Vessel Code, Section III. These components are designed, analyzed, and tested according to the requirements in Paragraph NB-3400 of the ASME Code, Section III. Wells provided for resistance temperature detectors and speed sensor penetrations also satisfy the requirements of the ASME Code, Section III.

The motor terminals form part of the pressure boundary in the event of a stator-can failure. The ASME Code does not include criteria or methods for completely designing or analyzing such terminals. Motor terminals are designed, analyzed, and tested using criteria established and validated based on many years of service. Where applicable, ASME Code requirements and criteria are used. Individual terminals are hydrostatically tested and a high-pressure nitrogen test is performed on the finished stator assembly with the terminals installed.

5.4.1.3.4 Coastdown Capability

It is important to reactor protection that the reactor coolant continues to flow for a time after reactor trip and loss of electrical power. To provide this flow, each reactor coolant pump has a high-density flywheel and high-inertia rotor. The rotating inertia of the pump, motor, and flywheel is used during the coastdown period to continue the reactor coolant flow. The reactor coolant pump is designed for the safe shutdown earthquake. The coastdown capability of the pump is

maintained even for the case of loss of offsite and onsite electrical power coincident with the safe shutdown earthquake. Core flow transients and figures are provided in subsections 15.3.1 and 15.3.2.

A loss of component cooling water has no impact on coastdown capability. The reactor coolant pump can operate without cooling water until a safety-related pump trip occurs on high bearing water temperature. This prevents damage that could potentially affect coastdown.

The reactor trip system maintains the pump operation within the assumptions used for loss of coolant flow analyses. This also provides that adequate core cooling is provided to permit an orderly reduction in power if flow from a reactor coolant pump is lost during operation.

The reactor coolant pump coastdown occurs on a power loss to the plant. The following conditions are assumed to occur simultaneously:

- Reactor coolant system at normal operation temperature and pressure,
- Loss of cooling water,
- Loss of pump power,
- Reactor trip

If the stator can should leak during operation, the reactor coolant may cause a short in the stator windings. In such a case, the result would be the same as a loss of power to that pump. With either a rotor or a stator can failure, no fluid would be lost to the containment.

5.4.1.3.5 Bearing Integrity

The design requirements for the reactor coolant pump bearings provide long life with negligible wear. The vibration warning level and high-vibration level alarm set-points are, in part, based on evaluation of the effect of vibration on bearing life.

The bearings provide adequate stiffness to control shaft motion, protect the pump impeller and shaft labyrinths from wear, and avoid contact between the motor stator and rotor. The bearing loads are maintained within the load capabilities of hydrodynamic journal bearings even under the severe conditions experienced during seismic events. The bearing/shaft design and loadings are established by analysis and testing.

The frame vibration detectors provide indication of bearing performance. Control room indicators and alarms provide indication for operator action.

The bearing cooling provisions include a temperature monitoring system. The system operates continuously and has at least four redundant indicators per pump. Upon initiation of failure, the system indicates and alarms in the control room as a high bearing temperature. This requires pump shutdown. If these indications are ignored the pump trips when the high temperature setpoint is reached.

5.4.1.3.6 Integrity of Rotating Components

The rotating components of the pump and motor are analyzed for dynamic characteristics, including natural frequencies, stability, and forced responses to normal operation loads, and for several postulated fault conditions associated with the rotating masses. The fault conditions include seized rotor events, and integrity of the rotating components, including the flywheel.

5.4.1.3.6.1 Natural Frequency and Critical Speeds

The fundamental, undamped natural frequency of the reactor coolant pump rotating assembly is calculated for simple supports at the bearing locations and the rotor vibrating in air. This frequency, defined as the "classical lateral critical speed" (Reference 1) is greater than 125 percent of the normal operating speed.

Determination of the damped natural frequency of the reactor coolant pump rotor bearing system model includes the effects of the bearing films, can annular fluid interaction, motor magnetic phenomena, and pump structure. The damped natural frequencies for the AP1000 canned-motor pump exhibit sufficient energy dissipation to be stable. The high degree of damping provides smooth pump operation.

The pump is analyzed for the response of the rotor and stator to external forcing functions. The support and connection of the pump to the steam generator and piping are considered in the analysis. The responses are evaluated using criteria including critical loads, stress deformation, wear, and displacement limits to establish the actual system critical speeds.

5.4.1.3.6.2 Rotor Seizure

The design of the pump is such as to preclude the instantaneous stopping of any rotating component of the pump or motor for a canned motor of this type. The rotating inertia and power supplied to the motor would overcome interference between the impeller, bearings, flywheel assemblies, motor rotor, or rotor can and the surrounding components for a period of time. A change in the condition of any of the components sufficient to cause an interference would be indicated by the instrumentation monitoring speed, vibration, temperature, or current.

The reactor coolant system and canned-motor reactor coolant pump are analyzed for a locked rotor event. To analyze the mechanical and structural effects of a rapid slow down of the rotating assembly, a failure of the rotating assembly is postulated that results in deformation that causes an interference with the surrounding reactor coolant pump components. For such an interference, the pump and motor are postulated to come to a complete stop in a very short time period. This assumption bounds other postulated mechanisms for a rapid slowdown of the rotor, including impeller rub and rotor or stator can failure. The connection of the pump with the steam generator and discharge piping is analyzed for the vibration of the pump, hydraulic effects, and the torque due to the rapid slow down of the rotating assembly. The stresses in the pump casing, motor housing, steam generator channel head, and piping are analyzed using ASME Code, Section III, Service Level D limits for this condition.

The transient analysis of thermal and hydraulic effects of a postulated locked rotor event is based on a nonmechanistic, instantaneous stop of the impeller. This conservative assumption bounds any

slower stop and provides a comparison with the same analysis done for other nuclear power plants. The transient analysis considers the effect of the locked rotor on the reactor core and the reactor coolant system pressure. The results of the transient analysis are found in Chapter 15 and show that the reactor coolant system pressure does not exceed the system design pressure.

5.4.1.3.6.3 Flywheel Integrity

The canned-motor reactor coolant pump in the AP1000 complies with the requirement of General Design Criterion (GDC) Number 4. That Criterion states that components important to safety be protected against the effects of missiles.

The flywheel assemblies are located within and surrounded by the heavy walls of the motor end closure, casing, thermal barrier flange, stator shell, or main flange. In the event of a postulated worst-case flywheel assembly failure, the surrounding structure can, by a large margin, contain the energy of the fragments without causing a rupture of the pressure boundary. The analysis in Reference 10 of the capacity of the housing to contain the fragments of the flywheel is done using the energy absorption equations of Hagg and Sankey (Reference 2).

Compliance with the requirement of GDC 4 related to missiles can be demonstrated without reference to flywheel integrity, nevertheless, the intent of the guidelines of Regulatory Guide 1.14 is followed in the design and fabrication of the flywheel. The guidelines in Regulatory Guide 1.14 apply to steel flywheels. Since the uranium alloy of the AP1000 reactor coolant pump flywheel does not respond in the same manner as steel, many of the guidelines in the Regulatory Guide are not directly applicable.

The reactor coolant pump flywheel assemblies are fabricated from high-quality, depleted uranium alloy castings or forgings. Castings are poured using a process to minimize the formation of voids, cracks, or other flaws. The forging process is also controlled to minimize the formation of flaws. Subsequent to casting or forging, the flywheel is heat treated by solution annealing in a vacuum furnace and slowly cooled. This heat treatment minimizes the potential for residual stresses. The heat treatment process also removes hydrogen from the material to reduce the potential for hydrogen embrittlement.

The key parameters for the uranium alloy specification are defined in Table 5.4-2. These parameters include the minimum ultimate and yield tensile strength. Nil ductility transition and upper shelf energy are not specified in the requirements for the uranium alloy. These are characteristics of steel not duplicated in the uranium alloys. The material specification has appropriate testing to confirm that the fracture toughness used in the flywheel evaluation is satisfied. A Charpy V-notch test is required. A portion of the uranium is machined off to obtain specimens for tensile and impact tests and to inspect the microstructure.

The uranium is ultrasonically inspected following final machining. The acceptance criteria for the ultrasonic inspection are based on criteria in the ASME Code, Section III, and are done in conformance with the procedures outlined in ASTM-A-609 (Reference 3) with modifications as required for use with uranium alloy. Thermal methods are not used for finishing operations on the uranium. Following finishing operations on the casting the outside surface and the inside bore are subject to liquid penetrant inspections in conformance with the requirements of ASTM-E-165

(Reference 4). In-process controls used during the construction of the flywheel assemblies also provide for the quality of the completed assemblies.

The design speed of the flywheel is defined as 125 percent of the normal speed of the motor. The design speed envelopes all expected overspeed conditions. At the normal speed the calculated maximum primary stress in the uranium flywheel is less than one third of minimum yield strength. At the design speed the calculated maximum primary stress in the uranium flywheel is less than two thirds of minimum yield strength.

An analysis of the flywheel failure modes of ductile failure, nonductile failure and excessive deformation of the flywheel is performed to evaluate the flywheel design. The analysis is performed to determine that the critical flywheel failure speeds, based on these failure modes, are greater than the design speed. The critical flywheel failure speeds are not the same as the critical speed identified for the rotor. The critical flywheel failure speeds are greater than the design speed. The overspeed condition for a postulated pipe rupture accident is less than the critical flywheel failure speeds.

The uranium is sealed within a welded nickel-chromium-iron alloy enclosure to prevent contact with the reactor coolant or any other fluid. The enclosure minimizes the potential for corrosion of the flywheel and contamination of the reactor coolant with depleted uranium. The enclosure material specifications are ASTM-B-168 and ASTM-B-564. Even though the welds of the flywheel enclosure are not external pressure boundary welds, these welds are made using procedures and specifications that follow the rules of the ASME Code. A dye penetrant and ultrasonic test of the enclosure welds is performed in conformance with these requirements.

No credit is taken in the analysis of the flywheel missile generation for the retention of the fragments by the enclosure. A leak in the enclosure during operation could result in an out-of-balance flywheel assembly. A postulated small fracture of the flywheel casting inside the enclosure that does not penetrate or significantly deform the enclosure would also be expected to result in an out-of-balance condition. An out-of-balance flywheel exhibits an increase in vibration, which is monitored by vibration instrumentation.

The flywheel enclosure contributes only a small portion of the energy in a rotating flywheel assembly.

The outside ring, inside ring, and ends of the flywheel enclosure are connected together with flexible, full-penetration welds. The flexible welds and the local area adjacent to the welds may have stresses greater than the guidelines in the Standard Review Plan for normal and design speeds. The stress in the flexible welds and flywheel enclosure components for normal and design speeds are within the criteria in subsection NG of the ASME Code, which is used as a guideline.

Pipe rupture overspeed is based on a break of the largest branch line pipe connected to the reactor coolant system piping that is not qualified for leak-before-break criteria. The exclusion of the reactor coolant loop piping and branch line piping of 6 inches or larger size from the basis of the pump loss of coolant accident overspeed condition is based on the provision in GDC 4 to exclude dynamic effects of pipe rupture when a leak-before-break analysis demonstrates that appropriate criteria are satisfied. See subsection 3.6.3 for a discussion of leak-before-break analyses. The

criteria of subsection 3.6.2 are used to determine pipe break size and location for those piping systems that do not satisfy the requirements for mechanistic pipe break criteria.

In addition to material specification and non destructive testing requirement, each flywheel is subject to a spin test at 125 percent overspeed during manufacture. This demonstrates quality of the flywheel. Since the basis for the safety of the flywheel is retention of the fragments within the reactor coolant pump pressure boundary, periodic inservice inspections of the flywheel assemblies are not required to ensure that the basis for safe operation is maintained.

Because of the configuration of the flywheel assemblies, inservice inspection of the flywheel assemblies may not result in significant inspection results. Inspection of the uranium alloy casting would require removal of the assembly from the shaft, removal of the uranium from the enclosures, rewelding of the enclosure, reassembly, and balancing of the pump shaft. Opening of the pump assembly for a periodic inspection of the enclosure would result in an increased occupational radiation exposure and would not be consistent with goals relative to maintaining exposure as low as reasonably achievable. Also, opening the pump may increase the potential for entry of foreign objects into the canned motor area. For these reasons, routine, periodic inspection of the flywheel assemblies in the AP1000 canned motor reactor coolant pump is not recommended.

5.4.1.3.6.4 Other Rotating Components

The rotating components (other than the flywheel), including the impeller, auxiliary impeller, rotor, and rotor can, are evaluated for potential missile generation. In the event of fracture, the fragments from these components are contained by the surrounding pressure housing. The impeller is contained by the pump casing. The rotor and rotor can are contained by the stator, stator can, and motor housing. The auxiliary impeller is contained by the motor housing. In each case, the energy of the postulated fragments is less than that required to penetrate through the pressure boundary.

5.4.1.4 Tests and Inspections

Reactor coolant pump construction is subject to a quality assurance program. The pressure boundary components meet requirements established by the ASME Code. In addition, the flywheel is subject to quality assurance requirements. Table 5.4-3 outlines the inspection included in the reactor coolant pump quality assurance program.

The reactor coolant pump inservice inspection program is according to the ASME Code, Section XI.

The design enables disassembly and removal of the pump internals and canned motor for inspection of the pump casing or pressure boundary welds, as well as the bearings, flywheel assemblies, and other internal components, if required. As noted earlier, routine inspections of the impeller, flywheel, and motor internals are not required for safe operation of the pump.

5.4.1.4.1 Reactor Coolant System Flow Rate Verification

Initial verification of the reactor coolant system flow rate is made during the plant initial test program. Reactor coolant system flow rates are measured during the pre-core load hot functional tests, and during the startup tests. The objective of these tests is to verify that the reactor coolant system flow rate meets the flow rate range of Technical Specification 3.4.1.

After the pre-core reactor coolant system flow rate measurement is taken, analytical adjustments are made to the pre-core measured reactor coolant system flow rate to predict a post-core reactor coolant system flow rate. Calculations of the reactor coolant system flow rate with and without the core are performed. The calculation of the pre-core load reactor coolant system flow rate is compared with results of the pre-core load flow testing, and this information will be used in the calculation of the post-core load reactor coolant system flow rate as appropriate. The predicted post-core load reactor coolant system flow rate is checked to verify that it satisfies Technical Specification 3.4.1. Verifications are also made that the post-core reactor coolant system flow rates satisfy Technical Specification 3.4.1 flow limits during startup testing.

5.4.2 Steam Generators

5.4.2.1 Design Bases

The steam generator channel head, tubesheet, and tubes are a portion of the reactor coolant pressure boundary. The tubes transfer heat to the steam system while retaining radioactive contaminants in the primary system. The steam generator removes heat from the reactor coolant system during power operation and anticipated transients and under natural circulation conditions. The steam generator heat transfer function and associated secondary water and steam systems are not required to provide a safety-related safe shutdown of the plant.

The steam generator secondary shell functions as containment boundary during operation and during shutdown when access opening closures are in place.

Tables 5.4-4 and 5.4-5 give steam generator design data. AP1000 equipment, seismic and ASME Boiler and Pressure Vessel Code classifications of the steam generator components are discussed in Section 3.2. ASME Code and Code Case compliance are discussed in subsection 5.2.1. The ASME Code classification for the secondary side is specified as Class 2. The pressure-retaining parts of the steam generator, including the primary and secondary pressure boundaries, are designed to satisfy the criteria specified in Section III of the ASME Code for Class 1 components.

Subsection 3.9.3 discusses the design stress limits, loads, and combined loading conditions. Subsection 3.9.1 discusses the transient conditions applicable to the steam generator. The number of transients is based on 60 years of operation.

In addition to the loading conditions associated with pressure and temperature variations for transient and anticipated accident conditions, the steam generator is evaluated for fluid borne and structural vibration originating with the reactor coolant pump. The steam generator is also evaluated for the load on the primary outlet nozzles resulting from a postulated locked reactor coolant pump rotor. See subsection 5.4.1.3.6 for a discussion of the locked rotor postulation.

Chapter 11 gives estimates of radioactivity levels anticipated in the secondary side of the steam generators during normal operation and the bases for the estimates. Chapter 15 discusses the accident analysis of a steam generator tube rupture.

The water chemistry on the primary side, selected to provide the necessary boron content for reactivity control, should minimize corrosion of reactor coolant system surfaces. The effectiveness of the water chemistry in the control of the secondary side corrosion is discussed in Chapter 10. Compatibility of steam generator tubing with both primary and secondary coolants is discussed further in subsection 5.4.2.4.3.

The steam generator is designed to minimize the potential for mechanical or flow-induced vibration. Tube support adequacy is discussed in subsection 5.4.2.3.3. The tubes and tubesheet are analyzed and confirmed to withstand the maximum accident loading conditions defined in subsection 3.9.3. Further consideration is given in subsection 5.4.2.3.4 to the effect of tube-wall thinning on accident condition stresses.

5.4.2.2 Design Description

The AP1000 steam generator is a vertical-shell U-tube evaporator with integral moisture separating equipment. Figure 5.4-2 shows the steam generator, indicating several of its design features.

The design of the Model Delta-125 steam generator, except for the configuration of the channel head, is similar to an upgraded Model Delta-75 steam generator. The Delta-75 steam generator has been placed in operation as a replacement steam generator.

Steam generator design features are described in the following paragraphs.

On the primary side, the reactor coolant flow enters the primary chamber via the hot leg nozzle. The lower portion of the primary chamber is elliptical and merges into a cylindrical portion, which mates to the tubesheet. This arrangement provides enhanced access to all tubes, including those at the periphery of the bundle, with robotics equipment. This feature enhances the ability to inspect, replace and repair portions of the AP1000 unit compared to the more spherical primary chamber of earlier designs. The head is divided into inlet and outlet chambers by a vertical divider plate extending from the apex of the head to the tubesheet.

The reactor coolant flow enters the inverted U-tubes, transferring heat to the secondary side during its traverse, and returns to the cold leg side of the primary chamber. The flow exits the steam generator via two cold leg nozzles to which the canned-motor reactor coolant pumps are directly attached. A high-integrity, nickel-chromium-iron (Alloy 690) weld is made to the nickel-chromium-iron alloy buttered ends of these nozzles.

A passive residual heat removal (PRHR) nozzle attaches to the bottom of the channel head of the loop 1 steam generator on the cold leg portion of the head. This nozzle provides recirculated flow from the passive residual heat removal heat exchanger to cool the primary side under emergency conditions. A separate nozzle on one of the steam generator channel heads is connected to a line from the chemical and volume control system. The nozzle provides for purification flow and makeup flow from the chemical and volume control system to the reactor coolant system.

The AP1000 steam generator channel head has provisions to drain the head. To minimize deposits of radioactive corrosion products on the channel head surfaces and to enhance the decontamination of these surfaces, the channel head cladding is machined or electropolished for a smooth surface. The primary manways provide enhanced primary chamber access compared to previous model steam generators.

Should steam generator replacement using a channel head cut be required, the arrangement of the AP1000 steam generator channel head facilitates steam generator replacement in two ways. It is completely unobstructed around its circumference for mounting cutting equipment. And is long enough to permit post-weld heat treatment with minimal effect of tubesheet acting as a heat sink.

The tubes are fabricated of nickel-chromium-iron Alloy 690. The tubes undergo thermal treatment following tube-forming operations. The tubes are tack-expanded, welded, and hydraulically expanded over the full depth of the tubesheet. Westinghouse has used this practice in F-type steam generators. It was selected because of its capability to minimize secondary water access to the tube-to-tube-sheet crevice. Residual stresses smaller than from other expansion methods result from this process and are minimized by tight control of the pre-expansion clearance between the tube and tubesheet hole.

Support of the tubes is provided by ferritic stainless steel tube support plates. The holes in the tube support plates are broached with a hole geometry to promote flow along the tube and to provide an appropriate interface between the tube support plate and the tube. Figure 5.4-3 shows the support plate hole geometry. Anti-vibration bars installed in the U-bend portion of the tube bundle minimize the potential for excessive vibration.

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. The feedwater enters a feedring via a welded thermal sleeve connection and leaves it through nozzles attached to the top of the feedring. The nozzles are fabricated of an alloy that is very resistant to erosion and corrosion with the expected secondary water chemistry and flow rate through the nozzles. After exiting the nozzles, the feedwater flow mixes with saturated water removed by the moisture separators. The flow then enters the downcomer annulus between the wrapper and the shell.

Fluid instabilities and water hammer phenomena are important considerations in the design of steam generators. Water level instabilities can occur from density wave instabilities which could affect steam generator performance. Density wave instability is avoided in the AP1000 steam generator by including appropriate pressure losses in the downcomer and the risers that lead to negative damping factors.

Steam generator bubble collapse water hammer has occurred in certain early pressurized water reactor steam generator designs having feedrings equipped with bottom discharge holes. Prevention and mitigation of feedline-related water hammer has been accomplished through an improved design and operation of the feedwater delivery system. The AP1000 steam generator and feedwater system incorporate features designed to eliminate the conditions linked to the occurrence of steam generator water hammer. The steam generator features include introducing feedwater into the steam generator at an elevation above the top of the tube bundle and below the

normal water level by a top discharge feedring. The top discharge of the feedring helps to reduce the potential for vapor formation in the feedring. This minimizes the potential for conditions that can result in water hammer in the feedwater piping. The feedwater system features (subsection 10.4.7 discusses in more detail) designed to prevent and mitigate water hammer include a short, horizontal or downward sloping feedwater pipe at steam generator inlet.

These features minimize the potential for trapping pockets of steam which could lead to water hammer events.

Stratification and striping are reduced by an upturning elbow inside the steam generator which raises the feedring relative to the feedwater nozzle. The elevated feedring reduces the potential for stratified flow by allowing the cooler, more dense feedwater to fill the nozzle/elbow arrangement before rising into the feedring.

The potential for water hammer, stratification, and striping is additionally reduced by the use of a separate startup feedwater nozzle. The startup feedwater nozzle is located at an elevation that is just below the main feedwater nozzle and is rotated circumferentially away from the main feedwater nozzle. A startup feedwater spray system independent of the main feedwater feedring is used to introduce startup feedwater into the steam generator. The layout of the startup feedwater piping includes the same features as the main feedwater line to minimize the potential for waterhammer. The startup feedwater system is used to introduce water into the secondary side of the steam generator as described in subsection 10.4.7.2.3.

At the bottom of the wrapper, the water is directed toward the center of the tube bundle by the lowest tube support plate. This recirculation arrangement serves to minimize the low-velocity zones having the potential for sludge deposition.

As the water passes the tube bundle, it is converted to a steam-water mixture. Subsequently, the steam-water mixture from the tube bundle rises into the steam drum section, where centrifugal moisture separators remove most of the entrained water from the steam. The steam continues to the secondary separators, or dryers, for further moisture removal, increasing its quality to a designed minimum of 99.75 percent (0.25 percent by weight maximum moisture). Water separated from the steam combines with entering feedwater and recirculates through the steam generator. A sludge collector located amidst the inner primary separator risers provides a preferred region for sludge settling away, from the tubesheet and tube support plates. The dry, saturated steam exits the steam generator through the outlet nozzle, which has a steam-flow restrictor. (See subsection 5.4.4.)

5.4.2.3 Design Evaluation

Integrity of the pressure retaining function of the steam generator is provided by compliance with the ASME Code. The evaluation of the stress levels and fatigue usage for the steam generator pressure boundary is calculated for the specified loading conditions and demonstrates that the values are less than the allowable limits. These calculations are documented in a stress report as required by the ASME Code. Corrosion allowances which are consistent with material erosion/corrosion resistance and service environment (velocity, chemistry, etc.) are employed throughout the design.

Meeting the heat transfer requirements and tube vibration and tube wall integrity requirements in addition to the ASME Code requirements is discussed in the following subsections:

5.4.2.3.1 Forced Convection

The steam generator transfers to the secondary coolant loop the heat generated during power operation in the reactor and by the reactor coolant pumps. The evaluation of the steam generator thermal performance, including required heat transfer area and steam flow, uses conservative assumptions for parameters such as primary flow rates and heat transfer coefficients. The effective heat transfer coefficient is determined by the physical characteristics of the AP1000 steam generator and the fluid conditions in the primary and secondary systems for the nominal 100 percent design case. It includes a conservative allowance for fouling and uncertainty. Tables 5.4-4 and 5.4-5 show the nominal design requirements and parameters. Table 5.1-1 lists additional parameters used to evaluate the steam generator design.

5.4.2.3.2 Natural Circulation Flow

When the normal feedwater supply is not available, water may be supplied to the steam generators by the startup feedwater system. The startup feedwater system is a nonsafety-related system that provides a nonsafety-related source of decay heat removal. In addition, the system is used during startup and shutdown and other times when the normal feedwater system is not available.

When the steam generator is supplied with water from the startup feedwater system, the steam generator has enough surface area and a small enough primary-side hydraulic resistance to remove decay heat from the reactor coolant by natural circulation without operation of the reactor coolant pumps.

If the passive residual heat removal system activates, the passive residual heat removal nozzle connection to the steam generator passes coolant flow from the passive residual heat removal heat exchanger into the cold leg side of the channel head. Coolant is drawn through the reactor coolant pumps into the cold legs and then into the reactor vessel.

5.4.2.3.3 Mechanical and Flow-Induced Vibration under Normal Operating Conditions

Potential sources of tube excitation are considered, including primary fluid flow within the U-tubes, mechanically induced vibration, and secondary fluid flow on the outside of the U-tubes. The effects of primary fluid flow and mechanically induced vibration, including those developed by the canned-motor pump, are acceptable during normal operation. The primary source of potential tube degradation due to vibration is the hydrodynamic excitation of the tubes by the secondary fluid. This area has been emphasized in both analyses and tests, including evaluation of steam generator operating experience.

Three potential tube vibration mechanisms related to hydrodynamic excitation of the tubes have been identified and evaluated. These include potential flow-induced vibrations resulting from vortex shedding, turbulence, and fluid-elastic vibration mechanisms.

Nonuniform, two-phase turbulent flow exists throughout most of the tube bundle. Therefore, vortex shedding is possible only for the outer few rows of the inlet region. Moderate tube response

caused by vortex shedding is observed in some carefully controlled laboratory tests on idealized tube arrays. However, no evidence of tube response caused by vortex shedding is observed in steam generator scale model tests simulating the inlet region. Bounding calculations consistent with laboratory test parameters confirmed that vibration amplitudes would be acceptably small, even if the carefully controlled laboratory conditions were unexpectedly reproduced in the steam generator.

Flow-induced vibrations due to flow turbulence are also small: Root mean square amplitudes are less than allowances used in tube sizing. These vibrations cause stresses that are two orders of magnitude below fatigue limits for the tubing material. Therefore, neither unacceptable tube wear nor fatigue degradation due to secondary flow turbulence is anticipated.

Tube fluid elastic excitation is potentially more significant than either vortex shedding or turbulence. Relatively large tube amplitudes can feed back proportionally large tube driving forces if an instability threshold is exceeded. Tube support spacing, in both the tube support plates in the straight leg region and the anti-vibration bars in the U-bend region, provides tube response frequencies such that the instability threshold is not exceeded. This approach provides large margins against initiation of fluid elastic vibration for tubes effectively supported by the tube support system.

Small clearances between the tubes and the supporting structure are required for steam generator fabrication. These clearances introduce the potential that any given tube support location may not be totally effective in restraining tube motion if there is a finite gap around the tube at that location. Fluid-elastic tube response within available support clearances is therefore theoretically possible if secondary flow conditions exceed the instability threshold when no support is assumed at the location with a gap around the tube. This potential has been investigated both with tests and analyses for both the U-bend and straight leg regions.

AP1000 steam generator tube wear potential is expected to be within available design margins even for limiting tube fit-up conditions, based on previous experience. The AP1000 steam generator includes a number of features that minimize the potential for tube wear at tube supports and antivibration bars. Provisions to minimize the potential for wear include optimal spacing between the tube supports and the configuration of the anti-vibration bar assemblies. Tube wear is minimized in the tube support plate design by the configuration of the broached hole through the support plate, the surface finish of the broached hole in the tube support plate, the clearance between the tube and the hole in the tube support plate, and tube support plate material selection.

Tube bending stresses corresponding to tube vibration response remain more than two orders of magnitude below fatigue limits as a consequence of vibration amplitudes constrained by the tube supports. These analyses and tests for limiting postulated fit-up conditions include simultaneous contributions from flow turbulence.

As outlined, analyses and tests demonstrate that unacceptable tube degradation resulting from tube vibration is not expected for the AP1000 steam generators. Operating experience with steam generators having the same size tubes and similar flow conditions supports this conclusion.

The U-bend fatigue (discussed in NRC Bulletin 88-02) is not a consideration in the AP1000 steam generators. The mechanism considered in Bulletin 88-02 requires denting of the top tube support plate. But this is not expected with the stainless steel tube support plates in the AP1000 steam generator. Additionally, the location of anti-vibration bars is controlled by in-process dimensional inspection.

5.4.2.3.4 Allowable Tube Wall Thinning under Accident Conditions

An evaluation determined 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 short enough duration that there is no endurance issue to be considered.

The steam generator tubes, existing originally at their minimum wall thickness and reduced by a conservative general corrosion and erosion loss, provide an adequate safety margin (sufficient wall thickness) in addition to the minimum required for a maximum stress less than the allowable stress limit, as defined by the ASME Code.

Studies have been made on AP1000 sized tubing under accident loadings. The results show that the maximum Level D Service condition stress due to combined pipe rupture and safe shutdown earthquake loads is less than the allowable limit. The tube thickness required to achieve the acceptable stress is less than the minimum AP1000 steam generator tube wall thickness, which is reduced to account for assumed general corrosion and erosion rate. Thus, an adequate safety margin is exhibited. The general corrosion rate is based on a conservative weight-loss rate for Alloy 690 TT tubing in flowing, 650°F primary-side reactor coolant fluid. The estimated weight loss, based on testing when equated to a thinning rate and projected over a 60-year design objective, is much less than the assumed corrosion allowance of 3 mils. This leaves the remainder of the general corrosion allowance for thinning on the secondary side.

5.4.2.4 Steam Generator Materials

5.4.2.4.1 Selection and Fabrication of Materials

The pressure boundary materials used in the steam generator are selected and fabricated in accordance with the requirements of Section II and III of the ASME Code. Subsection 5.2.3 contains a general discussion of material specifications. Table 5.2.3-1 lists the types of materials. Fabrication of reactor coolant pressure boundary materials is also discussed in subsection 5.2.3, particularly in subsections 5.2.3.3 and 5.2.3.4.

Industry-wide corrosion testing and specification development programs have justified the selection of thermally treated Alloy 690, a nickel-chromium-iron alloy (ASME SB-163), for the steam generator tubes. The channel head divider plate is also Alloy 690 (ASME SB-168). The interior surfaces of the reactor coolant channel head, nozzles, and manways are clad with austenitic stainless steel. The primary side of the tubesheet is weld clad with nickel-chromium-iron alloy (ASME SFA-5.14). The tubes are then seal welded to the tubesheet cladding. These fusion welds, comply with Sections III and IX of the ASME Code. The welds are dye-penetrant inspected and leak-tested before each tube is hydraulically expanded the full depth of the tubesheet bore.

Nickel-chromium-iron alloy in various forms is used for parts where high velocities could otherwise lead to erosion/corrosion. These include the nozzles on the feedwater ring, startup feedwater sparger, and some primary separator parts.

Subsection 5.2.1 discusses authorization for use of ASME Code cases used in material selection. Subsection 1.9.1 discusses 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.

During manufacture, the primary and secondary sides of the steam generator are cleaned according to written procedures following 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 ASME NQA-2. Onsite cleaning and cleanliness control also follow the guidance of Regulatory Guide 1.37 (discussed in subsection 1.9.1). Cleaning process specifications are discussed in subsection 5.2.3.4.

Subsection 5.2.3.3 discusses the fracture toughness of the materials. Adequate fracture toughness of ferritic materials in the reactor coolant pressure boundary is provided by compliance with 10 CFR 50, Appendix G, Fracture Toughness Requirements, and Paragraph NB-2300 of Section III of the ASME Code.

The heat and lot of tubing material for each steam generator tube is recorded and documented as part of the quality assurance records. Archive samples of each heat and lot of steam generator tubing material are provided to the Combined License applicant for use in future materials testing programs or as inservice inspection calibration standards. A minimum of 7 feet of tubing in the final heat treat condition is supplied.

The exterior of the steam generator surface may be submerged following a postulated actuation of the automatic depressurization system (ADS). During this event, water may be present on the outside of the steam generator without affecting the heat transfer or pressure boundary capabilities of the AP1000 steam generator.

5.4.2.4.2 Steam Generator Design Effects on Materials

Several features in the AP1000 steam generator minimize crevice areas and the deposition of contaminants from the secondary-side flow. Such crevices and deposits could otherwise produce a local environment allowing potential chemical concentration and material corrosion.

The portion of the tube within the tubesheet is expanded hydraulically to close the crevice between the tube and tubesheet. The length of the expansion is carefully controlled to minimize the potential of an over-expanded condition above the tubesheet and to minimize the extent of unexpanded tube at the top of the tubesheet.

The tube support plates are made of corrosion resistant Type 405 stainless steel alloy. A three-lobed, or trifoil, tube hole design provides flow adjacent to the tube outer surface. This provides high sweeping velocities at the tube and tube support plate intersections. The trifoil tube support plate provides in-plane and out-of-plane strength. The sweeping velocities through the support plate reduce sludge accumulation in the tube-to-tube support crevices. Figure 5.4-3 shows

the trifoil broached holes. This support plate design contributes to a high circulation ratio. The increased flow from a high circulation ratio circulation results in increased flow in the interior of the bundle, as well as horizontal velocity across the tubesheet, which reduces the tendency for sludge deposition.

The effect of the total bundle flow on the vibrational stability of the tube bundle has been analyzed, with consideration given to flow-induced excitation frequencies. The maximum unsupported span length of tubing in the U-bend region and the optimal number of anti-vibration bars has been determined, using advanced statistical techniques and vibration modeling. The anti-vibration bars are fabricated from wide strips of Type 405 stainless steel. The construction minimizes the gaps between the anti-vibration bars and tubes.

Additional measures in the AP1000 steam generator design minimize areas of dryout in the steam generator and sludge accumulations in low-velocity areas. The wrapper design results in significant water velocities across the tubesheet.

A high capacity blowdown system is capable of continuous blowdown of the steam generators at a moderate volume and intermittent flow. The intakes of the blowdown system is at the tube bundle periphery.

A passive sludge collector, which provides a low flow settling zone, is in the upper shell region located among the inner primary moisture separator risers. The sludge collector, or mud drum, provides a location for particulate to settle remote from the tubesheet and tube support plates. The mud drum can be cleaned during a plant shutdown.

Several methods can be used to clean operating steam generators of secondary-side deposits. Sludge lancing is a procedure in which a hydraulic jet inserted through an access opening (handhole) loosens deposits and the loose material is flushed out of the steam generator. Four 6 inch access ports are provided for sludge lancing, inspection of the tube bundle by portable inspection equipment, and retrieval of loose objects. They are located above the tubesheet 90° apart (two on the tubelane and two at 90° from the tube lane) to provide access to the secondary face of the tubesheet. Also, two 4-inch ports located on the secondary shell in line with the tubelane and above the top tube support plate provide access to the U-Bend area. A blowdown hole, located at the bottom of the secondary side drain channel permits continuous blowdown and monitoring of secondary water chemistry. The materials of the secondary side of the steam generator are also compatible with chemical cleaning.

5.4.2.4.3 Compatibility of Steam Generator Tubing with Primary and Secondary Coolants

The industry corrosion tests mentioned in subsection 5.4.2.4.1, subjected the steam generator tubing material thermally treated Alloy 690 ASME SB-163, to simulated steam generator water chemistry. These tests indicated that the loss due to general corrosion over the 60-year operating design objective is small 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 indicate that Alloy 690 TT provides as good or better corrosion resistance as either Alloy 600 TT or nickel-iron-chromium Alloy 800. Alloy 690 TT also resists general corrosion in severe operating water conditions.

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

The all volatile treatment (AVT) control program minimizes the possibility of the tube wall thinning phenomenon. Successful AVT operation requires maintenance of low concentrations of impurities in the steam generator water. This reduces the potential for formation of highly concentrated solutions in low-flow zones, which is a precursor of corrosion. By restricting the total alkalinity in the steam generator and prohibiting extended operation with free alkalinity, the all volatile treatment program minimizes the possibility for intergranular corrosion in localized areas due to excessive levels of free caustic.

Laboratory testing shows that Alloy 690 TT tubing is compatible with the AVT environment. Isothermal corrosion testing in high-purity water shows that Alloy 690 TT exhibiting normal microstructure tested at normal engineering stress levels is not susceptible to intergranular stress corrosion cracking in extended exposure to high-temperature water. These tests also show that no general type corrosion occurred. Field experience with Alloy 690 TT tubing in operation since 1989 has been excellent.

Model boiler tests evaluate similar AVT chemistry guidelines adopted by Westinghouse and EPRI. Conformance to the guidelines enhances tube corrosion performance. The secondary water chemistry guidelines for AP1000 are found in Chapter 10. Action levels for secondary side water chemistry during power operation are given in Table 10.3.5-1. Extensive operating data has been accumulated for all volatile treatment chemistry.

A comprehensive program of steam generator inspections, including the recommendations of Regulatory Guide 1.83, Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes, with the exceptions as stated in subsection 1.9.1, provides for detection of any degradation that might occur in the steam generator tubing.

Included with the standard operating condition water chemistry controls are chemistry controls during zero power (including shutdown, no-load, heatup, cooldown, and refueling operations). The startup feedwater nozzle may be used to supply hydrazine, ammonia, and other chemicals to control secondary pH and oxygen during wet layup. This nozzle, in combination with the blowdown line, can also be used to remove sensible heat from the steam generator during cooldown. Sparging the steam generator with nitrogen through the blowdown line also promotes secondary recirculation at zero power. This recirculation can be used, in conjunction with the addition of cleaning agents into the secondary side, to remove magnetite, copper, or other deposited contaminants. The AP1000 steam generator is also configured for pressure pulse cleaning and water slap methods to remove deposits on the secondary side.

High margins against primary water stress corrosion cracking exist with the specification of thermally treated Alloy 690 tubing. Alloy 690 TT is resistant to primary water stress corrosion cracking over the range of anticipated operating environments. The tubing is thermally

treated according to a laboratory-derived treatment process and is generally consistent with industry-accepted and EPRI procedures.

The tube support plates are fabricated of ferritic stainless steel. Laboratory tests show that this material is resistant to corrosion in the AVT environment. If corrosion of ferritic stainless steel were to occur because of the concentration of contaminants, the volume of the corrosion products is essentially equivalent to the volume of the parent material consumed. This would be expected to preclude denting. The support plates are also designed with trifoil tube holes rather than cylindrical holes. The trifoil tube hole (see Figure 5.4-3) design promotes high velocity flow along the tube and is expected to minimize the accumulation of impurities at the support plate location.

5.4.2.5 Steam Generator Inservice Inspection

The steam generator is designed to permit inspection of pressure boundary parts, including individual tubes. Preservice inspection of the AP1000 steam generators is performed according to the ASME Code. Inservice inspection complies with the requirements of 10 CFR 50.55a.

The design includes a number of openings to provide access to both the primary and secondary sides of the steam generator. The openings include four 18-inch diameter manways, one for access to each chamber of the reactor coolant channel head and two in the steam drum for inspection and maintenance of the upper shell internals. In addition, four 6-inch diameter handholes in the shell, located just above the tubesheet secondary surface are provided. Two 4-inch diameter inspection openings are provided at each end of the tubelane between the upper tube support plate and the row 1 tubes. Additional access to the tube bundle U-bend is provided through the internal deck plate at the bottom of the primary separators. For proper functioning of the steam generator, some of the deck-plate openings are covered with hatch plates welded in place that are removable by grinding, gouging, or other methods to cut off the welds.

Regulatory Guide 1.83 provides recommendations on the inspection of tubes. The recommendations cover inspection equipment, baseline inspections, tube selection, sampling and frequency of inspection, methods of recording, and required actions based on findings. Any eddy current inspection performed in the manufacturing facility is conducted by personnel qualified to the requirements for inspectors performing inservice inspection of operating units. The manufacturing facility inspection is conducted using the same equipment as, or equipment similar to, that used during inservice inspection of operating units. Exceptions to Regulatory Guide 1.83 are noted in subsection 1.9.1.

The steam generators permit access to tubes for inspection, repair, or plugging, if necessary, per the guidelines described in Regulatory Guide 1.83. Tooling to install mechanical and welded plugs, tube repair sleeves, or effect other repair processes remotely can be delivered robotically. The AP1000 steam generator includes features to enhance robotics inspection of steam generator tubes without manned entry of the channel head. These include a cylindrical section of the channel head, primary manways, and provisions to facilitate the remote installation of nozzle dams. Computer simulation using designs of existing robotically delivered inspection and maintenance equipment verifies that tubes can be accessed. To facilitate tube identification for manual activities, the tube location for a large fraction of the tubes is scribed on the tubesheet.

The minimum requirements for inservice inspection of steam generators, including tube repair criteria, are the responsibility of the Combined License applicant considering NRC requirements and industry recommendations. The steam generator tube integrity is verified in accordance with a Steam Generator Tube Surveillance Program. The Steam Generator Tube Surveillance Program is the responsibility of the Combined License applicant. Section XI of the ASME Code provides general acceptance criteria for indications of tube degradation in the steam generator.

5.4.2.6 Quality Assurance

The steam generator is constructed to a quality assurance program that meets the requirements of the ASME Code and ANSI/ASME NQA-1 and NQA-2. Table 5.4-6 outlines the testing included in the steam generator quality assurance program.

The radiographic inspection and acceptance standard comply with the requirements of Section III of the ASME Code per applicable Code Year and Addenda.

Liquid penetrant inspection and acceptance standards comply with the requirements of Section III of the ASME Code per applicable Code Year and Addenda. Liquid penetrant inspection is performed on weld-deposited tubesheet cladding, channel head cladding, divider-plate-to-tubesheet and to channel head weldments, tube-to-tubesheet weldments, and weld-deposit cladding.

Magnetic particle inspection and acceptance standards comply with the requirements of Section III of the ASME Code per applicable Code Year and Addenda. Magnetic particle inspection is performed on the tubesheet forging, channel head forging, nozzle forging, and the following weldments:

- Nozzle to shell (if not integral)
- Support brackets
- Instrument connection (secondary)
- Temporary attachments, after removal
- Accessible pressure retaining welds after hydrostatic test

Ultrasonic inspection and acceptance standards comply with the requirements of Section III of the ASME Code per applicable Code Year and Addenda. Ultrasonic tests are performed on the tubesheet forgings, tubesheet cladding, secondary shells and heads plates and forgings, and nozzle forgings.

The heat transfer tubing is subjected to eddy current testing and ultrasonic examination.

Hydrostatic tests comply with Section III of the ASME Code.

Non-destructive examination of pressure boundary and associated weldments will be performed in accordance with the applicable Code Year and Addenda of ASME Section III, Subsections NB and NC.

5.4.3 Reactor Coolant System Piping

5.4.3.1 Design Bases

The reactor coolant system piping accommodates the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions. The piping in the reactor coolant system is AP1000 equipment Class A (ANS Safety Class 1, Quality Group A) (see subsection 3.3.2) and is designed and fabricated according to ASME Code, Section III, Class 1 requirements. Lines with a 3/8-inch or less flow restricting orifice qualify as AP1000 equipment Class B (ANS Safety Class 2, Quality Group B) and are designed and fabricated with ASME Code, Section III, Class 2 requirements. If one of these lines breaks, the chemical volume control charging pumps are capable of providing makeup flow while maintaining pressurizer water level. Stresses are maintained within the limits of Section III of the ASME Code. Code and material requirements are provided in Section 5.2. Inservice inspection of Class 1 components is discussed in subsection 5.2.4.

Materials of construction are specified to minimize corrosion/erosion and to provide compatibility with the operating environment including the expected radiation level. The welding, cutting, heat treating and other processes used to minimize sensitization of stainless steel are discussed in subsection 5.2.3.

The thickness of reactor coolant system piping satisfies the design requirements of the ASME Code, Section III, Subsection NB. The analysis of piping of nominal pipe size of 6 inches or greater which demonstrates leak-before-break characteristics, as outlined in subsection 3.6.3, does not include loads due to the dynamic effects of pipe rupture. The minimum pipe bend radius is 1.5-nominal pipe diameters, and ovality meets the requirements of the ASME Code.

Butt welds, branch connection nozzle welds, and boss welds are of a full-penetration design. Flanges conform to ANSI B16.5. Socket weld fittings and socket joints conform to ANSI B16.11.

5.4.3.2 Design Description

5.4.3.2.1 Piping Elements

The reactor coolant system piping includes those sections of reactor coolant hot leg and cold leg piping interconnecting the reactor vessel, steam generators, and reactor coolant pumps. It also includes piping connected to the reactor coolant loop piping and primary components. Figure 5.1-5 shows the Piping and Instrumentation Drawing (P&ID) of the reactor coolant system. The boundary of the reactor coolant system includes the second of two isolation or shut off valves and the piping between those valves. A single ASME Code safety valve may also represent the boundary of the reactor coolant system. The connected piping in the reactor coolant system includes the following:

- Chemical and volume control system (CVS) purification return line from the system isolation valve up to a nozzle on the steam generator channel head
- Chemical and volume control system purification line from the branch connection on the pressurizer spray line to the system isolation valve

- Pressurizer spray lines from the reactor coolant cold legs up to the spray nozzle on the pressurizer vessel
- Normal residual heat removal system (RNS) pump suction line from one reactor coolant hot leg up to the designated isolation valve
- Normal residual heat removal system discharge line from the designated check valve to the connection to the core makeup tank return lines to the reactor vessel direct injection nozzle
- Accumulator lines from the designated check valve to the reactor vessel direct injection nozzle
- Passive core cooling system (PXS) lines from the cold legs to the core make-up tanks and back to the reactor vessel direct injection nozzles
- Drain, sample and instrument lines to the designated isolation valve.
- Pressurizer surge line from one reactor coolant loop hot leg to the pressurizer vessel surge nozzle
- Pressurizer spray scoop, reactor coolant temperature element installation boss, and the temperature element well itself
- All branch connection nozzles attached to reactor coolant loops
- Pressure relief lines in the pressurizer safety and relief valve module from nozzles on top of the pressurizer vessel up to and including the pressurizer safety valves
- Automatic depressurization system (ADS) lines from the pressurizer relief lines to the stages 1, 2, and 3 automatic depressurization system valves
- Automatic depressurization system lines from the connection with the hot leg up to the fourth stage valves
- Auxiliary spray line from the isolation valve up to the main pressurizer spray line
- Passive core cooling system lines from the hot leg to the passive residual heat removal heat exchanger, and back to the nozzle on the steam generator channel head
- Vent line from the reactor vessel head to the system isolation valves
- In-containment refueling water storage tank injection lines from the designated valves to the reactor vessel direct injection nozzle

Table 5.4-7 gives principal design data for the reactor coolant piping.

A discussion of the codes used in the fabrication of reactor coolant piping and fittings appears in Section 5.2.

Reactor coolant system piping is fabricated of austenitic stainless steel. The piping is forged seamless without longitudinal or electroslag welds. It complies with the requirements of the ASME Code, Section II (Parts A and C), Section III, and Section IX. The reactor coolant system piping does not contain any cast fittings. Changes in direction are accomplished in most cases using bent pipe instead of elbows to minimize the number of welds, fittings, and short radius turns.

5.4.3.2.2 Piping Connections

Joints and connections are welded, except for the pressurizer safety valves, the reactor head vent line, miscellaneous vents and drains, and orifice flanges, where flanged joints are used. Fillet welds may be used to connect small instrument lines to socket weld connections. Piping connections for auxiliary systems are above the horizontal centerline of the reactor coolant loop piping, except for the following:

- The residual heat removal pump suction line, which is located at the bottom of a hot leg pipe. This enables the water level in the reactor coolant system to be lowered in the reactor coolant loop pipe while continuing to operate the residual heat removal system, should this be required for maintenance.

- The pressurizer level channel nozzles with a 0.375-inch or less flow restrictor and the hot leg level channel nozzle with a 0.375-inch flow restrictor located in the hot leg piping.

- The sample connection located at 45 degrees below the horizontal centerline of each hot leg.

- The cold leg-narrow range thermowells attached at the horizontal centerline.

- The wide-range thermowell tap and three of the six narrow-range thermowell taps in each hot leg.

5.4.3.2.3 Encroachment into Coolant Flow

Parts encroaching into the primary coolant loop flow path are limited to the following:

- 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.

- The narrow-range and wide-range temperature detectors are in resistance temperature detector wells that extend into both the hot and cold legs of the reactor coolant loop piping.

5.4.3.3 Design Evaluation

The loading combinations, stress limits, and analytical methods for the structural evaluation of the reactor coolant system piping and supports for design conditions, normal conditions, anticipated transients, and postulated accident conditions are discussed in subsection 3.9.3. The requirements for dynamic testing and analysis are discussed in subsection 3.9.2. The reactor coolant system design transients for normal operation, anticipated transients and postulated accident conditions are discussed in subsection 3.9.1.

The pressurizer surge line has been specifically designed and instrumented to minimize the potential for thermal stratification that could increase cyclic stresses and fatigue usage. At the connection of the surge line to the hot leg, the surge line is sloped 24 degrees from horizontal. The connection to the reactor coolant hot leg is in the portion of the loop piping that is at an angle with horizontal and adjacent to the steam generator inlet nozzle. The run between the hot leg and pressurizer continuously slopes up. The surge line has an angle of at least 2.5 degrees to horizontal. The pressurizer surge line is shown in Figure 5.4-4. Changes of direction in the surge line are made using pipe bends instead of elbow fittings.

The surge line temperature is monitored for indication of thermal stratification. The temperature is monitored at three locations using strap-on resistance temperature detectors. One location is on the vertical section of pipe directly under the pressurizer. The other two locations are on the top and bottom of the pipe at the same diameter on a more horizontal section of pipe near the pressurizer.

Temperatures in the spray lines from the cold legs of one loop are measured and indicated. Alarms from these signals actuate to warn the operator of low spray water temperature or to indicate insufficient flow in the spray lines.

5.4.3.4 Material Corrosion/Erosion Evaluation

The pipe material is selected to minimize corrosion in the reactor coolant water chemistry. (See subsection 5.2.3.) A periodic analysis of the coolant chemistry is performed to verify that the reactor coolant water quality meets the specifications. Water quality is maintained to minimize corrosion by using the chemical and volume control system and sampling system, described in Chapter 9.

Contamination of stainless steel and nickel-chromium-iron alloys by copper, low-melting-temperature alloys, mercury, and lead is prohibited during fabrication, installation, and operation.

The austenitic stainless steel surfaces are cleaned to an appropriate halogen limit. The austenitic stainless steel piping is very resistant to erosion due to single-phase fluid flow. The flow rate in the reactor coolant loop piping and branch connections during normal operation and anticipated transients is significantly below the threshold value for erosion due to water for austenitic stainless steel.

The material selection, water chemistry specification, and residual stress in the piping minimize the potential for stress corrosion cracking. (See subsection 5.2.3.) Reactor coolant system piping is stress-relieved subsequent to bending or other fabrication operations which could result in

significant residual stress in the pipe. Processes such as welding or heat treating which apply heat to stainless steel are controlled to minimize the potential for sensitization of the stainless steel.

Pressure boundary welds out to the second valve that delineates the reactor coolant system boundary are accessible for inservice examination as required by ASME Code, Section XI, and are fitted with removable insulation. Reactor coolant system piping is seamless and does not have any longitudinal welds.

5.4.3.5 Test and Inspections

The reactor coolant system piping construction is subject to a quality assurance program. The pressure boundary components meet requirements established by the ASME Code and ANSI/ASME NQA-1 and NQA-2. The testing included in the reactor coolant system piping quality assurance program is outlined in Table 5.4-8.

A transverse tension test conforming with the supplementary requirements S2 of material specification ASME SA-376 applies to each heat of pipe material.

Ultrasonic examination is performed throughout 100 percent of the wall volume of each pipe, fitting, and other forgings according to the applicable requirements of Section III of the ASME Code for reactor coolant system piping. Unacceptable defects are eliminated according to the requirements of the ASME Code. The surfaces of weld areas are smooth enough to permit preservice and inservice non-destructive examination.

The ends of pipe sections and branch ends are machined to provide a smooth weld transition adjacent to the weld.

A liquid penetrant examination is performed on accessible surfaces, including weld surfaces, of each finished pipe and fitting according to the criteria of the ASME Code, Section III. Acceptance standards are according to the applicable requirements of the ASME Code, Section III. Liquid penetrant examinations are done on the area of pipe bends before the bending operation and after the subsequent heat treatment. Since reactor coolant system piping is austenitic stainless steel, magnetic particle testing for surface examination is not an option. Fillet weld joints are examined by liquid penetrant examination method.

Radiographic examination is performed on circumferential butt welds and on branch connection nozzle welds exceeding 4-inch nominal pipe size.

The examination of a weld repair is repeated as required for the original weld. Except, when the defect was originally detected by the liquid penetrant method, and when the repair cavity does not exceed the lesser of 0.38 inch or 10 percent of the thickness, it need be re-examined only by the liquid penetrant method.

5.4.4 Main Steam Line Flow Restriction

5.4.4.1 Design Bases

The outlet nozzle of the steam generator has a flow restrictor that limits steam flow in the unlikely event of a break in the main steam line. A large increase in steam flow results in choked flow in the restrictor which limits further increase in flow. In a steam line qualified for mechanistic pipe break, a sudden rupture resulting in a large increase in steam flow is not expected. The flow restrictor performs the following functions:

- Limits rapid rise in containment pressure
- Limits the rate of heat removal from the reactor to keep the cooldown rate within acceptable limits
- Reduces thrust forces on the main steam line piping
- Limits pressure differentials on internal steam generator components, particularly the tube support plates

The restrictor is configured to minimize the unrecovered pressure loss across the restrictor during normal operation.

5.4.4.2 Design Description

The flow restrictor consists of seven nickel-chromium-iron Alloy 600 (ASME SB-163) venturi inserts which are installed in holes in an integral steam outlet nozzle forging. The inserts are arranged with one venturi at the centerline of the outlet nozzle, and the other six are equally spaced around it. After insertion into the nozzle forging holes, the venturi inserts are welded to the nickel-chromium-iron alloy cladding on the inner surface of the forging.

5.4.4.3 Design Evaluation

The flow restrictor design has been analyzed to determine its structural adequacy. The equivalent throat area of the steam generator outlet is 1.4 square feet. The resultant pressure drop through the restrictor at 100 percent steam flow is approximately 8.0 psig. This is based on a design flow rate of 7.49×10^6 pounds per hour. Materials of construction of the flow restrictor are in accordance with Code Class 1 Section III of the ASME Code. The material of the inserts is not an ASME Code pressure boundary, nor is it welded to an ASME Code pressure boundary. The method for seismic analysis is dynamic.

5.4.4.4 Inspections

Since the restrictor is not part of the steam system pressure boundary, inservice inspections are not required.

5.4.5 Pressurizer

The pressurizer provides a point in the reactor coolant system where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control of the reactor coolant system during steady-state operations and transients. The pressurizer provides a controlled volume from which level can be measured.

The pressurizer contains the water inventory used to maintain reactor coolant system volume in the event of a minor system leak for a reasonable period without replenishment. The pressurizer surge line connects the pressurizer to one reactor coolant hot leg. This allows continuous coolant volume and pressure adjustments between the reactor coolant system and the pressurizer.

5.4.5.1 Design Bases

The pressurizer is sized to meet following requirements:

- The combined saturated water volume and steam expansion volume is sufficient to provide the desired pressure response to system volume changes.
- The water volume is sufficient to prevent a reactor trip during a step-load increase of 10 percent of full power, with automatic reactor control.
- The water volume is sufficient to prevent uncovering of the heaters following reactor trip and turbine trip, with normal operation of control systems and no failures of nuclear steam supply systems.
- The steam volume is large enough to accommodate the surge resulting from a step load reduction from 100 percent power to house loads without reactor trip, assuming normal operation of control systems.
- The steam volume is large enough to prevent water relief through the safety valves following a complete loss of load with the high water level initiating a reactor trip, without steam dump.
- A low pressurizer pressure engineered safety features actuation signal will not be activated because of a reactor trip and turbine trip, assuming normal operation of control and makeup systems and no failures of the nuclear steam supply systems.

The pressurizer is sized to have sufficient volume to accomplish the preceding requirements without power-operated relief valves. The AP1000 pressurizer has approximately 40 percent more volume than the pressurizers for previous plants with similar power levels. This increased volume provides plant operating flexibility and minimizes challenges to the safety relief valves.

The pressurizer and surge line provide the connection of the reactor coolant system to the safety relief valves and the automatic depressurization system valves. The safety relief valves provide overpressure protection for the reactor coolant system. The automatic depressurization system is provided to reduce reactor coolant system pressure in stages to allow stored water in the

in-containment refueling water storage tank to flow into the reactor coolant system to provide cooling.

The pressurizer surge nozzle and the surge line between the pressurizer and one hot leg are sized to maintain the pressure drop between the reactor coolant system and the safety valves within allowable limits during a design discharge flow from the safety valves or the valves of the automatic depressurization system. Requirements for the surge line and piping connecting the pressurizer to safety and automatic depressurization valves is discussed in subsection 5.4.3.

Section 3.2 discusses the AP1000 equipment classification, seismic category and ASME Code classification of the pressurizer. ASME Code and Code Case compliance is discussed in subsection 5.2.1.

The design stress limits, loads, and combined loading conditions are discussed in subsection 3.9.3. Design transients for the components of the reactor coolant system are discussed in subsection 3.9.1. The pressurizer surge nozzle and surge line are designed to withstand the thermal stresses resulting from volume surges occurring during operation. The evaluation of design transients for the pressurizer addresses the potential for thermal stratification at the surge nozzle.

The pressurizer provides a location for high point venting of noncondensable gases from the reactor coolant system. The gas accumulations in the pressurizer can be removed by remote manual operation of the first-stage automatic depressurization system valves following an accident. Degassing of the pressurizer using the automatic depressurization valves will not be required on a routine basis for normal and moderate frequency events. See subsection 5.4.12 for a discussion of high-point vents.

5.4.5.2 Design Description

5.4.5.2.1 Pressurizer

The pressurizer is a vertical, cylindrical vessel having hemispherical top and bottom heads constructed of low alloy steel. Internal surfaces exposed to the reactor coolant are clad austenitic stainless steel. Material specifications are provided in Table 5.2-1 for the pressurizer.

The general configuration of the pressurizer is shown in Figure 5.4-5. The design data for the pressurizer are given in Table 5.4-9. Codes and material requirements are provided in Section 5.2. Nickel-chromium-iron alloys are not used for heater wells or instrument nozzles.

The spray line nozzles and the automatic depressurization and safety valve connections are located in the top head of the pressurizer vessel. Spray flow is modulated by automatically controlled air-operated valves. The spray valves can also be operated manually from the control room. In the bottom head at the connection of the surge line to the surge nozzle a thermal sleeve protects the nozzle from thermal transients.

A retaining screen above the surge nozzle prevents passage of any foreign matter from the pressurizer to the reactor coolant system. Baffles in the lower section of the pressurizer prevent an in-surge of cold water from flowing directly to the steam/water interface. The baffles also assist in

mixing the incoming water with the water in the pressurizer. The retaining screen and baffles also act as a diffuser. The baffles also support the heaters to limit vibration.

Electric direct-immersion heaters are installed in vertically oriented heater wells located in the pressurizer bottom head. The heater wells are welded to the bottom head and form part of the pressure boundary. The heaters can be removed for maintenance or replacement.

The heaters are grouped into a control group and backup groups. The heaters in the control group are proportional heaters which are supplied with continuously variable power to match heating needs. The heaters in the backup group are either off or at full power. The power supply to the heaters is a 480-volt 60 Hz. three-phase circuit. Each heater is connected to one leg of a delta-connected circuit and is rated at 480 volts with one-phase current. The capacity of the control and backup groups is defined in Table 5.4-10.

A manway in the upper head provides access to the internal space of the pressurizer in order to inspect or maintain the spray nozzle. The manway closure is a gasketed cover held in place with threaded fasteners. Periodic planned inspections of the pressurizer interior are not required.

Brackets on the upper shell attach the structure (a ring girder) of the pressurizer safety and relief valve (PSARV) module. The pressurizer safety and relief valve module includes the safety valves and the first three stages of automatic depressurization system valves. The support brackets on the pressurizer represent the primary vertical load path to the building structure. Sway struts between the ring girder and pressurizer compartment walls also provide lateral support to the upper portion of the pressurizer. See subsection 5.4.10 for additional details.

Four steel columns attach to pads on the lower head to provide vertical support for the vessel. The columns are based at elevation 107'-2". Lateral support for the lower portion of the vessel is provided by sway struts between the columns and compartment walls.

5.4.5.2.2 Instrumentation

Instrument connections are provided in the pressurizer shell to measure important parameters. Eight level taps are provided for four channels of level measurement. Level taps are also used for connection to the pressure measurement instrumentation. Two temperature taps monitor water/steam temperature. A sample tap connection is provided for connection to the sampling system to monitor coolant chemistry. The instrument and sample taps are constructed of stainless steel and designed for a socket weld of the connecting lines to the taps. The sample and instrument taps incorporate an integral flow restrictor with a diameter of 0.38 inch or smaller.

See Chapter 7 for details of the instrumentation associated with pressurizer pressure, level, and temperature.

5.4.5.2.3 Operation

During steady-state operation at 100 percent power, approximately 50 percent of the pressurizer volume is water and 50 percent is steam. Electric immersion heaters in the bottom of the vessel keep the water at saturation temperature. The heaters also maintain a constant operating pressure.

A small continuous spray flow is provided through a manual bypass valve around each power-operated spray valve to minimize the boron concentration difference between the pressurizer liquid and the reactor coolant. This continuous flow also prevents excessive cooling of the spray piping. Proportional heaters in the control group are continuously on during normal operation to compensate for the continuous introduction of cooler spray water and for losses to ambient.

These conditions result in a continuous out-surge in most cases during normal operation and anticipated transients. The out-surge minimizes the potential for thermal stratification in the surge line.

During an out-surge of water from the pressurizer, flashing of water to steam and generation of steam by automatic actuation of the heaters keep the pressure above the low-pressure engineered safety features actuation setpoint. During an in-surge from the reactor coolant system, the spray system (which is fed from two cold legs) condenses steam in the pressurizer. This prevents the pressurizer pressure from reaching the high-pressure reactor trip setpoint. The heaters are energized on high water level during in-surge to heat the subcooled surge water entering the pressurizer from the reactor coolant loop.

During heatup and cooldown of the plant, when the potential for thermal stratification in the pressurizer is the greatest, the pressurizer may be operated with a continuous outsurge of water from the pressurizer. This is achieved by continuous maximum spray flow and energizing of all of the backup pressurizer heater groups. The temperature difference between the pressurizer and hot leg is minimized by maintaining the lowest reactor coolant system pressure possible consistent with operation of a canned motor reactor coolant pump. This mode of operation minimizes the frequency and magnitude of thermal shock to the surge line nozzle and lower pressurizer head, and the potential for stratification in the pressurizer and surge line. The design analyses of the pressurizer include consideration of transients on the lower head and shell regions to account for these possible insurge/outsurge events.

The pressurizer is the initial source of water to keep the reactor coolant system full of water in the event of a small loss of coolant. Pressurizer level and pressure measurements indicate if other sources of water, including the chemical volume and control system and passive safety systems, must be used to supply additional reactor coolant.

Power to the pressurizer heaters is blocked when the core makeup tanks are actuated. This action reduces the potential for steam generator overfill for a steam generator tube rupture accident.

5.4.5.3 Design Evaluation

5.4.5.3.1 System Pressure Control

The reactor coolant system pressure is controlled by the pressurizer whenever a steam volume is present in the pressurizer.

A design basis safety limit has been set so that the reactor coolant system pressure does not exceed the maximum transient value based on the design pressure as allowed under the ASME Code, Section III. Evaluation of plant conditions of operation considered for design indicates that this

safety limit is not reached. The safety valves provide overpressure protection. See subsection 5.2.2.

During startup and shutdown, the rate of temperature change in the reactor coolant system is controlled automatically by the steam dump system. Heatup rate is controlled by energy input from the reactor coolant pumps and by the modulation of the steam dump valves. Pressurizer heatup rate is controlled by the electrical heaters in the pressurizer.

When the pressurizer is filled with water, i.e., during initial system heatup or near the end of the second phase of plant cooldown, reactor coolant system pressure is controlled by the letdown flowrate.

The AP1000 pressurizer heaters are powered from the 480 V ac system. During loss of offsite power events concurrent with a turbine trip, selected pressurizer heater buses are capable of being powered from the onsite diesel generators via manual alignment. This permits use of the pressurizer for control purposes when power is supplied by the diesel-generators. The power supplied by the diesel-generators is sufficient to establish and maintain natural circulation in hot standby condition in conformance with the requirement of 10 CFR 50.34 (f)(2)(xiii).

If loss of offsite power occurs and onsite power is available, the pressurizer heaters and startup feedwater pumps can operate to provide natural circulation and cooling through the steam generators.

Should the onsite diesel generators not be available during loss of offsite power events, core decay heat is removed from the reactor coolant system using the passive residual heat removal heat exchanger. The decay heat is transferred to the in-containment refueling water storage tank (IRWST) water. The passive core cooling system does not require the use of pressurizer heaters to maintain pressure control. The passive containment cooling system functions to maintain the plant in a safe condition.

NUREG-0737, Action Item II.E.3.1, outlines four requirements for emergency power supply to the pressurizer heaters for purposes of establishing natural circulation in the reactor coolant system during a loss of offsite power. NUREG-0737 does not address scenarios involving natural circulation cooling for a loss of all ac power, which is a design basis for the AP1000. Under these circumstances, cooling is provided by the passive residual heat removal system. Upon a loss of all ac power, the heaters are not available to maintain the pressurizer inventory in a saturated condition. That condition is not needed for the plant to be maintained in a safe condition. On this basis, compliance with the requirements of the action item is not required to provide for the safety of the AP1000. Nevertheless, AP1000 compliance with the intent of these requirements is summarized in the following paragraphs.

The heaters are powered from separate electrical buses for each heater group. Two groups of heaters can be administratively loaded onto the non-Class 1E diesel-generator-backed buses (Figure 8.3.1-1).

Analysis of AP1000 steady-state heat losses indicates that a heater capacity of about 166 kW is sufficient to provide saturated conditions in the pressurizer. Each AP1000 heater group has a

capacity greater than 166 kW (see Table 5.4-10). One group alone can maintain control over reactor coolant system pressure and subcooling.

Established administrative procedures are followed for re-energizing groups. Associated actions can be controlled from either the main control room or the shutdown panel. It is not necessary to shed other loads in order to manually load a heater group.

Based on analysis of other pressurizer water reactors, the reactor coolant system sensible heat capacity is such that adequate subcooling can be maintained in the reactor coolant system for four hours without heat input from the pressurizer heaters. Thus, the time required to accomplish connection of the heaters to the emergency buses is consistent with timely initiation of natural circulation conditions.

Since the buses supplying the heaters for the diesel generators are not Class 1E, the 480 V breakers supplying the heaters are not required to be "qualified in accordance with safety-related requirements."

5.4.5.3.2 Pressurizer Level Control

The normal operating water volume at full-load conditions is approximately 50 percent of the free internal vessel volume. Under part-load conditions the water volume in the pressurizer is reduced proportionally with reductions in plant load to approximately 25 percent of the free internal vessel volume at the zero-power condition.

5.4.5.3.3 Pressure Setpoints

The reactor coolant system design and operating pressure, together with the safety valve setpoints, heater actuation setpoints, pressurizer spray valve setpoints, and protection system pressure setpoints, are listed in Table 5.4-11. When operating in load regulation mode, the pressurizer spray and backup heaters are on continuously. This continuous operation decreases the number of actuations of the backup heaters and spray valves, thereby extending the component lifetimes.

The selected design margin considers core thermal lag, coolant transport times and pressure drops, instrumentation and control response characteristics, and system relief valve characteristics. The design pressure allows for operating transient pressure changes.

The low pressurizer pressure engineered safety features actuation signal does not require a coincident low pressurizer water level signal.

5.4.5.3.4 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. The throttle permits a small, continuous flow through both spray lines to reduce thermal stresses and thermal shock when the spray valves open. Flow through this valve helps to maintain uniform water chemistry and

temperature in the pressurizer. Temperature sensors with low temperature alarms are located 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 that prevents steam buildup back to the control valves. The design spray rate is selected to prevent the pressurizer pressure from reaching the reactor trip setpoint during a step reduction in power level of 10 percent of full load.

The pressurizer spray lines and valves are large enough to provide the required spray flowrate under the driving force of 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 use the velocity head of the reactor coolant loop flow to add to the spray driving force. The spray line also assists in equalizing the boron concentration between the reactor coolant loops and the pressurizer.

A flowpath from the chemical and volume control system to the pressurizer spray line is also provided. This path provides auxiliary spray to the vapor space of the pressurizer during cooldown, hot standby, and hot shutdown when the reactor coolant pumps are not operating. The pressurizer spray connection and the spray piping can withstand the thermal stresses resulting from the introduction of cold spray water.

5.4.5.4 Tests and Inspections

The pressurizer construction is subject to a quality assurance program. The pressure boundary components meet requirements established by the ASME Code and ANSI/ASME NQA-1 and NQA-2. Table 5.4-12 outlines the testing included in the pressurizer quality assurance program.

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

- Surge nozzle to the lower head
- Safety and spray nozzles to the upper head
- Nozzle to safe end attachment welds
- The girth full-penetration welds

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.

5.4.6 Automatic Depressurization System Valves

The automatic depressurization system (ADS) valves are part of the reactor coolant system and interface with the passive core cooling system (PXS). Twenty valves are divided into four depressurization stages. These stages connect to the reactor coolant system at three different locations. The automatic depressurization system first, second, and third stage valves are included

as part of the pressurizer safety and relief valve (PSARV) module and are connected to nozzles on top of the pressurizer. The fourth stage valves connect to the hot leg of each reactor coolant loop. The reactor coolant system P&ID, Figure 5.1-5, shows the arrangement of the valves.

Opening of the automatic depressurization system valves is required for the passive core cooling system to function as required to provide emergency core cooling following postulated accident conditions. Operation of the passive core cooling system, including setpoints for the opening of the automatic depressurization system valves is discussed in Section 6.3.

The first stage valves may also be used, as required following an accident, to remove noncondensable gases from the steam space of the pressurizer. (See subsection 5.4.11.)

5.4.6.1 Design Bases

Subsection 5.4.8 discusses the general design basis, design evaluation, and testing and inspection for reactor coolant system valves, including the automatic depressurization system valves. The automatic depressurization system valves are seismic Category 1, AP1000 equipment Class A components. (See subsection 3.2.2.) The fourth stage valves are interlocked so that they can not be opened until reactor coolant system pressure has been substantially reduced. The design criteria and bases, functional requirements, mechanical design, and testing and inspection of the passive core cooling system are included in Section 6.3. The design requirements for the passive core cooling system also apply to automatic depressurization valves except where the requirements for reactor coolant system valves are more restrictive.

5.4.6.2 Design Description

The first stage automatic depressurization system valves are motor-operated 4-inch valves. The second and third stage automatic depressurization system valves are motor-operated 8-inch valves. The fourth stage automatic depressurization system valves are 14 inch squib valves arranged in series with normally-open, dc powered, motor-operator valves. See Section 6.3 for a discussion of the sizing of the automatic depressurization system valves.

The control system for the opening of the automatic depressurization system valves, as part of the passive core cooling system, has an appropriate level of diverse and redundant features to minimize the inadvertent opening of the valves.

For each discharge path a pair of valves are placed in series to minimize the potential for an inadvertent discharge of the automatic depressurization system valves. The fourth stage valves are interlocked so that they cannot be opened until reactor coolant system pressure has been substantially reduced.

The first, second, and third stage valves are located on the pressurizer safety and relief valve module clustered into two groups. Each group has one pair of valves for each stage. The two groups are on different elevations and are separated by a steel plate.

Vacuum breakers are provided in the AP1000 ADS discharge lines to help prevent water hammer following ADS operation. The vacuum breakers limit the pressure reduction that could be caused

by steam condensation in the discharge line and thus limit the potential for liquid backflow from the in-containment refueling water storage tank following ADS operation.

A bypass test line is connected to the inlet and outlet of the first, second, and third stage upstream isolation valves. This bypass line can control the differential pressure across the upstream valves during inservice testing. The bypass test solenoid valves do not have a safety-related function to open.

5.4.6.3 Design Verification

The automatic depressurization system valves are verified to meet their safety-related functional requirements by the following:

- Valve equipment qualification
- Pre-operational valve operational verification
- In-service valve operational verification

Automatic depressurization system valve qualification is addressed in subsection 5.4.8.1.2 for the stage 1/2/3 motor operated valves and in subsection 5.4.8.1.3 for the stage 4 squib valves. The equipment qualification includes type testing which verifies the automatic depressurization system valve operability and flow capacity. Automatic depressurization system valve pre-operational valve operational verification is addressed in subsection 14.2.9.1. Automatic depressurization system valve in-service valve operational verification is addressed in subsection 3.9.6.2.2 and Table 3.9-16.

5.4.6.4 Inspection and Testing Requirements

The requirements for tests and inspections for reactor coolant system valves is found in subsection 5.4.8.4. In addition, tests for the automatic depressurization system valves and piping are conducted during preoperational testing of the passive core cooling system, as discussed in Sections 6.3 and 14.2.

5.4.6.4.1 Flow Testing

Initial verification of the resistance of the automatic depressurization system piping and valves is performed during the plant initial test program. A low pressure flow test and associated analysis is conducted to determine the total piping flow resistance of each automatic depressurization system valve group connected to the pressurizer (i.e. stages 1-3) from the pressurizer through the outlet of the downstream valve. The reactor coolant system shall be at cold conditions with the pressurizer full of water. The normal residual heat removal pumps will be used to provide injection flow into the reactor coolant system, discharging through the ADS valves.

Inspections and associated analysis of the piping flow paths from the discharge of the automatic depressurization system valve groups connected to the pressurizer (i.e., stages 1-3) to the spargers are conducted to verify the line routings are consistent with the line routings used for design flow resistance calculations. The calculated piping flow resistances from the pressurizer through the sparger, with valves of each group open are bounded by the resistances used in the Chapter 15 safety analysis.

Inspection of the piping flow paths from each hot leg through the automatic depressurization stage 4 valves is conducted. The calculated flow resistances with valves in each group open are bounded by the resistances used in the Chapter 15 safety analysis.

5.4.7 Normal Residual Heat Removal System

The normal residual heat removal system (RNS) performs the following major functions:

- **Reactor Coolant System Shutdown Heat Removal -** Remove heat from the core and the reactor coolant system during shutdown operations.

- **Shutdown Purification -** Provide reactor coolant system and refueling cavity purification flow to the chemical and volume control system during refueling operations.

- **In-containment Refueling Water Storage Tank Cooling -** Provide cooling for the in-containment refueling water storage tank.

- **Reactor Coolant System Makeup -** Provide low pressure makeup to the reactor coolant system.

- **Post-Accident Recovery -** Remove heat from the core and the reactor coolant system following successful mitigation of an accident by the passive core cooling system.

- **Low Temperature Overpressure Protection -** Provide low temperature overpressure protection (LTOP) for the reactor coolant system during refueling, startup, and shutdown operations.

- **Long-Term, Post-Accident Containment Inventory Makeup Flowpath -** Provide long-term, post-accident makeup flowpath to the containment inventory.

- **Spent Fuel Pool Cooling -** Provide backup for cooling the spent fuel pool.

5.4.7.1 Design Bases

5.4.7.1.1 Safety Design Bases

The safety-related functions provided by the normal residual heat removal system include containment isolation of normal residual heat removal system lines penetrating containment, preservation of the reactor coolant system pressure boundary and a flow path for long term post-accident makeup to the containment inventory. The containment isolation valves perform the containment isolation function according to the criteria specified in subsection 6.2.3. The system preserves the reactor coolant system pressure boundary according to the criteria specified in subsection 5.4.8.

The normal residual heat removal system piping and components outside containment are an AP1000 Class C, Seismic Category I pressure boundary. This classification recognizes the importance of pressure boundary integrity even though these components have no safety-related functions.

5.4.7.1.2 Nonsafety Design Bases

Subsection 5.4.7 outlines the principal functions of the normal residual heat removal system. The normal residual heat removal system is designed to be reliable. This reliability is achieved by using redundant equipment and a simplified system design. The normal residual heat removal system is not a safety-related system. It is not required to operate to mitigate design basis events.

The normal residual heat removal system is designed for a single nuclear power unit and is not shared between units. The normal residual heat removal system is operated from the main control room.

The normal residual heat removal system provides the capability to cool the spent fuel pool during times when it is not needed for removing heat from the reactor coolant system.

5.4.7.1.2.1 Shutdown Heat Removal

The normal residual heat removal system removes both residual and sensible heat from the core and the reactor coolant system. It reduces the temperature of the reactor coolant system during the second phase of plant cooldown. The first phase of cooldown is accomplished by transferring heat from the reactor coolant system via the steam generators to the main steam system (MSS).

Following cooldown, the normal residual heat removal system removes heat from the core and the reactor coolant system during the plant shutdown, until the plant is started up.

The normal residual heat removal system reduces the temperature of the reactor coolant system from 350° to 125°F within 96 hours after shutdown. The system maintains the reactor coolant temperature at or below 125°F for the plant shutdown. The system performs this function based on the following:

- Operation of the system with both subsystems of normal residual heat removal system pumps and heat exchangers available.

- Initiation of normal residual heat removal system operation at four hours following reactor shutdown, after the first phase of cooldown by the main steam system has reduced the reactor coolant system temperature to less than or equal to 350°F and 450 psig.

- The component cooling water system supply temperature to the normal residual heat removal system heat exchangers is based on an ambient wet bulb temperature of no greater than 80°F (1 percent exceedance). The 80°F value is assumed for shutdown cooling.

- Operation of the system is consistent with reactor coolant system cooldown rate limits and consistent with maintaining the component cooling water below design limits during cooldown.

- Core decay heat generation is based on the decay heat curve for a three-region core having burnups consistent with a 24-month or 18-month refueling schedule and based on the ANSI/ANS-5.1-1994 decay heat curve (Reference 5).

- A failure of an active component during normal cooldown does not preclude the ability to cool down, but lengthens the time required to reach 125°F. Furthermore, if such a single failure occurs while the reactor vessel head is removed, the reactor coolant temperature remains below boiling temperature.

- The system operates at a constant normal residual heat removal flow rate throughout refueling operations. This includes the time when the level in the reactor coolant system is reduced to a midloop level to facilitate draining of the steam generators or removal of a reactor coolant pump. Operation of the system at the minimum level that the reactor coolant system can attain using the normal reactor coolant system draining connections and procedures results in no incipient vortex formation which would cause air entrainment into the pump suction.

- The pump suction line is self-venting with continually upward sloped pipe from the pump suction to the hot leg. This arrangement prevents entrapment of air and minimizes system venting efforts for startup.

- Features are included that permit mid-loop operations to be performed from the main control room.

5.4.7.1.2.2 Shutdown Purification

The normal residual heat removal system provides reactor coolant system flow to the chemical and volume control system during refueling operations. The purification flow rate is consistent with the purification flow rate specified in Table 9.3.6-1.

5.4.7.1.2.3 In-Containment Refueling Water Storage Tank Cooling

The normal residual heat removal system provides cooling for the in-containment refueling water storage tank during operation of the passive residual heat removal heat exchanger or during normal plant operations when required. The system is manually initiated by the operator. The normal residual heat removal system limits the in-containment refueling water storage tank water temperature to less than boiling temperature during extended operation of the passive residual heat removal system and to not greater than 120°F during normal operation. The system performs this function based on the following:

- Operation of the system with both subsystems of normal residual heat removal system pumps and heat exchangers available.

- The component cooling water system supply temperature to the normal residual heat removal system heat exchangers is based on an ambient design wet bulb temperature of no greater than 81°F (0 percent exceedance). The 81°F value is assumed for normal conditions and transients that start at normal conditions.

Since the normal residual heat removal system is not a safety-related system, its operation is not credited in Chapter 15 Accident Analyses.

5.4.7.1.2.4 Low Pressure Reactor Coolant System Makeup and Cooling

The normal residual heat removal system provides low pressure makeup from the cask loading pit to the reactor coolant system. The system is manually initiated by the operator following receipt of an automatic depressurization signal. If the system is available, it provides reactor coolant system makeup once the pressure in the reactor coolant system falls below the shutoff head of the normal residual heat removal system pumps. The system provides makeup from the cask loading pit to the reactor coolant system and provides additional margin for core cooling. The normal residual heat removal system is not required to mitigate design basis accidents, and therefore its operation is not considered in Chapter 15 Accident Analyses.

5.4.7.1.2.5 Low Temperature Overpressure Protection

The normal residual heat removal system provides a low temperature overpressure protection function for the reactor coolant system during refueling, startup, and shutdown operations. The system is designed to limit the reactor coolant system pressure to the lower of either the limits specified in 10 CFR 50, Appendix G, or 110 percent of the normal residual heat removal system design pressure.

5.4.7.1.2.6 Spent Fuel Pool Cooling

The normal residual heat removal system has the capability to supplement or take over the cooling of the spent fuel pool when it is not needed for normal shutdown cooling.

5.4.7.2 System Description

Figure 5.4-6 shows a simplified sketch of the normal residual heat removal system. Figure 5.4-7 shows the piping and instrumentation diagram for the normal residual heat removal system. Table 5.4-13 gives the important system design parameters.

The inside containment portions of the system from the reactor coolant system up to and including the containment isolation valves outside containment are designed for full reactor coolant system pressure. The portion of the system outside containment, including the pumps, valves and heat exchangers, has a design pressure and temperature such that full reactor coolant system pressure is below the ultimate rupture strength of the piping.

The normal residual heat removal system consists of two mechanical trains of equipment. Each train includes one residual heat removal pump and one residual heat removal heat exchanger. The two trains of equipment share a common suction line from the reactor coolant system and a common discharge header. The normal residual heat removal system includes the piping, valves and instrumentation necessary for system operation.

The normal residual heat removal system suction header is connected to a reactor coolant system hot leg with a single step-nozzle connection. The step-nozzle connection is employed to minimize the likelihood of air ingestion into the residual heat removal pumps during reactor coolant system mid-loop operations. The suction header then splits into lines with two parallel sets of two normally closed, motor-operated isolation valves in series. This arrangement allows for normal residual heat removal system operation following a single failure of an isolation valve to

open and also allows for normal residual heat removal system isolation following a single failure of an isolation valve to close.

The lines join into a common suction line inside containment. A single line from the inside-containment refueling water storage tank is connected to the suction header before it leaves containment.

Once outside containment, the suction header contains a single normally closed, motor-operated isolation valve. Downstream of the suction header isolation valve, the header branches into two separate lines, one to each pump. Each branch line has a normally open, manual isolation valve upstream of the residual heat removal pumps. These valves are provided for pump maintenance.

The normal residual heat removal system suction header is continuously sloped from the reactor coolant system hot leg to the pump suction. This eliminates any local high points where air could collect and cause low net positive suction head, pump binding and a loss of residual heat removal capability.

The discharge of each residual heat removal pump is directed to its respective residual heat removal heat exchanger. The outlet of each residual heat removal heat exchanger is routed to the common discharge header, which contains a normally closed, motor-operated isolation valve. For pump protection, a miniflow line with an orifice is included from downstream of the residual heat removal heat exchanger to upstream of the residual heat removal pump suction. This line is sized to provide sufficient pump flow when the pressure in the reactor coolant system is above the residual heat removal pump shutoff head.

Once inside containment, the common discharge header contains a check valve that acts as a containment isolation valve. Downstream of the check valve, the discharge header branches into two lines, one to each passive core cooling system direct vessel injection nozzle. These branch lines each contain a stop check valve and check valve in series that serve as the reactor coolant system pressure boundary. A line to the chemical and volume control system demineralizers branches from one of the direct vessel injection lines. This line is used for shutdown purification of the reactor coolant system. Another line branches from the same direct vessel injection line to the in-containment refueling water storage tank which is used when cooling the tank.

One safety relief valve is located on the normal residual heat removal system suction header inside containment. This valve provides low temperature overpressure protection of the reactor coolant system. Subsection 5.4.9 describes the sizing basis of this valve. Another safety relief valve outside of containment provides protection against excess pressure for the piping and components.

When the normal residual heat removal system is in operation, the water chemistry is the same as that of the reactor coolant. Sampling may be performed using the normal residual heat removal heat exchangers channel head drain connections. Sampling of the reactor coolant system using these connections is available at shutdown. Sampling of the in-containment refueling water storage tank is available during normal plant operation.

5.4.7.2.1 Design Features Addressing Shutdown and Mid-Loop Operations

The following is a summary of the specific AP1000 design features that address Generic Letter (GL) 88-17 regarding mid-loop operations. In addition, these features support improved safety during shutdown.

Loop Piping Offset - As shown in Figure 5.3-6, the reactor coolant system hot legs and cold legs are vertically offset. This permits draining of the steam generators for nozzle dam insertion with hot leg level much higher than traditional designs. The reactor coolant system must be drained to a level which is sufficient to provide a vent path from the pressurizer to the steam generators. This is nominally 80 percent level in the hot leg. This loop piping offset also allows a reactor coolant pump to be replaced without removing a full core.

Step-nozzle Connection - The normal residual heat removal system employs a step-nozzle connection to the reactor coolant system hot leg. The step-nozzle connection has two effects on mid-loop operation. One effect is to substantially lower the RCS hot leg level at which a vortex occurs in the residual heat removal pump suction line due to the lower fluid velocity in the hot leg nozzle. This increases the margin from the nominal mid-loop level to the level where air entrainment into the pump suction begins.

Another effect of the step-nozzle is that, if a vortex should occur, the maximum air entrainment into the pump suction has been shown experimentally to be no greater than 5 percent. This level of air ingestion will make air binding of the pump much less likely.

Normal Residual Heat Removal Throttling During Mid-Loop - The normal residual heat removal pumps are designed to minimize susceptibility to cavitation. Normally, the normal residual heat removal system operates without the need for throttling a residual heat removal control valve when the level in the reactor coolant system is reduced to a mid-loop level. If the reactor coolant system is at saturated conditions and mid-loop level, some throttling of a flow control valve is necessary to maintain adequate net positive suction head.

Self-Venting Suction Line - The residual heat removal pump suction line is sloped continuously upward from the pump to the reactor coolant system hot leg with no local high points. This eliminates potential problems with refilling the pump suction line if a residual heat removal pump is stopped when cavitating due to excessive air entrainment. With the self-venting suction line, the line will refill and the pumps can be immediately restarted once an adequate level in the hot leg is re-established.

Wide Range Pressurizer Level - A nonsafety-related independent pressurizer level transmitter, calibrated for low temperature conditions, provides water level indication during startup, shutdown, and refueling operations in the main control room and at the remote shutdown workstation. The upper level tap is connected to an ADS valve inlet header above the top of the pressurizer. The lower level tap is connected to the bottom of the hot leg. This provides level indication for the entire pressurizer and a continuous reading as the level in the pressurizer decreases to mid-loop levels during shutdown operations.

Hot Leg Level Instrumentation - The AP1000 reactor coolant system contains level instrumentation in each hot leg with indication in the main control room. In addition to the wide-range pressurizer level instrumentation (used during cold plant operation) which provides continuous level indication in the main control room from the normal level in the pressurizer, two narrow-range hot leg level instruments are available. Alarms are provided to alert the operator when the reactor coolant system hot leg level is approaching a low level. The isolation valves in the line used to drain the reactor coolant system close on a low reactor coolant system level during shutdown operations. Operations required during mid-loop are performed by the operator in the main control room. The level monitoring and control features significantly improve the reliability of the AP1000 during mid-loop operations.

Reactor Vessel Outlet Temperature - Reactor coolant system hot leg wide range temperature instruments are provided in each hot leg. The orientation of the wide range thermowell-mounted resistance temperature detectors enables measurement of the reactor coolant fluid in the hot leg when in reduced inventory conditions. In addition, at least two incore thermocouple channels are available to measure the core exit temperature during midloop residual heat removal operation. These two thermocouple channels are associated with separate electrical divisions.

ADS Valves - The automatic depressurization system first-, second-, and third-stage valves, connected to the top of the pressurizer, are open whenever the core makeup tanks are blocked during shutdown conditions while the reactor vessel upper internals are in place. This provides a vent path to preclude pressurization of the reactor coolant system during shutdown conditions when decay heat removal is lost. This also allows the in-containment refueling water storage tank to automatically provide injection flow if it is actuated on a loss of decay heat removal.

The capability to restore containment integrity during shutdown conditions is provided. The containment equipment hatches are equipped with guide rails that allow reinstallation of the hatches to re-establish containment integrity. The containment design also includes penetrations for temporary cables and hoses needed for shutdown operations.

Procedures direct the operator in the proper conduct of midloop operation and aid in identifying and correcting abnormal conditions that might occur during shutdown operations.

5.4.7.2.2 Design Features Addressing Intersystem LOCA

The AP1000 has addressed the intersystem LOCA section of SECY 90-016 with a number of design features. These design features are:

Codes and Standards/Seismic Protection - The portions of the normal residual heat removal system located outside containment (that serve no active safety functions) are classified as AP1000 Equipment Class C so that the design, manufacture, installation, and inspection of this pressure boundary is in accordance with the following industry codes and standards and regulatory requirements: 10 CFR 50, Appendix B; Regulatory Guide 1.26 Quality Group C; and ASME Boiler and Pressure Vessel Code, Section III, Class 3. The pressure boundary is classified as Seismic Category I.

Increased Design Pressure - The portions of the normal residual heat removal system from the reactor coolant system to the containment isolation valves outside containment are designed to the operating pressure of the reactor coolant system. The portions of the system downstream of the suction line containment isolation valve and upstream of the discharge line containment isolation valve are designed so that its ultimate rupture strength is not less than the operating pressure of the reactor coolant system. Specifically, the piping is designed as schedule 80S, and the flanges, valves, and fittings are specified to be greater than or equal to ANS class 900. The design pressure of the normal residual heat removal system is 900 psi, which is approximately 40 percent of operating reactor coolant system pressure.

Reactor Coolant System Isolation Valve - The AP1000 normal residual heat removal system contains an isolation valve in the pump suction line from the reactor coolant system. This motor-operated containment isolation valve is designed to the reactor coolant system pressure. It provides an additional barrier between the reactor coolant system and lower pressure portions of the normal residual heat removal system.

Normal Residual Heat Removal System Relief Valve - The inside containment AP1000 normal residual heat removal system relief valve is connected to the residual heat removal pump suction line. This valve is designed to provide low-temperature overpressure protection of the reactor coolant system as described in subsection 5.2.2. It is connected to the high pressure portion of the pump suction line and reduces the risk of overpressurizing the low pressure portions of the system.

Features Preventing Inadvertent Opening of Isolation Valves - The reactor coolant system isolation valves are interlocked to prevent their opening at reactor coolant system pressures above 450 psig. Section 7.6 discusses this interlock. The power to these valves is administratively blocked during normal power operation.

RCS Pressure Indication and High Alarm - The AP1000 Normal residual heat removal system contains an instrumentation channel that indicates pressure in each normal residual heat removal pump suction line. A high pressure alarm is provided in the main control room to alert the operator to a condition of rising RCS pressure that could eventually exceed the design pressure of the normal residual heat removal system.

Closed valves connecting to spent fuel pool - The cross-connecting piping between the normal residual heat removal system and the spent fuel pool cooling system is isolated by normally closed valves.

5.4.7.3 Component Description

The descriptions of the normal residual heat removal system components are provided in the following subsections. Table 5.4-14 lists the key equipment parameters for the normal residual heat removal system components.

5.4.7.3.1 Normal Residual Heat Removal Pumps (MP01 A&B)

Two residual heat removal pumps are provided. These pumps are single stage, vertical in-line, bottom suction centrifugal pumps. They are coupled with a motor shaft driven by an ac powered induction motor.

Each pump is sized to provide the flow required by its respective heat exchanger for removal of its design basis heat load. Redundant pumps and heat exchangers provide sufficient cooling to prevent RCS boiling if one subsystem is inoperative. A continuously open miniflow line is also provided to protect the pump from operation at low flow conditions.

5.4.7.3.2 Normal Residual Heat Removal Heat Exchangers (ME01 A&B)

Two residual heat removal heat exchangers are installed to provide redundant residual heat removal capability. These heat exchangers are vertically mounted, shell and U-tube design. Reactor coolant flow circulates through the stainless steel tubes while component cooling water circulates through the carbon steel shell. The tubes are welded to the tubesheet.

5.4.7.3.3 Normal Residual Heat Removal Valves

The normal residual heat removal system packed valves designated for radioactive service are provided with stem packing designs that provide enhanced resistance to leakage. Leakage to the atmosphere is essentially zero for these valves.

Manual and motor-operated valves have backseats to facilitate repacking and to limit stem leakage when the valves are open. The basic material of construction for valves is stainless steel.

5.4.7.3.3.1 Reactor Coolant System Inner/Outer Isolation Valves (V001 A&B, V002 A&B)

There are two parallel sets of two valves in series for a total of four valves. These valves are normally closed, motor-operated valves and are located inside the containment. These valves form the reactor coolant pressure boundary. They are opened only for normal cooldown after reactor coolant system depressurization to 450 psig. They are controlled from the main control room and fail in the “as-is” position. These valves are protected from inadvertently opening when the reactor coolant system pressure is above 450 psig by an interlock. Power to these valves is administratively blocked during normal power operations.

5.4.7.3.3.2 In-Containment Refueling Water Storage Tank Suction Line Isolation Valve (V023)

There is one motor-operated valve located inside containment in the line from the in-containment refueling water storage tank to the pump suction header. This valve is designed for full reactor coolant system pressure. It also acts as a containment isolation valve.

5.4.7.3.3.3 Residual Heat Removal Isolation Valve (V011)

There is one motor-operated valve in the pump discharge header outside of containment. This valve is designed for full reactor coolant system pressure. It also acts as a containment isolation valve.

5.4.7.3.3.4 In-Containment Refueling Water Storage Tank Return Isolation Valve (V024)

There is one normally closed motor-operated valve located inside containment in the discharge line to the in-containment refueling water storage tank. This valve is aligned for full-flow testing of the residual heat removal pumps or for operations involving cooling of the in-containment refueling water storage tank.

5.4.7.3.3.5 Cask Loading Pit Isolation Valve (V055)

There is one normally closed motor-operated valve in the line between the cask loading pit and the residual heat removal pump suction line. This valve can be opened by the operator to provide low pressure injection from the cask loading pit to the reactor coolant system during an accident.

5.4.7.3.3.6 Normal Residual Heat Removal Pump Miniflow Isolation Valves (V057A & B)

There is one normally open air-operated valve in each of the residual heat removal pump miniflow lines. During plant cooldown the operator can close these valves to increase the circulating flow rate of the reactor coolant through the residual heat removal heat exchangers to decrease the reactor coolant system cooldown time. These valves automatically open on low flow in the residual heat removal heat exchanger discharge line.

5.4.7.4 System Operation and Performance

Operation of the normal residual heat removal system is described in the following sections. System operations are controlled and monitored from the main control room, including mid-loop operations. The reactor coolant system is equipped with mid-loop level instrumentation with remote readout in the main control room. This instrumentation is used for monitoring mid-loop operations from the main control room.

5.4.7.4.1 Plant Startup

Plant startup includes the operations that bring the reactor plant from a cold shutdown condition to no-load operating temperature and pressure, and subsequently to power operation.

During cold shutdown conditions, both residual heat removal pumps and heat exchangers operate to circulate reactor coolant and remove decay heat. The residual heat removal pumps are switched off when plant startup begins. The normal residual heat removal system remains aligned to the reactor coolant system to maintain a low pressure letdown path to the chemical and volume control system. This alignment provides reactor coolant system purification flow and low temperature over-pressure protection of the reactor coolant system. As the reactor coolant pumps are started, their thermal input begins heating the reactor coolant inventory. Once the pressurizer steam bubble formation is complete, the normal residual heat removal system suction header isolation valve and the discharge header isolation valve are closed and tested for leakage. The valve arrangement is then set for normal operation, as shown in Figure 5.4-6.

5.4.7.4.2 Plant Cooldown

Plant cooldown is the operation that brings the reactor plant from normal operating temperature and pressure to refueling conditions.

The initial phase of plant cooldown consists of reactor coolant cooldown and depressurization. Heat is transferred from the reactor coolant system via the steam generators to the main steam system. Depressurization is accomplished by spraying reactor coolant into the pressurizer, which cools and condenses the pressurizer steam bubble.

When the reactor coolant temperature and pressure have been reduced to 350°F and 450 psig, respectively (approximately four hours after reactor shutdown), the second phase of plant cooldown is initiated with the normal residual heat removal system being placed in service.

Before starting the residual heat removal pumps, the in-containment refueling water storage tank isolation valve is closed. Then the normal residual heat removal system suction header isolation valve and the discharge header isolation valve are opened. When the pressure in the reactor coolant system has been reduced to below 450 psig, the inner/outer isolation valves are opened.

Once the proper valve alignment has been performed and component cooling water flow has been initiated to both residual heat removal heat exchangers, normal residual heat removal system operation may begin. The pumps are started and the cooldown proceeds. The cooldown rate is controlled by throttling the flow through the bypass around the heat exchanger based on reactor coolant temperature.

This mode of operation continues for the duration of the cooldown until the reactor coolant system temperature is reduced to 140°F and the system is depressurized. The reactor coolant system may then be opened for either maintenance or refueling. Cooldown continues until the reactor coolant system temperature is lowered to 125°F (about 96 hours after reactor shutdown).

During the cooldown operations, the reactor coolant system water level is drained to a “mid-loop” level to facilitate steam generator draining and maintenance activities. For normal refuelings, the level to which the reactor coolant system is drained is that which allows air to be vented into the steam generators from the pressurizer. This level is nominally an 80 percent water level in the hot leg. The design of the AP1000 normal residual heat removal system is such that throttling of the residual heat removal pump flow during mid-loop operations to avoid air-entrainment into the pump suction is not required.

At the appropriate time during the cooldown, the operator lowers the water level in the reactor coolant system by placing the chemical and volume control system letdown control valve into the “refueling draindown” mode. At this time the makeup pumps are turned off; and the letdown flow control valve controls the drain rate to the liquid waste processing system. The drain rate proceeds initially at the maximum drain rate and is substantially reduced once the level in the reactor coolant system is lowered to the top of the hot leg. The letdown flow control valve as well as the letdown line containment isolation valve receives a signal to automatically close once the appropriate level is attained. Alarms actuate in the main control room if the level continues to drop to alert the operator to manually isolate the letdown line.

5.4.7.4.3 Refueling

Both residual heat removal pumps and heat exchangers remain operating during refueling. Water transfers from the in-containment refueling water storage tank to the refueling cavity are performed by the spent fuel pool cooling system (SFS). This function has traditionally been performed by residual heat removal systems. That capability still exists if the need arises. To improve clarity in the refueling cavity and reduce operational radiation exposure, the spent fuel pool cooling system is used to flood the refueling cavity without flooding through the reactor vessel.

As decay heat decreases and as fuel is moved to the spent fuel pool, one residual heat removal pump and heat exchanger may be taken out of service. However, the valves remain aligned should the need arise to start this pump quickly in case of a failure of the operating residual heat removal pump.

5.4.7.4.4 Accident Recovery Operations

Upon actuation of automatic depressurization, the normal residual heat removal system can be employed to provide low-pressure reactor coolant system makeup. Provided that radiation levels inside containment are below a high radiation value and after resetting the safeguards actuation signal to the valves as necessary, the operator may open the cask loading pit suction valves and the residual heat removal discharge isolation valve and start the residual heat removal pumps. Water is pumped from the cask loading pit to the direct vessel injection lines. Operation of the normal residual heat removal system will not prevent the passive core cooling system from performing its safety functions.

5.4.7.4.5 Spent Fuel Pool Cooling

The normal residual heat removal system has the capability of being connected to supplement or take over the cooling function of the spent fuel pool cooling system. The normally closed valves in the cross-connecting piping are opened. One normal residual heat removal pump is started. Spent fuel pool water is drawn through the pump, passed through a heat exchanger and returned to the pool.

This mode of cooling is available when the normal residual heat removal system is not needed for normal shutdown cooling. The spent fuel pool water flow path between the spent fuel pool and the normal residual heat removal system is independent of the flow path used for spent fuel pool cooling by the spent fuel pool cooling system.

5.4.7.4.6 Fire Leading to MODE 5, Cold Shutdown

In the event of loss of normal component cooling system function where it is desired to transfer to MODE 5, Cold Shutdown, to facilitate maintenance, the fire protection system can provide the source of cooling water for a normal residual heat removal system pump and heat exchanger as described in subsection 9.2.2.4.5.5.

5.4.7.5 Design Evaluation

Since the normal residual heat removal system is connected to the reactor coolant system, portions of the system that create the reactor coolant system pressure boundary are designed according to ANSI/ANS 51.1 (Reference 6) with regards to maintaining the reactor coolant system pressure boundary integrity.

Since the normal residual heat removal system penetrates the containment boundary, the containment penetration lines are designed according to the containment isolation criteria identified in subsection 6.2.3.

Safety-related makeup water can be provided through the normal residual heat removal system for long-term post-accident containment makeup. This makeup is provided through the manual drain valve in the normal residual heat removal heat exchanger A.

The normal residual heat removal system components and piping are compatible with the radioactive fluids they contain.

The design of the normal residual heat removal system has been compared with the acceptance criteria set forth in subsection 5.4.7, "Residual Heat Removal System," Revision 3, of the NRC's Standard Review Plan. The specific General Design Criteria identified in the Standard Review Plan section are General Design Criteria 2, 4, 5, 19, and 34. Additionally, positions of Regulatory Guides 1.1, 1.29, and 1.68 were also reviewed to determine the degree of compliance between the AP1000 and the acceptance criteria. Branch Technical Position RSB 5-1 was also reviewed as appropriate.

Discussions of the conformance with Regulatory Guides and Branch Technical Positions are found in Section 1.9. Compliance with General Design Criteria is found Section 3.1.

5.4.7.6 Inspection and Testing Requirements

5.4.7.6.1 Preoperational Inspection and Testing

Preoperational tests are conducted to verify proper operation of the normal residual heat removal system (RNS). The preoperational tests include valve inspection and testing, flow testing, and verification of heat removal capability.

5.4.7.6.1.1 Valve Inspection and Testing

The inspection requirements of the normal residual heat removal system valves that constitute the reactor coolant pressure boundary are consistent with those identified in subsection 5.2.4. The inspection requirements of the normal residual heat removal system valves that isolate the lines penetrating containment are consistent with those identified in Section 6.6.

The low temperature overpressure protection relief valve, RNS-V021, located on the normal residual heat removal system suction relief line, is bench tested with water. Valve set pressure is verified to be less than or equal to the value assumed in the low temperature overpressure

protection analysis. Relieving capacity of the valve is certified in accordance with the ASME code, Section III, NC-7000.

5.4.7.6.1.2 Flow Testing

Each installed normal residual heat removal system pump is tested to measure the flow through the normal residual heat removal system heat exchangers when aligned to cool the reactor coolant system. Testing will be performed with the pump suction aligned to the reactor coolant system hot leg and the discharge aligned to the passive core cooling system direct vessel injection lines. Flow will be measured using instrumentation in the pump discharge line. Testing will confirm that each pump provides at least the required flow rate shown in Table 5.4-14. This is the minimum flow rate required to ensure that the normal residual heat removal system can meet its functional requirement of cooling the reactor during shutdown operations.

Each installed normal residual heat removal system pump is also tested to measure the flow when aligned to deliver low pressure makeup to the reactor coolant system. Testing will be performed with the pump suction aligned to the cask loading pit and the discharge aligned to the passive core cooling system direct vessel injection lines. Flow will be measured using instrumentation in the pump discharge line. The reactor coolant system will be at atmospheric pressure for this test. Testing will confirm that each pump provides at least the required flow rate shown in Table 5.4-14. This is the minimum flow rate required to ensure that the normal residual heat removal system can meet its functional requirement to prevent 4th stage ADS actuation for small breaks.

5.4.7.6.1.3 Heat Removal Capability Analysis

Heat exchanger manufacturer's test results and heat exchanger data will be used to perform an analysis to verify that the heat removal capability of each normal residual heat removal system heat exchanger, as measured by the product of the heat transfer coefficient and the effective heat transfer area, UA, is equal to or greater than the required value shown in Table 5.4-14. This is the minimum value required to ensure that the normal residual heat removal system can meet its functional requirement of cooling the reactor during shutdown operations.

5.4.7.7 Instrumentation Requirements

The normal residual heat removal system contains instrumentation to monitor system performance. System parameters necessary for system operation are monitored in the main control room including the following:

- Residual heat removal flow;
- Residual heat removal heat exchanger inlet and system outlet temperatures; and,
- Residual heat removal pump discharge pressure.

In addition, the reactor coolant system contains instrumentation to control and monitor the operations of the normal residual heat removal system. These include the following:

- Reactor coolant system wide range pressure; and,
- Reactor coolant system hot leg level.

Instrumentation is also provided to enable mid-loop operations to be performed from the main control room.

The motor-operated valves connected to the reactor coolant system hot leg are interlocked to prevent them from opening when reactor coolant system pressure exceeds 450 psig. These valves are also interlocked to prevent their being opened unless the isolation valve from the in-containment refueling water storage tank to the residual heat removal pump suction header is closed. Section 7.6 describes this interlock.

5.4.8 Valves

Valves in the reactor coolant system and safety-related valves in connecting systems provide the primary means for the flow of water into and out of the reactor coolant system. In the following paragraphs the design basis, description, evaluation and testing of ASME Code Class 1, 2 and 3 valves is discussed. This discussion includes safety-related valves not in the reactor coolant system because the valve requirements are independent of the system.

5.4.8.1 Design Bases

Valves within the reactor coolant system and safety-related valves in connected systems are designed, manufactured, and tested to meet the requirements of the ASME Code, Section III. As noted in Section 5.2, valves out to and including the second valve that is normally closed or capable of automatic or remote closure are part of the reactor coolant system. The reactor coolant pressure boundary valves are manufactured to the ASME Code Class 1 requirements. Valves of 1 inch and smaller in lines connected to the reactor coolant system are manufactured to Class 2 requirements when the flow is limited by a flow-limiting orifice.

Containment isolation valves are manufactured to ASME Code, Class 2 requirements. Other AP1000 equipment Class C safety-related valves are manufactured to ASME Code, Class 3 requirements. Safety-related valves in auxiliary systems are manufactured to ASME Code Class 2 and 3 requirements depending on their function and classification as outlined in subsection 3.2.2.

Table 5.4-15 provides design data for the reactor coolant pressure boundary valves. Valves and operators are sized to provide valve operation under the full range of design basis flow and pressure drop conditions, including recovery from potential mispositioning of the valves. Operating modes, normal operating and worst-case differential pressures, fluid temperature ranges, and environmental effects are considered in sizing valves and valve operators. Table 5.4-16 gives the normal and maximum differential pressure expected during opening and closing of motor-operated valves in the reactor coolant pressure boundary. Check valves considered part of the reactor coolant system are located inside the containment.

5.4.8.1.1 Check Valves Design and Qualification

Design basis and required operating conditions for safety-related check valves are established based on design conditions including the required system operating cycles to be experienced by the valve, environmental conditions under which the valve is required to function, and severe transient loadings expected during the life of the valve. The design conditions considered may

include water hammer and pipe break transients, sealing and leakage requirements, operating fluid conditions (including flow, velocity, temperature, and temperature gradient), maintenance requirements, time between major refurbishments, corrosion requirements, vibratory loading, planned testing methods, and test frequency, and periods of idle operation. Design conditions may include other requirements identified during plant detail design. The maximum loading resulting from the design conditions and transients are evaluated in accordance with the ASME Code, Section III Class 1 design requirements.

Active safety-related check valves include the capability to verify the movement of each check valve's obturator during inservice testing by observing a direct instrumentation indication of the valve position or by using non-intrusive test methods. This instrumentation provides nonintrusive check valve indication and may be either permanently or temporarily installed.

Check valve model and size selection are based on the systems flow conditions, installed location of the valve with respect to flow disturbance, and orientation of the valve in the piping system. Design features, surface finish, and materials can accommodate provisions for nonintrusive determination of disk position and potential valve degradation over time. Valve internal parts are designed with self-aligning features for the purpose of assured alignment after each valve opening. Qualification testing provides for the adequacy of the safety-related check valves under design conditions. This testing includes test data from the manufacturer, field test data and empirical test data supported by test or test (such as prototype) of similar valves where similarity is justified by technical data. Sampling size for the qualification test is justified by technical data.

For safety-related active check valves with extended structures functional qualification will be performed to demonstrate by test, by analysis or by a combination thereof, the ability to operate at the safety-related design conditions. This functional qualification will demonstrate the valve operability during and after loads representative of the maximum seismic and vibratory event. Check valve internal parts are analyzed for maximum design basis loading conditions in accordance with the requirements in ASME Code, Section III.

5.4.8.1.2 Motor-Operated Valves Design and Qualification

[*Design basis and required operating conditions are established for active safety-related motor-operated valves. Based on the design conditions the motor-operated valves will have a structural analysis performed to demonstrate their components are within the structural limits at the design conditions. The motor-operated valves are designed for a range of conditions up to the design conditions which includes fluid flow, differential pressure (including line break, if necessary), system pressure and temperature, ambient temperature, operating voltage range and stroke time. The sizing of the motor operators on the valves take into account diagnostic equipment accuracies, changes in output capability for increasing differential pressures and flow and ambient temperature and reduction in motor voltage, control switch repeatability, friction variations and other changes in parameters that could result in an increase in operating loads or a decrease in operator output.*]* Valves that are subjected to large temperature changes during operation and can have water or high pressure fluid trapped in the bonnet cavity are evaluated for pressure locking. Provisions are provided, as required to reduce the susceptibility to bonnet overpressurization, pressure locking, and thermal binding.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

[*The motor-operated valves have a functional qualification performed to demonstrate by test, by analysis or by a combination thereof, the ability to operate over a range up to the design conditions. This functional qualification will demonstrate the motor-operated valve capability during and after loads representative of the maximum seismic or vibratory event (as required to perform their intended function), demonstrate the valve sealing capability, demonstrate capability under cold and hot operating conditions, demonstrate capability under maximum pipe end loads and demonstrate flow interruption and functional capability. The testing includes test data provided by the manufacturer, field test data, empirical data supported by testing or analysis of prototype tests of similar motor-operated valves that support the qualification where similarity must be justified by technical data. The qualification must be used for validating the required thrust and torque as applicable to operate the valve and the output capability of the motor operator.*]*

Motor-operated valves are designed to be able to change their position from an improper position (mis-positioned) either prior to or during accidents. The recovery from mis-positioning is considered a nonsafety-related function. The nonsafety-related capability to recover from valve mis-positioning is provided for plant operational availability considerations. Systems with safety-related functions that contain motor-operated valves are designed to tolerate mis-positioning as a single failure or redundant features are provided to preclude mis-positioning. These features include multiple position indicators and alarms, technical specification surveillance, power lock-out, and confirmatory open or close signals.

Since recovery from mis-positioning is a nonsafety-related function, equipment qualification testing and inservice testing is not required for the recovery from mis-position function.

Provisions are made, where possible, for in-situ testing of motor-operated valves at a range of conditions up to the maximum design basis operating conditions in the safety-related design direction (open or close). Where an alternative to in-situ testing is required, the justification of the alternative method to design condition differential testing is documented as part of the valve test program.

5.4.8.1.3 Other Power-Operated Valves Including Explosively Actuated Valves Design and Qualification

Design basis and required operating conditions are established for power-operated (POV) and explosively actuated valve assemblies with an active safety-related function. Power-operated valve assemblies include pneumatic-hydraulic-, air piston-, and solenoid-operated assemblies. Explosively-actuated valves have the valve disk welded to the valve seat and are actuated by an explosive charge fired by an electrical signal.

[*The power operated safety related valves will have a structural analysis performed to demonstrate their components are within the structural limits at the design conditions. Power operated valve assemblies and explosively actuated valves are designed to accept the maximum compression, tension, and torsional loads which the assembly is capable of producing in combination with other loads such as pressure, thermal, or externally applied loads. The maximum loading resulting from the design conditions and transients is evaluated in accordance*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

with the ASME Code, Section III Class 1 design requirements. Packing adjustment limits are identified to reduce the potential for stem binding.

The power operated valves are designed to operated at design operating conditions which include fluid flow, differential pressure (including pipe break, if necessary), system pressure, fluid temperature, ambient temperature, fluid supply conditions (or electrical power supply), spring force and stroke time requirements. The power operated valves, depending on their design and actuation mode, have the operators sized to account for diagnostic equipment accuracies, changes in output capability for increasing differential pressures and flow, friction variations and changes in other parameters that could result in an increase in operating loads or a decrease in operator output.

The power-operated, safety-related valves have a functional qualification performed to demonstrate by test, by analysis or by a combination thereof, the ability to operate at the design conditions. Qualification testing of each size, type, and model is performed under a range of differential pressures and maximum achievable flow conditions up to the design conditions. This functional qualification will demonstrate the power-operated valves capability during and after loads representative of the maximum seismic or vibratory event (as required to perform their intended function), demonstrate the valve sealing capability, demonstrate capability under cold and hot operating conditions, demonstrate capability under maximum pipe end loads and demonstrate flow interruption and functional capability. The testing includes test data from the manufacturer, field test data, empirical data supported by test, or analysis of prototype tests of similar power-operated valves that support qualification of the power-operated valve. Similarity must be justified by technical data. Solenoid-operated valves are verified to satisfy the applicable requirements for Class 1E components. Solenoid-operated valves are verified to perform their safety-related design requirements over a range of electrical power supply conditions including minimum and maximum voltage.]*

5.4.8.2 Design Description

The materials of construction are selected to minimize the effects of corrosion and erosion and are compatible with the environment. The valves in contact with reactor coolant fluid shall be constructed of stainless steel materials or alloys acceptable for the fluid chemistry.

Safety-related valves do not have full penetration welds within the valve body walls except that explosive actuated valves may be fabricated using full penetration welds of the valve bodies.

Valves and actuators are furnished as a matched system capable of operating over the entire range of design basis conditions. The function of the valve and operator including switch settings for motor-operated valves are qualified by testing, analysis or a combination thereof.

Valves that have stem packing are constructed with packing material compatible with the system fluid and stem material. Where the design permits, valves greater than 2 inch diameter have live load packing to maintain a compressive packing force. Valves supplied with stem packing are supplied with a backseat which may be utilized to minimize stem leakage. The backseat capability does not rely on system pressure to achieve a satisfactory seal. Valve designs such as main steam isolation valves, safety relief valves, packless valves and small solenoid valves by nature of the

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

design of these valves do not have backseat capability. Motor operated valves are not backseated during normal operation. The backseating of the valve must not compromise the structural integrity of the valve and the backseats are capable of retaining the valve stem against full system pressure and maximum thrust produced by the actuator.

Gate valves at the interface with the reactor coolant system and connected safety-related systems are either of the wedge or parallel disc design and have essentially straight through flow. The wedge design is flex-wedge; solid wedge designs are not used. Gate valves have backseats. Gate valves that are susceptible to overpressurization as the result of the heatup of trapped fluid shall be provided with venting capability to alleviate the issue. The valve shall be of outside screw and yoke design. Gate valves are not used in flow regulation or throttling service.

Globe valves are either T or Y type of either a standard or balanced plug design. Valves that are used for throttling service are designed with a disc or disc/cage assembly that will provide the required flow characteristic. Motor operated and manual valves are of the outside screw and yoke design.

Check valves are typically swing type, but tilt disk, nozzle check, and lift check may be used. Check valves containing radioactive fluid are fabricated of stainless steel. These valves do not have body penetration other than the inlet, outlet and bonnet. The check hinge is serviced through the bonnet. Operating parts are contained within the body. The disc of swing check valves has limited rotation to provide a change of seating surface and alignment after each valve opening.

5.4.8.3 Design Evaluation

ASME Code, Class 1 valves meet the design requirements of ASME Code, Section III, Article NB-3000. ASME Code, Class 2 valves meet the design requirements of ASME Code, Section III, Article NC-3000. ASME Code Class 3 valves meet the design requirements of ASME Code, Section III, Article ND-3000. The AP1000 equipment Classes A, B, and C valves, which are manufactured to ASME Code Classes 1, 2, and 3 respectively, meet established functional requirements. The functional requirements include operability, differential pressure during opening or closure, and seat leakage. The functional requirements are consistent with the guidelines in Regulatory Guide 1.148 and ANSI N278.1-1975 (Reference 7).

The design transients for the valves including the number and the duration of each type of cycle are identified in subsection 3.9.1.1.

Valves with extended structures have testing or analysis performed to demonstrate that the natural frequency is greater than 33 hz. In addition, a structural analysis is performed to verify the design loading will not effect the intended operation of the valve.

Qualification testing of each power operated valve which includes motor-operated, air operated, hydraulic operated, solenoid operated and explosive actuated valves demonstrates the capability of the operator to operate over the full range of expected plant operating conditions. Qualification testing also demonstrates the closing, opening, and seating capability of the valve against the maximum pressure differential and flow within a specified time over the entire operating range. Requirements for qualification testing of power-operated active valves are based on

QME-1 (Reference 8). The testing programs in section 3.10 demonstrate the capability of the valves to operate, as required, during anticipated and postulated plant conditions.

Reactor coolant chemistry parameters are compatible with valve construction materials.

5.4.8.4 Tests and Inspections

The nondestructive examinations for the reactor coolant pressure boundary valves meet the more stringent requirements of the ASME Code, Section III, or ANSI B16.34 (Reference 9). The nondestructive examination required is evaluated for each type and class of valve. The examinations consist of the following:

- **Radiographic Examination -** Classes 1 and 2 valve bodies, bonnets, and discs which of cast material are radiographically examined in accordance with the ASME Code, Section III. The procedure and acceptance standards are according to the requirements for Class 1 in the ASME Code, Section III.

- **Ultrasonic Examination -** Classes 1 and 2 valve bodies, bonnets, and discs and Classes 1, 2, and 3 valve stems of 1 inch nominal diameter or larger fabricated of wrought or forged material are ultrasonically examined. The procedures and acceptance standards are according to the requirements for Class 1 in the ASME Code, Section III.

- **Liquid Penetrant Examination -** Bodies, bonnets, discs, and stems, including machined surfaces on these parts, are liquid-penetrant examined in accordance with the ASME Code, Section III. The procedures and acceptance standards are according to the requirements for Class 1 in the ASME Code, Section III.

Hydrostatic pressure boundary test and seat leakage are performed on the reactor coolant pressure boundary valves. The valves are subjected to the following tests as appropriate following manufacture: hydrostatic pressure boundary test, disc hydrostatic test, backseat leakage test, packing leakage test, stem leakage test, and main seat leakage test. Valves used for containment isolation are subjected to a pneumatic seat leakage test. Each diaphragm actuator assembly is subjected to a pneumatic leakage test.

Preoperational testing is performed on the valves to verify operability during design basis operating conditions. The preoperational testing is described in the following sections. The requirements of NRC Generic Letter 89-10 are used as guidelines to develop the preservice test program for valve operability. Except when test alternatives are justified, design conditions are used for the operability testing.

Subsection 5.2.4 discusses inservice inspection for ASME Code Class 1 valves. Section 6.6 discusses inservice inspection for ASME Code Class 2 and 3 components. Valves are accessible for disassembly and internal visual inspection to the extent practical. Subsection 3.9.6 discusses the inservice testing program for active valves.

5.4.8.5 Preoperational Testing

Results of preoperational testing will be used by the Combined License applicant to demonstrate that the results of testing under in situ or installed conditions can be used to confirm the capacity of the valve to operate under design conditions.

5.4.8.5.1 Check Valves

Active check valves are tested in the open and close direction. Testing a check valve confirms the valve operability to move to the position to fulfill the safety-related mission during applicable plant modes. The test shows that the check valve opens in response to flow and closes when the flow is stopped. Operability testing of the valves is described in subsection 3.9.3.2.2. Full-flow testing during applicable plant modes of check valves or sufficient flow to fully open the check valve to demonstrate valve operability under design conditions is permitted in most cases by the system design. Where this testing cannot be accomplished, an alternate method of demonstrating operability is developed, and justified. A demonstration of reverse-flow isolation of the check valves that is that the check valve closes when the flow is stopped is performed using direct means or diagnostics. The testing includes the effects of rapid pump starts and stops as required by expected system operating conditions.

The valves to be tested, the safety-related functions of the valves, and the type of testing to be done to verify the capability of the valves to perform the safety-related functions are outlined in valve inservice test requirements found in subsection 3.9.6 and Table 3.9-16. The valves to be tested, safety-related functions, and test requirements for preoperational testing are the same as outlined in inservice test requirements.

During pre-operational testing the following is verified to demonstrate the acceptability of the functional performance.

- The valves are verified to fully open or fully closed under design flow conditions.
- The disc movement from full open to full close is free.
- The valve leakage when fully closed is within established limits, as applicable.
- The disc is stable in the full open position at the system operating flow, conditions.
- The valve disc position can be verified without disassembly of the valve.
- The valve design features, surface finish and materials can accommodate nonintrusive diagnostic testing methods.
- The testing requirements in the inservice test plan can be accommodated in the piping system design.

5.4.8.5.2 Motor-Operated Valves

[*Active safety-related motor-operated valves are tested to verify that the valves open and close under static and safety-related design conditions. Where the safety-related design conditions cannot be achieved, the testing is performed at the maximum achievable dynamic conditions. During the testing critical parameters needed to determine the required closing and opening loads are measured These parameters include thrust, torque, travel, differential pressure, system pressure, fluid flow, voltage, temperature, operating time and thrust/torque at seating, unwedging and at control switch trip. The data collected during the testing on the parameters is used to determine the required operator loads and output capability for the design operating conditions in conjunction with the diagnostic equipment inaccuracies, load changes for increasing differential pressures and flow and ambient temperature and reduction in motor voltage, control switch repeatability, friction variations and changes in other parameters that could result in an increase in operating loads or decrease in operator output capability. The resulting operating loads including uncertainties are then compared to the structural capabilities of the motor-operated valve.*]* Active safety-related motor-operated valves are tested prior to operation for operability as described in subsection 3.9.3.2.2.

Pre-operational testing and evaluation is used to demonstrate the acceptability of the valves functional performance including the following.

- The valves are verified to open and close as applicable at a range of safety-related conditions up to the design conditions to perform their safety function.
- The control switch settings must be adequate to provide margin for diagnostic accuracy, control switch repeatability, load sensitive behavior and degradation.
- The motor operator capability at degraded voltage must exceed the required operating loads and the loads at the control switch settings including diagnostic equipment inaccuracies, load changes for increasing differential pressures and flow, control switch repeatability, friction variations and other parameters that could result in an increase in operating loads or decrease in operator output capability.
- The maximum operating loads including diagnostic equipment inaccuracies, load changes for increasing differential pressures and flow, control switch repeatability, friction variations and other parameters that could result in an increase in operating loads or decrease in operator output capability are verified not to exceed the allowable structural capability limits of the motor-operated valve components.
- The stroke time measurements during opening and closing must be within the design requirements if stroke time is important to the safety function.
- The remote position indication is verified against the local position indication.
- The valve leakage when fully closed is within established limits, as applicable.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

5.4.8.5.3 Power Operated Valves

[*Active safety related power-operated valve assemblies are tested to verify that the valve opens and closes under static and design conditions. Where the design conditions cannot be achieved, the testing is performed at the maximum achievable dynamic conditions. During the testing, critical parameters needed to determine the required closing and opening loads are measured. These parameters include seat load, torque or thrust, travel, spring rate, differential pressure, system pressure, fluid flow, temperature, power supply, operating time and minimum supply pressure. The data collected during the testing on the parameters is used to determine the required operating loads for the design operating conditions in conjunction with the diagnostic equipment inaccuracies and other parameters that could result in an increase in operating loads or decrease in operator output capability. The resulting operating loads including uncertainties are then compared to the structural capabilities of the power-operated valve.*]*

During pre-operational testing the following are verified to demonstrate the acceptability of the functional performance.

- The valves are verified to open and close as applicable at a range of conditions up to the design conditions to perform its safety function.

- For air-operated valves and hydraulically-operated valves the operator capability at minimum supply pressure, power supply or loss of motive force exceed the required operating loads including diagnostic equipment inaccuracies and other parameters that could result in an increase in operating loads or decrease in operator output capability.

- For solenoid-operated valves the valve must be capable of opening or closing the valve at the minimum power supply.

- For air-operated valves and hydraulically-operated valves the maximum operating loads including diagnostic equipment inaccuracies and other parameters that could result in an increase in operating loads are verified not to exceed the allowable structural capability limits of the power-operated valve components.

- The stroke time measurements during opening and closing must be within the design requirements for safety-related functions.

- The remote position indication is verified against the local position indication.

- The valve leakage when fully closed is within established limits, as applicable.

5.4.9 Reactor Coolant System Pressure Relief Devices

Safety valves connected to the pressurizer provide overpressure protection for the reactor coolant system during power operation. The relief valve on the suction line of the normal residual heat removal system (RNS) provides low temperature overpressure protection consistent with the guidelines of NRC Branch Technical Position RSB 5-2. The following discusses the requirements for the valves. Sizing of the safety valves is discussed in subsection 5.2.2.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Power-operated relief valves are not provided in the AP1000 reactor coolant system. Non-reclosing pressure relief devices are not used for pressure relief on the AP1000 reactor coolant system. Section 10.3 discusses safety valves for the main steam system. The automatic depressurization valves which are also connected to the pressurizer and are the interface with the passive core cooling system, are not pressure relief devices. (See subsection 5.4.6.)

5.4.9.1 Design Bases

The combined capacity of the pressurizer safety valves can accommodate the maximum pressurizer surge resulting from complete loss of load. The safety valve on the suction line of the normal residual heat removal system can accommodate the flow from both makeup pumps with no letdown and a water-solid reactor coolant system during low-temperature modes. Table 5.4-17 gives design parameters for the pressurizer safety valves and the residual heat removal system relief valve.

Use of the pressurizer safety valves and the normal residual heat removal relief valve at elevated temperatures in post-accident environments is not anticipated.

5.4.9.2 Design Description

The pressurizer safety valves and the normal residual heat removal system relief valve are spring loaded, self-actuated by direct fluid pressure, and have backpressure compensation features. These valves are designed to reclose and prevent further flow of fluid after normal conditions have been restored. The pressurizer safety valves are of the totally enclosed pop type. The normal residual heat removal relief valve is designed for water relief.

The pressurizer safety valves are incorporated in the pressurizer safety and relief valve (PSARV) module, which provides the connection to the pressurizer nozzles. The routing of pipe between the pressurizer and the safety valves does not include a loop seal. Any condensation of steam in the connecting pipe up to the valve rains back to the pressurizer. Condensate does not collect as a slug of water to be discharged during the initial opening of the valve. The discharge of the safety valve is routed through a rupture disk to containment atmosphere. The rupture disk is provided to contain leakage past the valve, is designed for a substantially lower set pressure than the safety valve set pressure, and does not function as a relief device. The reactor coolant system Piping and Instrumentation Drawing (Figure 5.1-1) shows the arrangement of the safety valves.

The relief valve in the normal residual heat removal system is located between the suction line of the pump and the valve that isolates the residual heat removal system from the reactor coolant system. The discharge from that valve is directed to the containment atmosphere. Subsection 5.4.7 discusses the residual heat removal system. Figure 5.4-6 shows a simplified sketch of the normal residual heat removal system.

In accordance with the requirements of 10 CFR 50.34(f)(2)(xi), positive position indication is provided for the pressurizer safety valves and the normal residual heat removal system relief valve, which provide overpressure protection for the reactor coolant pressure boundary.

Temperatures in the safety valve discharge lines are measured, and an indication and a high temperature alarm are provided in the control room. An increase in a discharge line temperature is

an indication of leakage or relief through the associated valve. Leakage past the pressurizer safety valve during normal operation is collected and directed to the reactor coolant drain tank. Section 7.5 discusses the functional requirements for the instrumentation required to monitor the safety valves.

5.4.9.3 Design Evaluation

The pressurizer safety valves prevent reactor coolant system pressure from exceeding 110 percent of system design pressure, in compliance with the ASME Code, Section III. The relief valve on the suction line of the normal residual heat removal system protects that system from exceeding 110 percent of the design pressure of the system and from exceeding the pressure-temperature limits determined from ASME Code, Appendix G, analyses.

The reactor coolant system pressure transients are described in subsection 15.2.3 and are the basis for the ASME Code Overpressure Protection Report. In the analysis of overpressure events, the pressurizer safety valves are assumed to actuate at 2500 psia. The safety valve flowrate assumed is based on full flow at 2575 psia, assuming 3 percent accumulation.

In certain design basis events described in Chapter 15, the pressurizer safety valves are predicted to operate with very low flow rates. For these events, the reactor coolant system pressure is slowly increasing as a result of the mismatch between the decay heat removal rate from the passive residual heat removal heat exchanger and the core decay heat. This slow pressurization of the reactor coolant system results in a small amount of steam flow through the safety valves. Under these conditions, the safety valves do not fully open and would not experience significant cycling. Operation of the safety valves under these conditions could result in small leakage from the valve (much less than the capacity of the normal makeup system), but does not impair the valve overpressure protection capability.

The relief valve on the normal residual heat removal system has an accumulation of 10 percent of the set pressure. The set pressure is the lower of the pressure based on the design pressure of the residual heat removal system and the pressure based on the reactor vessel low temperature pressure limit. The pressure limit determined based on the design pressure includes the effect of the pressure rise across the pump. The set pressure in Table 5.4-17 is based on the reactor vessel low temperature pressure limit. The lowest permissible set pressure is based on the required net positive suction head for the reactor coolant pump.

5.4.9.4 Tests and Inspections

The safety and relief valves are the subject of a variety of tests to validate the design and to verify pressure boundary and functional integrity. For valves that are required to function during a Service Level D condition, static deflection tests are performed to demonstrate operability. Section 3.10 describes these tests.

Safety valves similar to those connected to the pressurizer have been tested within the Electric Power Research Institute (EPRI) safety and relief valve test program. Capacity data for the specific AP1000 safety valve size has been correlated with the EPRI test data to demonstrate that the valve is adequate for steam flow and water flow, even though water flow is not anticipated through the pressurizer safety valves. The completion of this program addresses the requirements

of 10 CFR 50.34(f)(2)(x) as related to reactor coolant system relief and safety valve testing. The normal residual heat removal system relief valve is designed for water relief and is not a reactor coolant system pressure relief device since it has a set pressure less than reactor coolant system design pressure. Therefore, the valve selected for the normal residual heat removal system relief valve is independent from the Electric Power Research Institute safety and relief valve test program.

Reactor coolant system pressure relief devices are subjected to preservice and inservice hydrostatic tests, seat leakage tests, operational tests, and inspections, as required. The preservice and inservice inspection and testing programs for valves are described in subsections 3.9.6 and 5.4.8 and Section 6.6. The test program for the safety valves complies with the requirements of ANSI/ASME OM, Part 1.

The pressure boundary portion of the valves are required to be inservice inspected according to the rules of Section XI of the ASME Code. There are no full-penetration welds within the valve body walls. Valves are accessible for disassembly and internal visual inspection.

Type testing of the pressurizer safety valves is performed to verify that the pressurizer safety valves operate with low flow at pressures near the valve set pressure. Type tests are performed to correlate the leakage through the safety valves as a function of inlet pressure, at pressures near the valve set pressure. This testing is performed to verify that the safety valves operate in a stable manner at low flow rates. The testing correlates leakage through the valve as a function of inlet pressure and demonstrates that the leakage through the safety valves at set pressure conditions will be greater than or equal to that modeled in the accident analyses. The testing demonstrates that the valves leak at a flow rate of at least 0.35 lbm/sec at a pressure below the valve full-open pressure. The valve full-open pressure is the pressure at which the safety valve opens with significant blowdown flow. The duration of the testing need not duplicate the times indicated in the accident analysis results but should last for a sufficient time to demonstrate stable valve operation. Stable valve performance without excessive valve cycling or chattering for a 15 minute time duration is sufficient. Following this testing, the valve integrity is demonstrated, and the valve leakage is required to be less than the makeup capability of the chemical and volume control system makeup pumps.

5.4.10 Component Supports

5.4.10.1 Design Bases

Component supports provide deadweight support for the piping and equipment, allow lateral thermal movement of the loop during plant operation, and restrain the loops and components during accident and seismic conditions. Subsection 3.9.3 discusses the loading combinations and design stress limits. Support design is according to the ASME Code, Section III, Subsection NF.

The design provides for the integrity of the reactor coolant pressure boundary for normal, seismic, and accident conditions. The design also maintains the piping stresses less than ASME Code limits and less than the limits required to support mechanistic pipe break discussed in subsection 3.6.3.

Section 3.9 presents the results of piping and supports stress evaluations. The loads associated with the dynamic effects of postulated pipe rupture for pipes 6" and larger, which satisfied the requirements for mechanistic pipe break, are not included. See subsection 3.6.3.

The edition of the ASME code, Section III, subsection NF, which is used as the baseline requirement, address the guidance of Regulatory Guides 1.124 and 1.130. The plant design is in conformance with these requirements of the ASME Code. Conformance with Regulatory Guides 1.124 and 1.130 is discussed in detail in Section 1.9. The embedded portions of the component supports are designed according to AISC N690 and ACI 349, as discussed in subsection 3.8.3.

5.4.10.2 Design Description

The support structures are welded, structural steel sections. Linear structures (tension and compression struts, columns, and beams) are used except for the reactor vessel supports, which are plate-and-shell-type structures. Attachments to the supported equipment are either integral (welded to the component) or non-integral (pinned to, bolted to, or borne against the components). The supports-to-concrete attachments are either brackets welded to heavy embedded plates or anchor bolts or are embedded fabricated assemblies.

The supports permit thermal growth of the supported systems but restrain vertical and lateral movement resulting from seismic and pipe-break loadings. This is accomplished by using pinned ends in the vertical support columns, girders, bumper pedestals, and hydraulic snubbers, and lateral struts.

Because of manufacturing and construction tolerances, ample adjustment for the support structures provides proper erection alignment and fit-up. This is accomplished by shimming or grouting at the supports-to-concrete interface and by shimming at the supports-to-equipment interface.

The supports for the various components are described in the following paragraphs.

5.4.10.2.1 Reactor Pressure Vessel

The reactor vessel supports consist of four individual, air-cooled steel box structures located beneath the inlet nozzles (See Figure 3.8.3-4). The boxes are air-cooled to achieve a concrete design temperature of 200°F. To reduce heat transfer from the nozzle to the concrete, cooled air is baffled vertically through the support, and the heated air is vented at the top.

Vertical and horizontal loads are transmitted from the reactor vessel nozzle pad to the box structure through an integral “shoe” machined into the top of the box. The nozzle pad bears on permanently lubricated wear plates that allow radial thermal movements of the nozzle with minimal friction resistance to the movement. The vessel support boxes transfer loads from the reactor pressure vessel to vertical and horizontal embedments in the primary shield wall concrete.

5.4.10.2.2 Steam Generator

As shown in Figure 3.8.3-5, each steam generator support consists of the following:

Vertical Support

The vertical support consists of a single vertical column extending from the steam generator compartment floor to the bottom of each steam generator channel head. The column is constructed of a heavy wide flange section, and is pinned at both ends to permit thermal movement of each steam generator during plant heatup and cooldown. The column is located so that it allows full access to the steam generator for routine maintenance activities. It is located far enough from the reactor coolant pump motors to permit pump maintenance and inservice inspection.

Lower Lateral Support

The lower horizontal support is located at the bottom of the channel head. It consists of a tension/compression strut oriented nearly perpendicular to the hot leg. The strut is pinned at both the wall bracket and the steam generator channel head to permit movement of the steam generator during plant heatup and cooldown.

Upper Lateral Support

The upper horizontal support in the direction of the hot leg is located on the upper shell just above the transition cone. It consists of two large hydraulic snubbers oriented parallel with the hot leg centerline. One snubber is mounted on each side of the generator on top of the steam generator compartment wall. The hydraulic snubbers are valved to permit relatively unrestricted steam generator movement during thermal transient conditions, and to “lock up” and act as a rigid strut under dynamic loads.

The upper steam generator horizontal support in the direction normal to the hot leg is located on the lower shell just below the transition cone. It consists of two rigid struts oriented perpendicular to the hot leg. The two rigid struts are mounted on the steam generator compartment wall at the elevation of the operating deck. The steam generator loads are transferred to the struts and snubbers through trunnions on the generator shell.

5.4.10.2.3 Reactor Coolant Pump

The reactor coolant pumps are supported entirely by the steam generators; consequently, there are no reactor coolant pump supports.

5.4.10.2.4 Pressurizer

The supports for the pressurizer, as shown in Figure 3.8.3-3, consist of the following:

- Four steel columns attached to the lower head to provide vertical support for the pressurizer. Struts connected to the lower head and surrounding walls provide lateral support.

- The upper lateral support consists of a box-type ring girder that surrounds the pressurizer. The support connects to the corners of the pressurizer cubicle walls with eight standard sway struts. The girder rests on and is supported vertically by the pressurizer valve support brackets. The pressurizer upper support also supports the pressurizer safety relief piping and valve module, in addition to providing lateral support to the pressurizer.

5.4.10.2.5 Control Rod Drive Mechanism Supports

The support for the control rod drive mechanism is provided by the integrated head package, as described in subsection 3.9.7.

5.4.10.3 Design Evaluation

An evaluation verifies the design adequacy and structural integrity of the reactor coolant loop and the primary equipment supports system. This evaluation compares the analytical results with established criteria for acceptability. Structural analyses demonstrate design adequacy for safety and reliability of the plant in case of a seismic disturbance, and/or loss of coolant accident conditions. Loads that the system is expected to encounter during its lifetime (thermal, weight, and pressure) are applied, and stresses are compared to allowable values. Subsection 3.9.3 discusses the modeling and analysis methods.

5.4.10.4 Tests and Inspections

Nondestructive examinations are performed according to the procedures of the ASME Code, Section V, except as modified by the ASME Code, Section III, Subsection NF.

5.4.11 Pressurizer Relief Discharge

The AP1000 does not have a pressurizer relief discharge system. The AP1000 has neither power operated pressurizer relief valves nor a pressurizer relief discharge tank. Some of the functions provided by the pressurizer relief discharge system in previous nuclear power plants are provided by portions of other systems in the AP1000.

The safety valves connected to the top of the pressurizer provide for overpressure protection of the reactor coolant system. First-, second-, and third-stage automatic depressurization system valves provide for depressurization of the reactor coolant system and venting of noncondensable gases in the pressurizer following an accident. These functions are discussed in subsections 5.2.2, 5.4.12, and in Section 6.3. The AP1000 does not have power operated relief valves connected to the pressurizer.

The discharge of the safety valves is directed through a rupture disk to containment atmosphere.

The discharge of the first-, second-, and third-stage automatic depressurization system valves is directed to the in-containment refueling water storage tank. For the automatic depressurization system valves, the following discussion considers only the gas venting function. Only the first stage automatic depressurization valves are used to vent non-condensible gases following an accident. The sizing considerations and design basis for the in-containment refueling water storage tank for the depressurization function are discussed throughout Section 6.3. The provisions to

minimize the differential pressure between the containment atmosphere and the interior of the in-containment refueling water storage tank are also discussed in subsection 6.3.2.

The safety valve on the normal residual heat removal system, which provides low temperature overpressure protection, discharges into the containment atmosphere. See subsection 5.4.7 for a discussion of the connections to and location of the safety valve in the normal residual heat removal system.

5.4.11.1 Design Bases

The containment has the capability to absorb the pressure increase and heat load resulting from the discharge of the safety valves to containment atmosphere. The in-containment refueling water storage tank has the capability to absorb the pressure increase and heat load from the discharge, including the water seal, steam and gases, from a first-stage automatic depressurization system valve when used to vent noncondensable gases from the pressurizer following an accident. The venting of noncondensable gases from the pressurizer following an accident is not a safety-related function.

5.4.11.2 System Description

Each safety valve discharge is directed to a rupture disk at the end of the discharge piping. A small pipe is connected to the discharge piping to drain away condensed steam leaking past the safety valve. The discharge is directed away from any safety related equipment, structures, or supports that could be damaged to the extent that emergency plant shutdown is prevented by such a discharge.

The discharge from each of two groups of automatic depressurization system valves is connected to a separate sparger below the water level in the in-containment refueling water storage tank. The piping and instrumentation diagram for the connection between the automatic depressurization system valves and the in-containment refueling water storage tank is shown in Figure 6.3-1. The in-containment refueling water storage tank is a stainless steel lined compartment integrated into the containment interior structure. The discharge of water, steam, and gases from the first-stage automatic depressurization system valves when used to vent noncondensable gases does not result in pressure in excess of the in-containment refueling water storage tank design pressure. Additionally, vents on the top of the tank protect the tank from overpressure, as described in subsection 6.3.2.

Overflow provisions prevent overfilling of the tank. The overflow is directed into the refueling cavity. The in-containment refueling water storage tank does not have a cover gas and does not require a connection to the waste gas processing system. The normal residual heat removal system provides nonsafety-related cooling of the in-containment refueling water storage tank.

5.4.11.3 Safety Evaluation

The design of the control for the reactor coolant system and the volume of the pressurizer is such that a discharge from the safety valves is not expected. The containment design pressure, which is based on loss of coolant accident considerations, is greatly in excess of the pressure that would result from the discharge of a pressurizer safety valve. The heat load resulting from a discharge of

a pressurizer safety valve is considerably less than the capacity of the passive containment cooling system or the fan coolers. See Section 6.2.

Venting of noncondensable gases, including entrained steam and water from the loop seals in the lines to the automatic depressurizations system valves, from the pressurizer into spargers below the water line in the in-containment refueling water storage tank does not result in a significant increase in the pressure or water temperature. The in-containment refueling water storage tank is not susceptible to vacuum conditions resulting from the cooling of hot water in the tank, as described in subsection 6.3.2. The in-containment refueling water storage tank has capacity in excess of that required for venting of noncondensable gases from the pressurizer following an accident.

5.4.11.4 Instrumentation Requirements

The instrumentation for the safety valve discharge pipe, containment, and in-containment refueling water storage tank are discussed in subsections 5.2.5, 5.4.9, and in Sections 6.2 and 6.3, respectively. Separate instrumentation for the monitoring of the discharge of noncondensable gases in not required.

5.4.11.5 Inspection and Testing Requirements

Sections 6.2 and 6.3 discuss the requirements for inspection and testing of the containment and in-containment refueling water storage tank, including operational testing of the spargers. Separate testing is not required for the noncondensable gas venting function.

5.4.12 Reactor Coolant System High Point Vents

The requirements for high point vents are provided for the AP1000 by the reactor vessel head vent valves and the automatic depressurization system valves. The primary function of the reactor vessel head vent is for use during plant startup to properly fill the reactor coolant system and vessel head. Both reactor vessel head vent valves and the automatic depressurization system valves may be activated and controlled from the main control room. The AP1000 does not require use of a reactor vessel head vent to provide safety-related core cooling following a postulated accident.

The reactor vessel head vent valves (Figure 5.4-8) can remove noncondensable gases or steam from the reactor vessel head to mitigate a possible condition of inadequate core cooling or impaired natural circulation through the steam generators resulting from the accumulation of noncondensable gases in the reactor coolant system. The design of the reactor vessel head vent system is in accordance with the requirements of 10 CFR 50.34 (f)(2)(vi).

The reactor vessel head vent valves can be operated from the main control room to provide an emergency letdown path which is used to prevent pressurizer overfill following long-term loss of heat sink events. An orifice is provided downstream of each set of head vent valves to limit the emergency letdown flow rate.

The first stage valves of the automatic depressurization system are attached to the pressurizer and provide the capability of removing noncondensable gases from the pressurizer steam space

following an accident. Venting of noncondensable gases from the pressurizer steam space is not required to provide safety-related core cooling following a postulated accident. Gas accumulations are removed by remote manual operation of the first stage automatic depressurization system valves.

The discharge of the automatic depressurization system valves is directed to the in-containment refueling water storage tank. Subsection 5.4.6 and Section 6.3 discuss the automatic depressurization system valves and discharge system.

The passive residual heat removal heat exchanger piping and the core makeup tank inlet piping in the passive core cooling system include high point vents that provide the capability of removing noncondensable gases that could interfere with heat exchanger or core makeup tank operation. These gases are normally expected to accumulate when the reactor coolant system is refilled and pressurized following refueling shutdown. Any noncondensable gases that collect in these high points can be manually vented.

The discharge of the passive residual heat removal heat exchanger high point vent is directed to the in-containment refueling water storage tank. The discharge of the core makeup tank high point vent is directed to the reactor coolant drain tank. Section 6.3 discusses the passive residual heat removal heat exchanger and venting capability, which is part of the passive core cooling system.

5.4.12.1 Design Bases

The reactor vessel head vent arrangement is designed to remove noncondensable gases or steam from the reactor coolant system via remote manual operations from the main control room through a pair of valves. The system discharges to the in-containment refueling water storage tank (IRWST).

The reactor vessel head vent system is designed to provide an emergency letdown path that can be used to prevent long-term pressurizer overfill following loss of heat sink events. The reactor vessel head vent is designed to limit the emergency letdown flow rate to within the capabilities of the normal makeup system. The reactor vessel head vent system can also vent noncondensable gases from the reactor head in case of a severe accident.

The system vents the reactor vessel head by using only safety-related equipment. The reactor vessel head vent system satisfies applicable requirements and industry standards, including ASME Code classifications, safety classifications, single-failure criteria, and environmental qualification.

The piping and equipment from the vessel head vent up to and including the second isolation valve are designed and fabricated according to ASME Codes Section III, Class 1 requirements. The remainder of the piping and equipment are design and fabricated in accordance with ASME Code, Section III, Class 3 requirements.

The supports and support structures conform with the applicable requirements of the ASME Code.

The Class 1 piping used for the reactor vessel head vent is 1-inch schedule 160. In accordance with ASME Section III it is analyzed following the procedures of NC-3600 for Class 2 piping.

The piping stresses meet the requirements of ASME Code, Section III, NC-3600, with a design temperature of 650°F and a design pressure of 2485 psig.

The automatic depressurization system functions as a part of the passive core cooling system. The first stage automatic depressurization system valves are connected to the pressurizer. The valves are designed, constructed, and inspected to ASME Code Class 1 and seismic Category I requirements. Subsection 5.4.6 and Section 6.3 discuss the design bases for the automatic depressurization system and automatic depressurization system valves.

The primary function of the passive residual heat removal heat exchanger and core makeup tank high point vents is to prevent accumulation of noncondensable gases from the reactor coolant system that could interfere with operation of the passive core cooling system. Section 6.3 discusses the design bases for the passive residual heat removal heat exchanger, the core makeup tanks, and their vent lines.

5.4.12.2 System Description

The reactor vessel head vent arrangement consists of two flow paths, each with redundant isolation valves. Orifices are located downstream of each set of head vent isolation valves to limit the reactor vessel head vent flow rate. Table 5.4-18 lists the equipment design parameters. The reactor vessel head vent arrangement is shown on the reactor coolant system piping and instrumentation diagram (Figure 5.1-5).

The head vent arrangement consists of two parallel paths of two 1-inch, open/close, solenoid-operated isolation valves connected to a 1-inch vent pipe 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 solenoid-operated isolation valves are powered by the safety-related Class 1E DC and UPS system. The solenoid-operated isolation valves are fail-closed, normally closed valves. The valves are included in the valve operability program and are qualified to IEEE-323, IEEE-344, and IEEE-382.

The vent system piping is supported such that the resulting loads and stresses on the piping and on the vent connection to the vessel head are acceptable.

The automatic depressurization system valves are included as part of the pressurizer safety and relief valve module attached to the top of the pressurizer and are connected to the pressurizer nozzles. The automatic depressurization system includes a group of valves attached to the reactor coolant system hot leg that are not used to vent noncondensable gases. The pressurizer safety and relief valve module is supported by an attachment to the top of the pressurizer and provides support for the automatic depressurization system valves. The automatic depressurization system valves are active valves required to provide safe shutdown or to mitigate the consequences of postulated accidents. Subsection 5.4.6 discusses the function control and power requirements for the automatic depressurization system valves.

5.4.12.3 Safety Evaluation

The reactor vessel head vent system is designed so that a single failure of the remotely operated vent valves, power supply, or control system does not prevent isolation of the vent path. The two isolation valves in the active flow path provide a redundant method of isolating the venting system. With two valves in series, the failure of any one valve does not inadvertently open a vent path or prevent isolation of a flow path. The DCD Chapter 15 accident analysis and supporting analyses are performed consistent with the reactor vessel head vent system design parameters provided in Table 5.4-18.

The reactor vessel head vent system has two normally de-energized valves in series in each flow path. This arrangement eliminates the possibility of opening a flow path due to the spurious movement of one valve.

A break of the reactor vessel head vent system line would result in a small loss of coolant accident of not greater than one-inch diameter. Such a break is similar to those analyzed in subsection 15.6.5. Since a break in the head vent line would behave similarly to the hot leg break case presented in subsection 15.6.5, the results presented therein apply to a reactor vessel head vent system line break. This postulated vent line results in no calculated core uncovery.

Subsection 5.4.6 and Section 6.3 discuss the evaluation of the automatic depressurization system valves. Inadvertent opening of an automatic depressurization system valve is included in the transients considered for specification of the inadvertent reactor coolant system depressurization in subsection 3.9.1.

Section 6.3 discusses the evaluation of the passive residual heat removal heat exchanger and core makeup tanks. These high point vent lines contain two manual isolation valves in series, so that a single failure of either valve to reclose following venting operation does not prevent isolation of the flow path. The high point vent line from the passive residual heat removal heat exchanger to the in-containment refueling water storage tank contains a flow-restricting orifice such that postulated break flow is within the makeup capability of the chemical and volume control system and therefore would not normally require actuation of the passive safety systems.

5.4.12.4 Inspection and Testing Requirements

Inservice inspection of ASME Code Classes 2 and 3 components is conducted according to Section 6.6. Subsection 3.9.6 discusses inservice testing and inspection of valves. Subsection 5.2.4 discusses inservice inspection and testing of ASME Code, Class 1 components that are part of the reactor coolant pressure boundary.

The requirements for tests and inspections for reactor coolant system valves is found in subsection 5.4.8.4. In addition, tests for the reactor vessel head vent valves and piping are conducted during preoperational testing of the reactor coolant system, as discussed in Section 14.2.

5.4.12.4.1 Flow Testing

Initial verification of the capacity of the reactor vessel head vent valves is performed during the plant initial test program. A low pressure flow test and associated analysis is conducted to determine the capacity of each reactor vessel head vent flow path. The reactor coolant system is at cold conditions with the pressurizer full of water. The normal residual heat removal pumps is used to provide injection flow into the reactor coolant system, discharging through the reactor vessel head vent valves. The measured flow rate at low pressure is such that the head vent flow capacity is at least 8.2 lbm/sec at an RCS pressure of 1250 psia.

5.4.12.5 Instrumentation Requirements

The reactor head vent valves can be operated from the control room or the remote shutdown workstation. The isolation valves in the vent line and automatic depressurization system valves have position sensors. The position indication from each solenoid-operated isolation valve is monitored in the control room.

5.4.13 Core Makeup Tank

The core makeup tank (CMT) in the passive core cooling system stores cold borated water under system pressure for high pressure reactor coolant makeup. See Section 6.3 for a discussion of the operation of the core makeup tank in the passive core cooling system and the connections to the core makeup tank.

5.4.13.1 Design Bases

The core makeup tank is designed and fabricated according to the ASME Code, Section III as a Class 1 component. See subsection 5.2.1. The boundaries of the ASME Code include the pressure-containing materials up to, but excluding, the circumferential welds at nozzle safe ends. The manway cover and bolting materials are included within this boundary. The core makeup tank is AP1000 equipment Class A (ANS Safety Class 1, Quality Group A). Stresses are maintained within the limits of the ASME Code, Section III. Section 5.2 provides the ASME Code and material requirements. Subsection 5.2.4 discusses inservice inspection.

Materials of construction are specified to minimize corrosion/erosion and to provide compatibility with the operating environment, including the expected radiation level. Subsection 5.2.3 discusses the welding, cutting, heat treating and other processes used to minimize sensitization of stainless steel.

Instrumentation nozzles are welded to the clad inside wall of the vessel according to ASME Code, Section III. Butt welds, branch connection nozzle welds, and boss welds are of a full-penetration design. Flanges conform to ANSI B16.5.

The transients used to evaluate the core makeup tank are based on the system design transients described in subsection 3.9.1.1. In addition to normal reactor coolant system transients, two additional Service Level B transients affect only the core makeup tank. There are an assumed 30 occurrences of the first transient, leakage at power, in the plant lifetime. This event covers situations which a small leak draws in hot reactor coolant system fluid. There are an assumed

10 occurrences in the plant lifetime of the second transient, increase in containment temperature above normal operating range.

5.4.13.2 Design Description

The core makeup tank is a low-alloy steel vessel with 308L stainless steel internal cladding. The minimum free internal volume for the core makeup tank is 2500 cubic feet. The normal full-power temperature and pressure in the core makeup tank are 70° to 120°F and 2250 psia, respectively. The tank is designed to withstand the design environment of 2500 psia and 650°F. The core makeup tank is a vertically mounted, cylindrical pressure vessel with hemispherical top and bottom heads.

The core makeup tank is supported on columns. One nozzle on the lower head connects the tank to the reactor vessel direct vessel injection (DVI) piping. One nozzle in the center of the upper head connects the tank to a line connected to one of the RCS cold legs. The top nozzle incorporates a diffuser inside the tank. The diffuser has the same diameter and thickness as the connecting piping. The bottom of the diffuser is plugged and holes are drilled in the side. The diffuser forces the steam flow to turn 90 degrees which limits the steam penetration into the coolant in the core makeup tank. The core makeup tank includes a manway and cover in the shell to allow access to the tank interior.

To maintain system pressure, the flowpath from the reactor coolant system cold leg to the upper head of the core makeup tank is normally open. The core makeup tank discharge piping flow path from the lower head to the reactor vessel is blocked by two normally closed, fail-open, parallel isolation valves. See Section 6.3 for a description of the system operation.

The tank includes nozzles and flanges for connection to level detection instrumentation.

Two sample lines, one in the upper head and the other in the lower head, are provided for sampling the solution in the core makeup tank. A fill connection is provided for core makeup tank make up water from the chemical and volume control system.

5.4.13.3 Design Evaluation

Subsection 3.9.3 discusses the loading combinations, stress limits, and analytical methods for the structural evaluation of the reactor coolant system core makeup tank for design conditions, normal conditions, anticipated transients, and postulated accident conditions. Subsection 3.9.2 discusses the requirements for dynamic testing and analysis. The reactor coolant system design transients for normal operation, anticipated transients and postulated accident conditions are discussed in subsection 3.9.1.

Stress intensities resulting from design loads do not exceed the limits specified in ASME Code, Section III. The rules for the evaluation of the faulted conditions are defined in Appendix F of the ASME Code, Section III. Only those stress limits applicable for an elastic system analysis are used for the external load analysis.

5.4.13.4 Material Corrosion/Erosion Evaluation

Those portions of the core makeup tank in contact with reactor coolant are fabricated from or clad with stainless steel. The water chemistry of the core makeup tank, comparable to reactor coolant, causes minimal corrosion of the stainless steel. Erosion is not an issue, since there is normally no flow. A periodic analysis of the coolant chemical composition verifies that the reactor coolant quality meets the specifications, as discussed in subsection 5.2.3.

Contamination of stainless steel and nickel-chromium-iron alloys by copper, low-melting-temperature alloys, mercury, and lead is prohibited. The material selection, water chemistry specification, and residual stress in the piping minimize the potential for stress corrosion cracking, as discussed in subsection 5.2.3.

5.4.13.5 Test and Inspections

Charpy V-notch tests and drop-weight fracture toughness tests are performed as required. Orientation of test specimens is according to the ASME Code, Section III, except that the material is not considered to be subjected to high irradiation.

Compliance with the sensitization requirement is demonstrated by passing the susceptibility to intergranular attack test of ASTM A-262, Practice E, including the oxalic acid screening test according to Practice A. Inservice inspection requirements for Class 1 are discussed in Section 5.2.4.

In addition, materials and welds are inspected according to the requirements of the ASME Code, Section III Class 1.

5.4.14 Passive Residual Heat Removal Heat Exchanger

The passive residual heat removal heat exchanger (PRHR HX) is the component of the passive core cooling system that removes core decay heat for any postulated non-loss of coolant accident event where a loss of cooling capability via the steam generators occurs. Section 6.3 discusses the operation of the passive residual heat removal heat exchanger in the passive core cooling system.

5.4.14.1 Design Bases

The passive residual heat removal heat exchangers automatically removes core decay heat for an unlimited period of time, assuming the condensate from steam generated in the in-containment refueling water storage tank (IRWST) is returned to the tank. The passive residual heat removal heat exchanger is designed to withstand the design environment of 2500 psia and 650°F.

The passive residual heat removal heat exchanger and the in-containment refueling water storage tank are designed to delay significant steam release to the containment for at least one hour. The passive residual heat removal heat exchanger will keep the reactor coolant subcooled and prevent water relief from the pressurizer.

The passive residual heat removal heat exchanger in conjunction with the passive containment cooling system can remove heat for an indefinite time in a closed-loop (that is, no pipe break)

mode of operation. In addition, the passive residual heat removal heat exchanger will cool the reactor coolant system, with reactor coolant pumps operating or in the natural circulation mode, so that the reactor coolant system can be depressurized to reduce stress levels in the system if required. See Section 6.3 for a discussion of the capability of the passive core cooling system.

The passive residual heat removal heat exchanger is designed and fabricated according to the ASME Code, Section III, as a Class 1 component. Those portions of the passive residual heat exchanger that support the primary-side pressure boundary and falls under the jurisdiction of ASME Code, Section III, Subsection NF are AP1000 equipment Class A (ANS Safety Class 1, Quality Group A). Stresses for ASME Code, Section III equipment and supports are maintained within the limits of Section III of the Code. Section 5.2 provides ASME Code, Section III and material requirements. Subsection 5.2.4 discusses inservice inspection.

Materials of construction are specified to minimize corrosion/erosion and to provide compatibility with the operating environment, including the expected radiation level. Subsection 5.2.3 discusses the welding, cutting, heat treating and other processes used to minimize sensitization of stainless steel.

5.4.14.2 Design Description

The passive residual heat removal heat exchanger consists of an upper and lower tubesheet mounted through the wall of the in-containment refueling water storage tank. A series of 0.75-inch outer diameter C-shaped tubes connect the tubesheets shown in Figure 6.3-5. The primary coolant passes through the tubes, which transfer decay heat to the in-containment refueling water storage tank water and generate enough thermal driving head to maintain the flow through the heat exchanger during natural circulation. The design minimizes the diameter of the tubesheets and allows ample flow area between the tubes in the in-containment refueling water storage tank.

The horizontal lengths of the tubes and lateral support spacing in the vertical section allow for the potential temperature difference between the tubes at cold conditions and the tubes at hot conditions. The tubes are supported in the in-containment refueling water storage tank interior with a frame structure.

The passive residual heat removal heat exchanger is welded to the in-containment refueling water storage tank.

5.4.14.3 Design Evaluation

Subsection 3.9.3 discusses the loading combinations, stress limits, and analytical methods for the structural evaluation of the passive residual heat removal heat exchanger for design conditions, normal conditions, anticipated transients, and postulated accident conditions. Operation of passive residual heat removal heat exchanger is evaluated using Service Levels B, C, and D plant conditions. In addition to loads due to conditions in the reactor coolant system and operation of the passive residual heat removal heat exchanger, the passive residual heat removal heat exchanger is evaluated for hydraulic loads due to discharge of steam from the automatic depressurization system valves into a sparger in the in-containment refueling water storage tank. These loads are evaluated using Service Level B limits and are not combined with any other Service Level C or D conditions.

Seismic, loss of coolant accident, sparger activation and flow-induced vibration loads are derived using dynamic models of the passive residual heat removal heat exchanger. The dynamic analysis considers the hydraulic interaction between the coolant (steam or water) and the system structural elements.

Subsection 3.9.2 discusses the requirements for dynamic testing and analysis. Subsection 3.9.1 discusses the reactor coolant system design transients for normal operation, anticipated transients, and postulated accident conditions. In addition to reactor coolant system design transients, there are two additional Service Level B transients that affect only the passive residual heat removal heat exchanger. In the plant lifetime, there are an assumed 30 occurrences of the first transient, leakage at power. This event covers situations in which a small leak in the manway cover draws in hot reactor coolant system fluid. There are an assumed 10 occurrences in the plant lifetime of the second transient, increase in in-containment refueling water storage tank temperature, due an event which activates passive core cooling.

Stress intensities resulting from design loads do not exceed the limits specified in ASME Code, Section III. The rules evaluating the Service Level D conditions are defined in Appendix F of the ASME Code, Section III. Only those stress limits applicable for an elastic system analysis are used for the external load analysis.

During normal plant operation the system is pressurized to the reactor coolant system hot leg pressure at the temperature of the in-containment refueling water storage tank. The pressure transients during normal plant operation are the same as those for the reactor coolant system hot leg. There is no flow through the passive residual heat removal heat exchanger during normal plant operation. The tubesheet temperatures are calculated to provide sufficient temperature drop between the tubesheet and the attachment to the tank. Section 6.3 describes the passive residual heat removal heat exchanger performance characteristics.

5.4.14.4 Material Corrosion/Erosion Evaluation

Those portions of the passive residual heat removal heat exchanger in contact with reactor coolant are fabricated from or clad with corrosion-resistant material. The use of severely sensitized austenitic stainless steel in the pressure boundary of the reactor coolant system is prohibited. A periodic analysis of the coolant chemical composition verifies that the reactor coolant quality meets the specifications discussed in subsection 5.2.3.

Sulphur, lead, copper, mercury, aluminum, antimony, arsenic, and other low-melting-point elements and their alloys and compounds are restricted in their use as construction materials, erection aids, cleaning agents, and coatings for finished surfaces of the passive residual heat removal heat exchanger that are in contact with reactor coolant system fluid or in-containment refueling water storage tank. Contamination of stainless steel and nickel-chromium-iron alloys by copper, low-melting-temperature alloys, mercury, and lead is prohibited. The material selection, water chemistry specification, and residual stress in the piping minimize the potential for stress corrosion cracking, as discussed in subsection 5.2.3.

Stainless steel and nickel-chromium-iron alloys used in the passive residual heat removal heat exchanger are procured to ASME specifications.

5.4.14.5 Testing and Inspections

The passive residual heat removal heat exchanger is designed and manufactured to permit inservice inspection as specified in the ASME Code, Section XI. Methods and techniques developed for steam generator tube eddy current inspection can be used for the passive residual heat removal heat exchanger tubes.

Access for inspection and maintenance is possible through manways in the top and bottom channel heads without draining the in-containment refueling water storage tank.

The design of the passive residual heat removal heat exchanger incorporates a flexible member at the heat exchanger to in-containment refueling water storage tank interface to minimize the load imposed on the wall of the in-containment refueling water storage tank resulting from thermal expansion on the tubesheet.

Hydrostatic tests are performed in accordance with the requirements of the ASME Code, Section III, using working fluids meeting the appropriate water chemistry specifications.

5.4.15 Combined License Information

The Combined License applicant will address steam generator tube integrity with a Steam Generator Tube Surveillance Program and will address the need to develop a program for periodic monitoring of degradation of steam generator internals.

5.4.16 References

1. Eshleman, R. L., “Flexible Rotor-Bearing System Dynamics, Part I. Critical Speeds and Response of Flexible Rotor Systems,” Flexible Rotor System Subcommittee, Design Engineering Division, American Society of Mechanical Engineers, 1972.

2. Hagg, A. C. and Sankey, G. O., “The Containment of Disk Burst Fragments by Cylindrical Shells,” ASME Journal of Engineering for Power, April 1974, pp. 114-123.

3. ASTM-A-609-91, Standard Specification for Longitudinal Beam Ultrasonic Inspection of Carbon and Low-alloy Steel Castings.

4. ASTM-E-165-95, Practice for Liquid Penetrant Inspection Method.

5. ANSI/ANS-5.1-1994, “Decay Heat Power in Light Water Reactors.”

6. ANSI/ANS-51.1-1983, “Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants.”

7. ANSI N278.1-1975, Self-Operated and Power-Operated Safety-Relief Valves Functional Specification Standard.

8. QME-1, Qualification of Active Mechanical Equipment Used in Nuclear Power Plants.

9. ANSI B16.34-1996, Valves - Flanged and Buttwelding End.

10. WCAP-15994-P (Proprietary) Revision 1, and WCAP-15994-NP (Non-Proprietary) Revision 1, “Structural Analysis Summary for the AP1000 Reactor Coolant Pump High Inertia Flywheel,” March 2003.

Table 5.4-1

REACTOR COOLANT PUMP DESIGN PARAMETERS

Unit design pressure (psia)	2500
Unit design temperature (°F)	650
Unit overall height (ft-in)	21-11.5
Component cooling water flow (gpm)	600
Maximum continuous component cooling water inlet temperature (°F)	95
Total weight motor and casing, dry (lb) nominal	184,500
Pump	
Design flow (gpm)	78,750
Developed head (feet)	365
Pump discharge nozzle, inside diameter (inches)	22
Pump suction nozzle, inside diameter (inches)	26
Speed (synchronous)(rpm)	1800
Motor	
Type	Squirrel Cage Induction
Voltage (V)	6900
Phase	3
Frequency (Hz)	60
Insulation class	Class H or N
Current (amp) Starting Nominal input, cold reactor coolant	 Variable Variable
Motor/pump rotor minimum required moment of inertia (lb-ft^2)	16,500

Table 5.4-2

FLYWHEEL MATERIAL SPECIFICATION

Chemistry Requirements	
Element	**Amount (ppm)**
Molybdenum	2.0% ± 0.2%
Carbon	150 Max.
Iron	75 Max.
Silicon	75 Max.
Copper	20 Max.
Aluminum	20 Max.
Uranium	Balance
Mechanical Requirements	
Ultimate Tensile Stress	110 ksi Min.
Yield Stress	55 ksi Min.
Elongation	10% Min.
Reduction of Area	25% Min.
Charpy V-notch	10 ft-lb Min.
Heat Treatment	
Hold at 1000°C for 24 hours	
Furnace cool to room temperature at less than 100°C per hour	
Furnace vacuum atmosphere less than 10^{-4} torr	

Table 5.4-3

REACTOR COOLANT PUMP QUALITY ASSURANCE PROGRAM

	RT[a]	**UT[a]**	**PT[a]**	**MT[a]**
Castings				
Flywheel		X	X	
Casing (or pressure boundary)	X		X	
Forgings		X		X
Plate			X	
Weldments				
Circumferential	X	X	X	
Instrument connections			X	
Motor terminals[b]	X		X	

Notes:
(a) RT - radiographic, UT - ultrasonic, PT - dye penetrant, MT - magnetic particle
(b) The motor terminals are helium leak tested prior to installation.

Table 5.4-4

STEAM GENERATOR DESIGN REQUIREMENTS

Type	Vertical U-tube Feedring-type
Design pressure, reactor coolant side (psia)	2500
Design pressure, steam side (psia)	1200
Design pressure, primary to secondary (psi)	1600
Design temperature, reactor coolant side (°F)	650
Design temperature, steam side (°F)	600
S/G Power, MWt/unit	1707.5
Total heat transfer surface area (ft^2)	123,538
Steam nozzle outlet pressure, psia	836
Steam flow, lb/hr per S/G	$7.49 x 10^6$
Total steam flow, lb/hr	$14.97 x 10^6$
Maximum moisture carryover (weight percent) maximum	0.25
No load temperature, °F	557
Feedwater temperature, °F	440
Number of tubes per unit	10,025
Tube outer diameter, inch	0.688
Tube wall thickness, inch	0.040
Tube pitch, inches	0.980 (triangular)

Table 5.4-5

STEAM GENERATOR DESIGN PARAMETERS (NOMINAL VALUES)

Tube pitch, inches	0.980 (triangular)
Overall length, inches	884.26*
Upper shell I.D., inches	210
Lower shell I.D., inches	165
Tubesheet thickness, inches	31.13**
Primary water volume, ft^3	2077
Water volume in tubes, ft^3	1489
Water volume in plenums, ft^3	588
Secondary water volume, ft^3	3646
Secondary steam volume, ft^3	5222
Secondary water mass, lbm	175,758
Design fouling factor, hr-°F-ft^2/BTU	1.1x10-4

Notes:

* Measured from steam nozzle to the flat, exterior portion of the channel head.

** Base metal thickness.

Table 5.4-6

STEAM GENERATOR QUALITY ASSURANCE PROGRAM

	RT[(a)]	UT[(a)]	PT[(a)]	MT[(a)]	ET[(a)]
Base Metals					
Tubesheet Forging	 	 Yes		 Yes	
Channel Head Forging Plate Casting	 Yes	 Yes Yes 		 Yes Yes	
Secondary Shell and Head Forgings Plate		 Yes Yes		 Yes 	
Tubes		Yes			Yes
Nozzles (Forgings)		Yes		Yes	
Safe ends		Yes	Yes		
Welds					
Channel head if fabricated	Yes			Yes	
Shell, longitudinal if fabricated	Yes			Yes	
Shell, circumferential	Yes			Yes	
Primary nozzles to fabricated head	Yes			Yes	
Primary nozzles to forged head	Yes			Yes	
Manways to fabricated head or shell	Yes			Yes	
Manways to forged head or shell	Yes			Yes	
Steam and feedwater nozzles to fabricated shell	Yes			Yes	
Steam and feedwater nozzles to forged shell	Yes			Yes	
Support brackets				Yes	
Tube to tubesheet			Yes		
Instrument connections (secondary)				Yes	
Temporary attachments after removal				Yes	
After hydrostatic test (all major pressure boundary welds and complete cast channel head where accessible)				Yes	
Weld deposit on primary nozzles	Yes		Yes		
Safe end to nozzle	Yes		Yes		
Cladding					
Tubesheet		Yes[(b)]	Yes		
Channel head		Yes	Yes		
Cladding (channel head-tubesheet joint cladding restoration)		Yes	Yes		

Notes:
(a) RT – Radiographic, UT – Ultrasonic, PT – Dye penetrant, MT – Magnetic particle, ET – Eddy current.
(b) Flat surfaces only

Table 5.4-7

REACTOR COOLANT SYSTEM PIPING DESIGN

Reactor Coolant Loop Piping	
Design Pressure (psig)	2485
Design Temperature (°F)	650
Reactor Inlet Piping	
Inside Diameter (ID)	22
Nominal Wall Thickness	2.56
Reactor Outlet Piping	
Inside Diameter (ID)	31
Nominal Wall Thickness	3.25
Pressurizer Surge Line	
Design Pressure (psig)	2485
Design Temperature (°F)	680
Pressurizer Surge Line Piping	
Nominal Pipe Size	18
Nominal Wall Thickness	1.78
Pressurizer Safety Valve and ADS Valve Inlet Line	
Design Pressure (psig)	2485
Design Temperature (°F)	680
Other Rector Coolant Branch Lines	
Design Pressure (psig)	2485
Design Temperature (°F)	650

Table 5.4-8

REACTOR COOLANT SYSTEM PIPING QUALITY ASSURANCE PROGRAM

	RT[a]	**UT[a]**	**PT[a]**
Pipe (Forged Seamless)		Yes	Yes
Fittings		Yes	Yes
Weldments			
Circumferential Butt Welds	Yes		Yes
Branch Nozzle Connections	Yes[b]		Yes
Fillet Weld Instrument Connections			Yes

Notes:
(a) RT - Radiographic; UT - Ultrasonic; PT - Dye Penetrant
(b) No RT is required for branch nozzle connections of 4 inch nominal size smaller.

Table 5.4-9

PRESSURIZER DESIGN DATA

Design pressure (psig)	2485
Design temperature (°F)	680
Surge line nozzle nominal diameter (in.)	18
Spray line nozzle nominal diameter (in.)	4
Safety valve nozzle nominal diameter (in.)	14
Internal volume (ft^3)	2100

Table 5.4-10

PRESSURIZER HEATER GROUP PARAMETERS

Voltage (Vac)	480
Frequency (Hz.)	60
Power Capacity (kW)	
Control Group	370
Backup Group A	245
Backup Group B	245
Backup Group C	370
Backup Group D	370

Table 5.4-11

REACTOR COOLANT SYSTEM DESIGN PRESSURE SETTINGS

	Base Load Mode (Psig)
Hydrostatic test pressure	3106
Design pressure	2485
Safety valves (begin to open)	2485
High pressure reactor trip	2385
High pressure alarm	2310
Pressurizer spray valves (full open)	2310
Pressurizer spray valves (begin to open)	2260
Proportional heaters (begin to operate)	2250
Operating pressure	2235
Proportional heater (full operation)	2220
Backup heaters on	2210
Low pressure alarm	2210
Low pressure safeguards actuation	1870

Table 5.4-12

PRESSURIZER QUALITY ASSURANCE PROGRAM

	RT[(a)]	UT[(a)]	PT[(a)]	MT[(a)]
Heads				
Forged head		Yes		
Cladding		Yes	Yes	
Shell				
Forgings		Yes		Yes
Cladding		Yes	Yes	
Heaters				
Tubing		Yes[(b)]	Yes	
Centering of element	Yes			
Nozzle (Forgings)		Yes	Yes[(c)]	Yes[(c)]
Weldments				
Shell, circumferential	Yes			Yes
Nozzle to head (if fabricated)	Yes			Yes
Cladding		Yes	Yes	
Nozzle safe end	Yes		Yes	
Instrument nozzle			Yes	
Temporary attachments (after removal)				Yes
Boundary welds (after shop hydrostatic tests)				Yes
Support brackets				Yes

Notes:

(a) RT - Radiographic, UT - Ultrasonic, PT - Dye Penetrant, MT - Magnetic Particle.
(b) Eddy current testing can be used in lieu of UT.
(c) MT or PT.

Table 5.4-13

DESIGN BASES FOR NORMAL RESIDUAL HEAT REMOVAL SYSTEM OPERATION

RNS initiation, hours after reactor shutdown	4
RCS initial pressure (psig)	450
RCS initial temperature (°F)	350
CCS Design Temperature (°F)[(a)]	95
Cooldown time, (hours after shutdown)	96
RCS temperature at end of cooldown (°F)	125

Note:
(a) The maximum CCS temperature during cooldown is 110°F.

Table 5.4-14

NORMAL RESIDUAL HEAT REMOVAL SYSTEM COMPONENT DATA

Normal RHR Pumps (per pump)		
Minimum Flow Required for Shutdown Cooling (gpm)	1400	
Minimum Flow Required for Low Pressure Makeup (gpm)	1100	
Design Flow (gpm)	1500	
Design Head (ft)	360	
Normal RHR Heat Exchangers		
Minimum UA Required for Shutdown Cooling (BTU/hr-°F)	2.2×10^6	
Design Heat Removal Capacity (BTU/hr)[(1)]	23×10^6	
	Tube Side	**Shell Side**
Design Flow (lb/hr)	750,000	1,405,000
Inlet Temperature (°F)	125	87.5
Outlet Temperature (°F)	94	104
Fluid	Reactor Coolant	CCS

Note:
(1) Design heat removal capacity is based on decay heat at 96 hours after reactor shutdown.

Table 5.4-15

REACTOR COOLANT SYSTEM VALVE DESIGN PARAMETERS

Design pressure (psig)	2485
Preoperational plant hydrotest (psig)	3106
Design temperature (°F)	
Reactor coolant system	650
Pressurizer safety valves and ADS valves	680

Table 5.4-16

REACTOR COOLANT SYSTEM MOTOR-OPERATED VALVES DESIGN OPENING AND CLOSING PRESSURES

	Normal ΔP (PSIG)[a]		**Design ΔP (PSIG)**	
	OPEN	**CLOSE**	**OPEN**	**CLOSE**
First Stage ADS Valves (RCS-PL-V001A & B)	2235	2235[b,c]	2485	2485
First Stage ADS Isolation Valves (RCS-PL-V011A & B)	2235	2235	2485	2485
Second Stage ADS Valves (RCS-PL-V002A & B)	1200	100[b]	2485	1200
Second Stage ADS Isolation Valves (RCS-PL-V012A & B)	1200	100	2485	1200
Third Stage ADS Valves (RCS-PL-V003A & B)	500	100	2485	1200
Third Stage ADS Isolation Valves (RCS-PL-V013A & B)	500	100	2485	1200
Fourth Stage ADS Isolation Valves (RCS-PL-V014A & B)	N/A[e]	0	200[e]	200
CVS Purification Isolation Valves (CVS-PL-V001,-V002,-003)	2235	2235	2485	2485
Normal RHR Inner/Outer Isolation Valves (RNS-PL-V001A,B -V002A,B)[d]	450	450	600	600

Notes:
(a) Normal expected operating pressures.
(b) Valves are prevented from closing until ADS signal is reset.
(c) First stage ADS valve can be manually actuated for controlled depressurizations or gas venting.
(d) Valves are administratively blocked from opening at the motor control center.
(e) Fourth stage ADS block valves are normally open.

Table 5.4-17

PRESSURIZER SAFETY VALVES - DESIGN PARAMETERS

Number	2
Minimum required relieving capacity per valve (lb/hr)	750,000 at 3% accumulation
Set pressure (psig)	2485 ±25 psi
Design temperature (°F)	680
Fluid	Saturated steam
Backpressure	
Normal (psig)	3 to 5
Expected maximum during discharge (psig)	500
Environmental conditions	
Ambient temperature (°F)	50 to 120
Relative humidity (percent)	0 to 100
Residual Heat Removal Relief Valve - Design Parameters	
Number	1
Nominal relieving capacity per valve, ASME flowrate (gpm)	850
Nominal set pressure (psig)	500*
Full-open pressure, with accumulation (psig)	550*
Design temperature (°F)	400
Fluid	Reactor coolant
Backpressure	
Normal (psig)	3 to 5
Expected maximum during discharge (psig)	200
Environmental conditions	
Ambient temperature (°F)	50 to 120
Relative humidity (percent)	0 to 100

Note:
* See text (5.4.9.3) for discussion of set pressure

Table 5.4-18

REACTOR VESSEL HEAD VENT SYSTEM DESIGN PARAMETERS

System design pressure, psig	2485
System design temperature, °F	650
Number of remotely-operated valves	4
Vent line, nominal diameter, inches	1
Head vent capacity, lbm/sec (assuming a single failure, RCS pressure at 1250 psia)	8.2

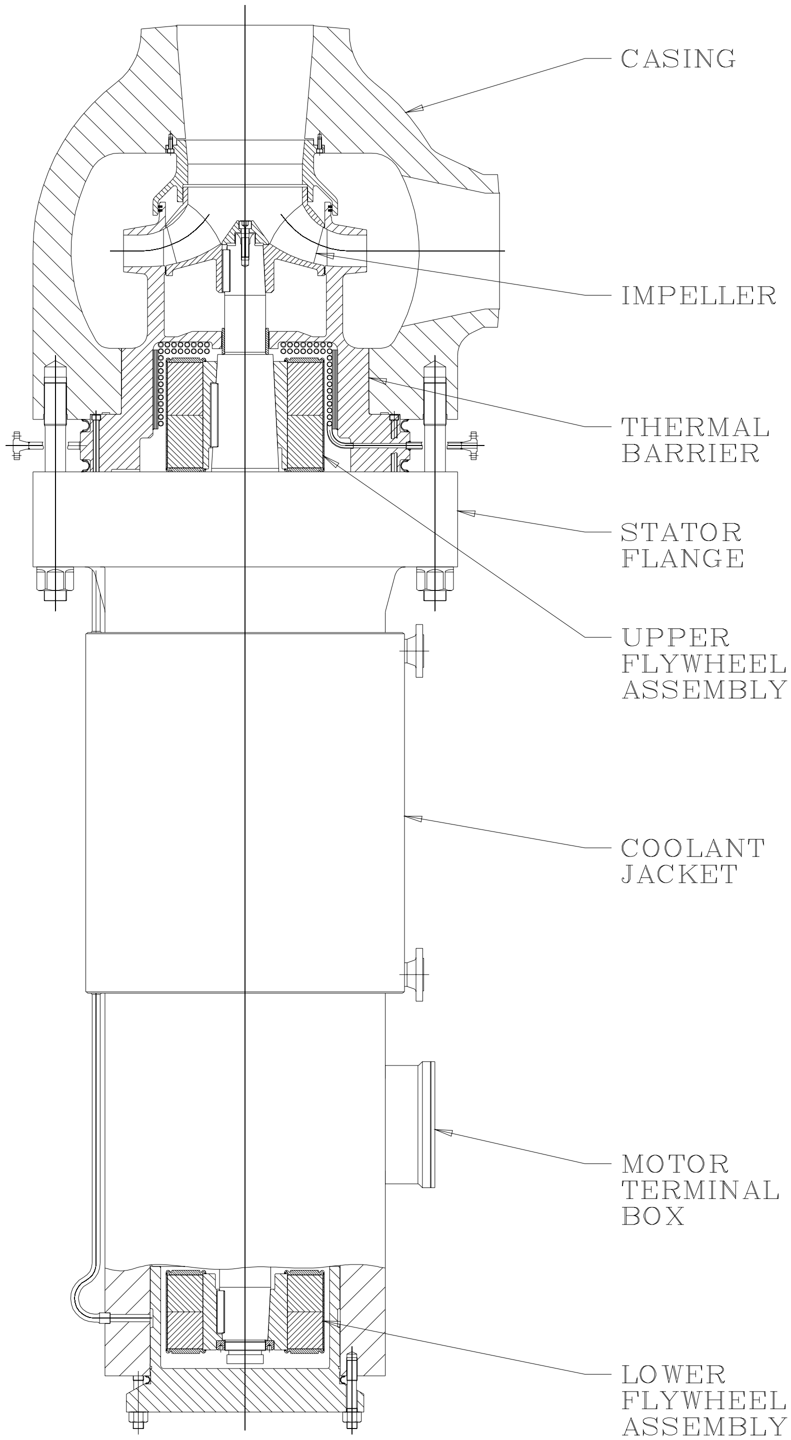


Figure 5.4-1

Reactor Coolant Pump

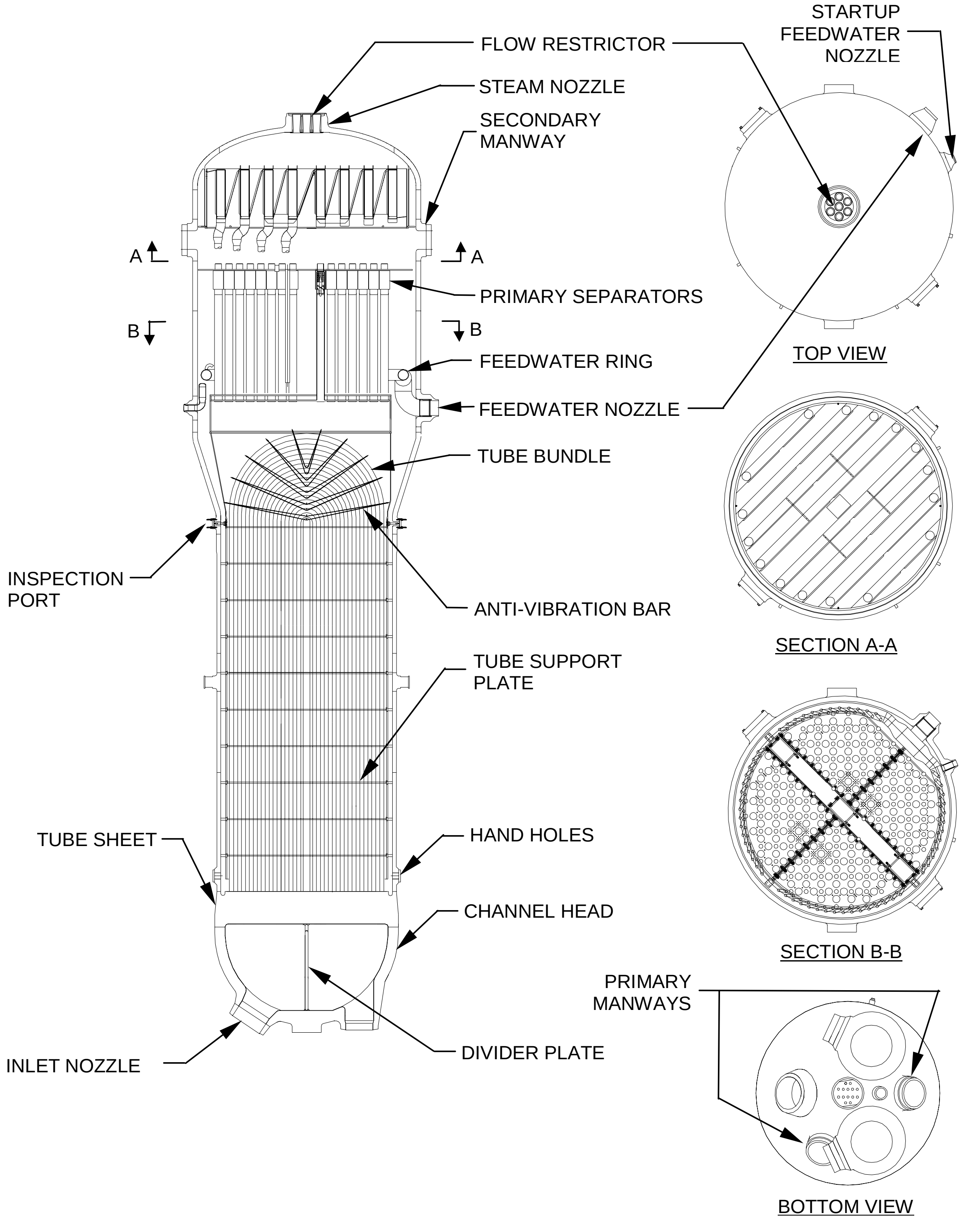


Figure 5.4-2

Steam Generator

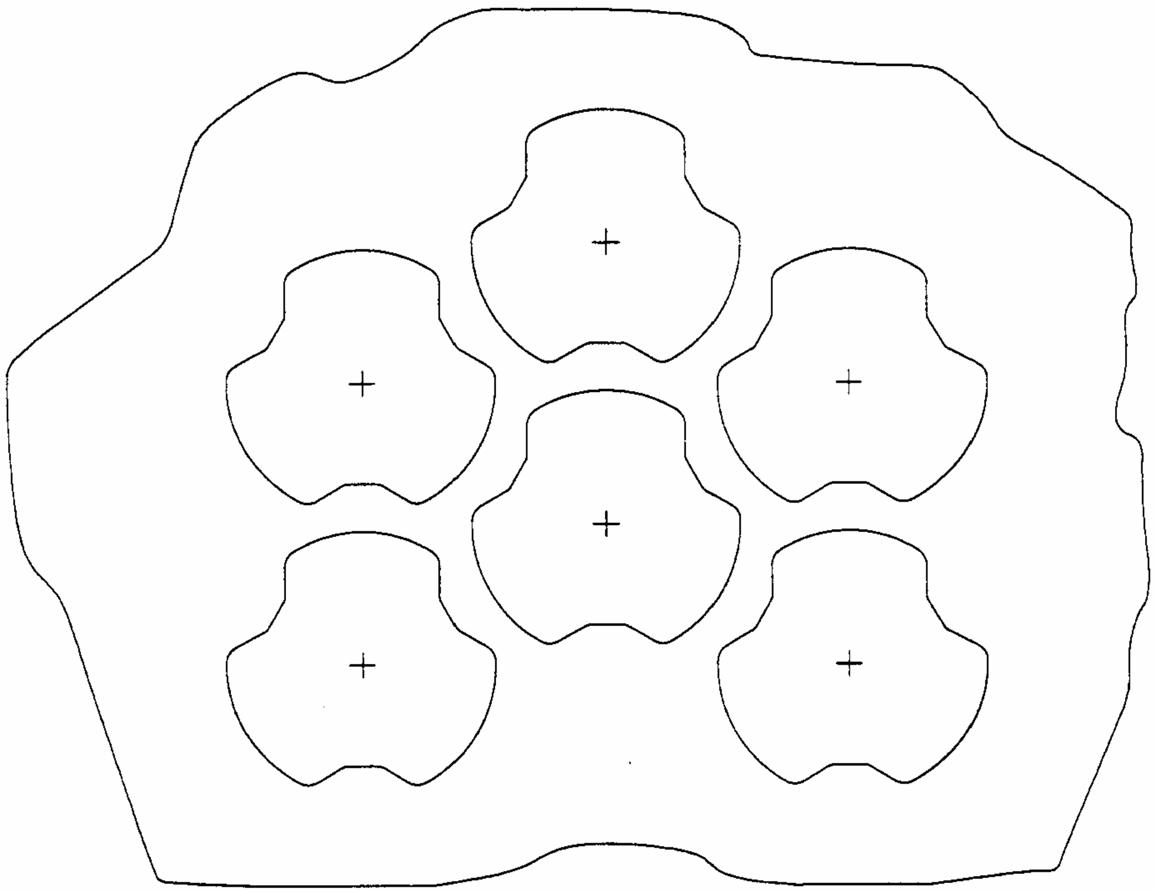


Figure 5.4-3

Support Plate Geometry
(Trifoil Holes)

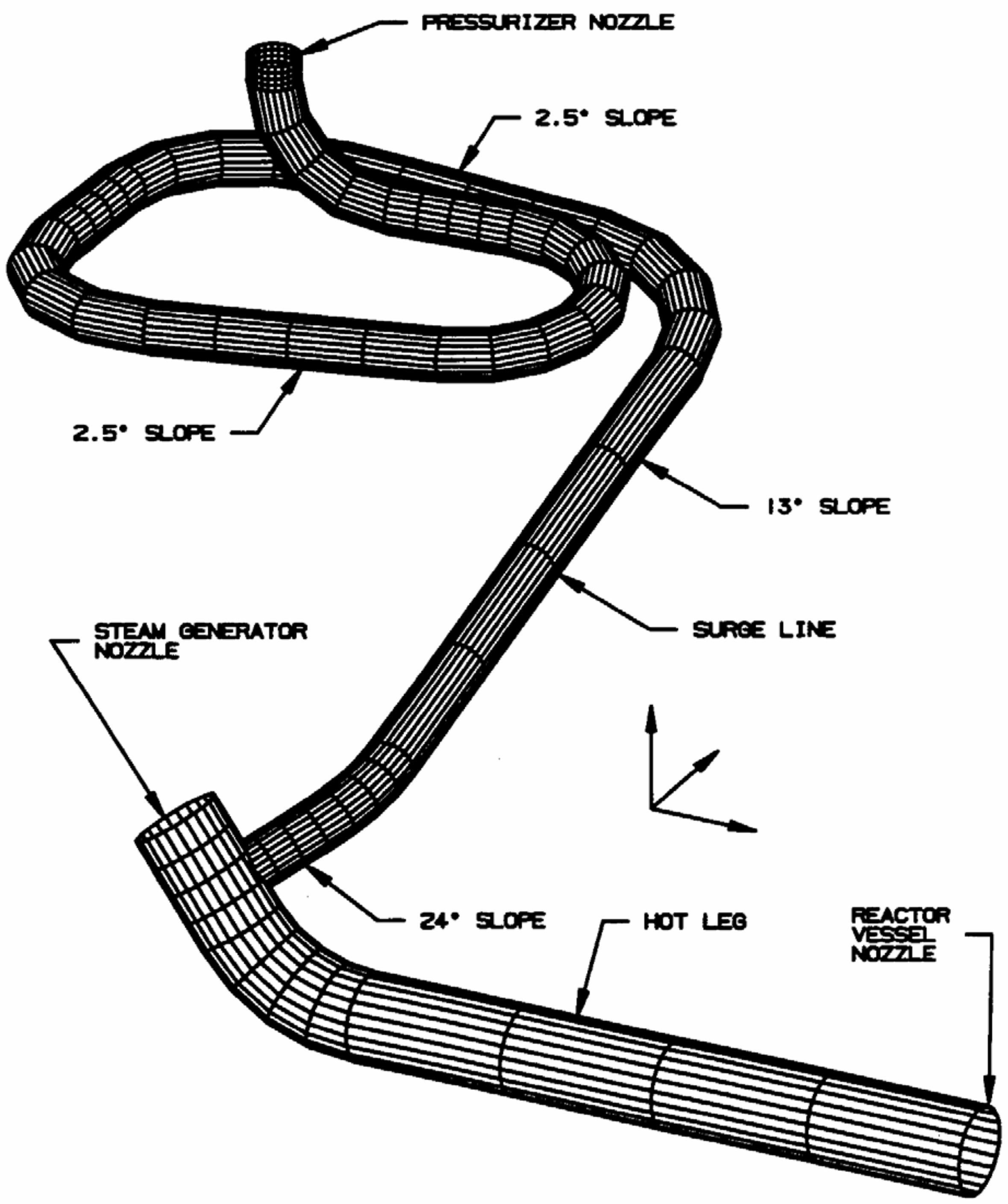


Figure 5.4-4

Surge Line

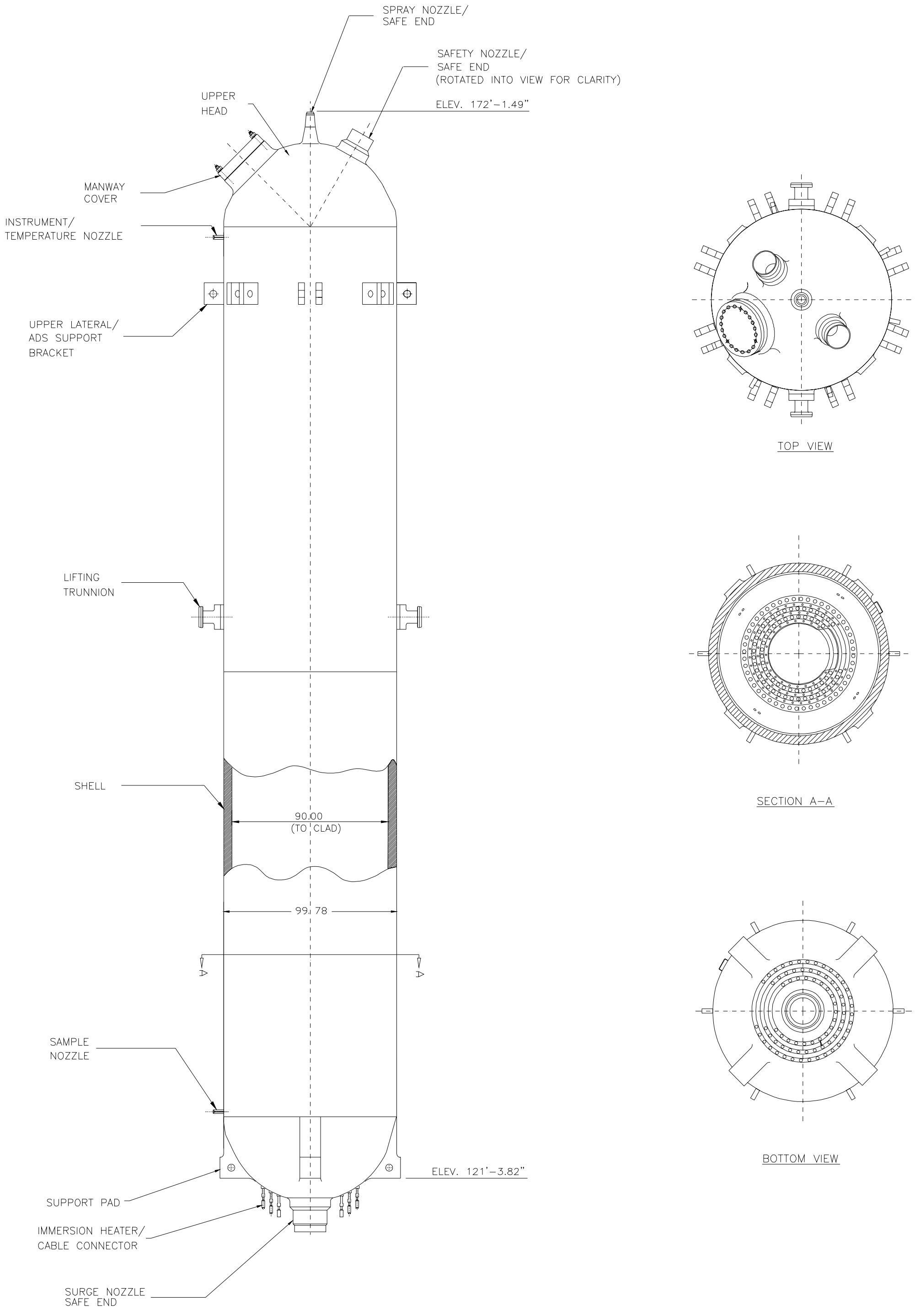


Figure 5.4-5

Pressurizer

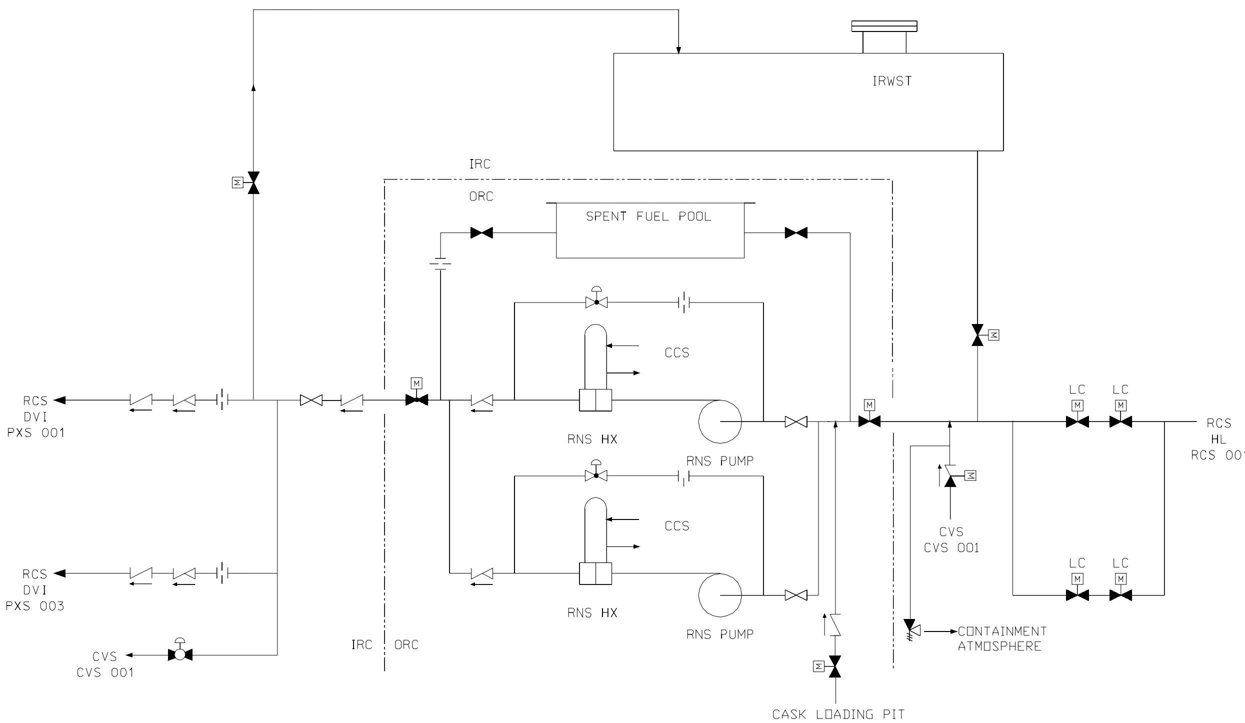
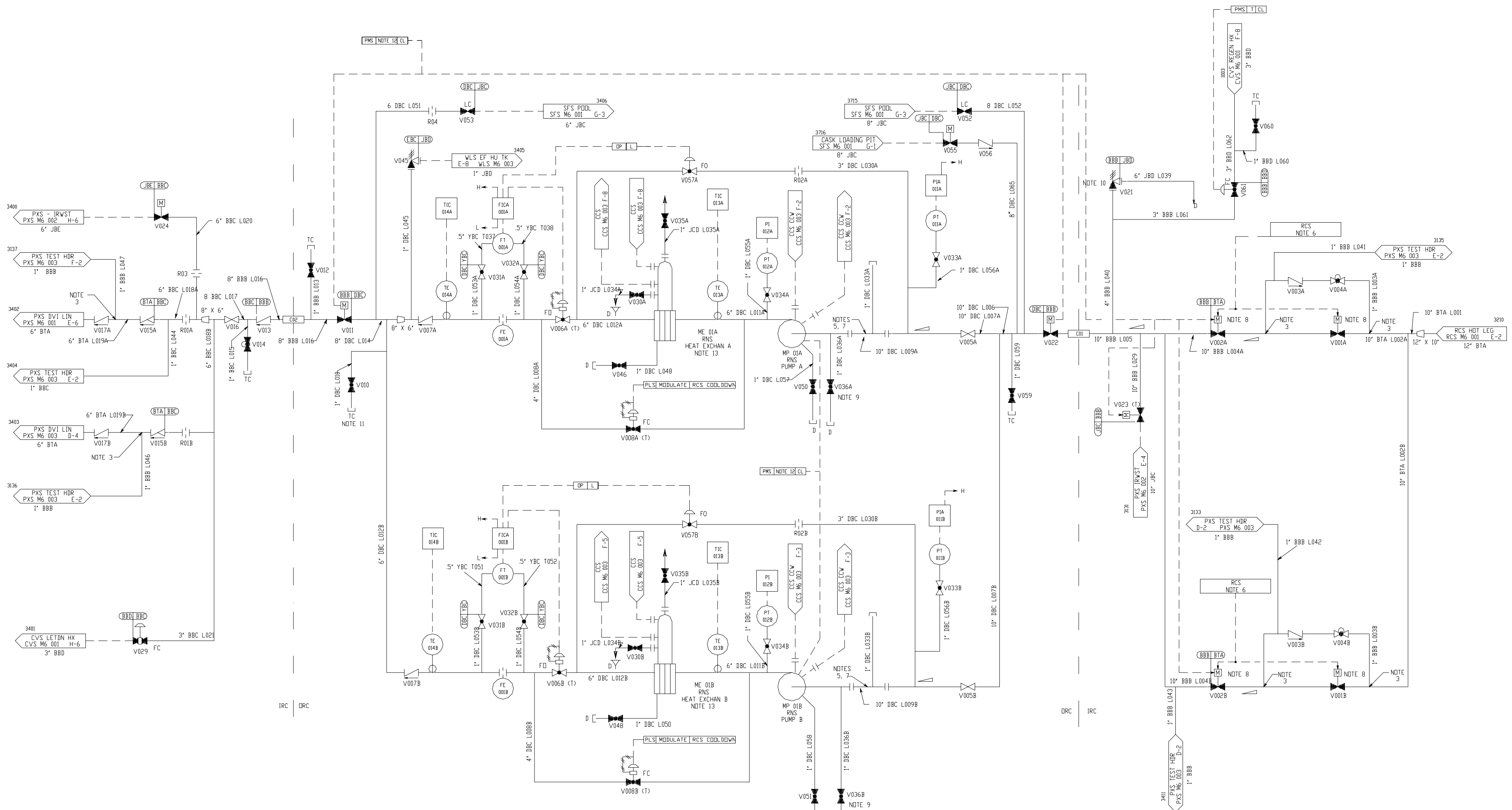


Figure 5.4-6

Normal Residual Heat Removal System

[This page intentionally blank]



NOTES:

1. THE SYSTEM LOCATOR CODE "APP-RNS" HAS BEEN OMITTED FROM ALL COMPONENT NUMBERS. THE COMPONENT CODE HAS BEEN OMITTED FROM ALL COMPONENTS EXCEPT EQUIPMENT. REFER TO THE P&ID LEGEND DRAWING APP-GW-M6-001, 002 AND 003 FOR ADDITIONAL INFORMATION REGARDING COMPONENT NUMBERING.
2. REFER TO RNS SYSTEM SPECIFICATION DOCUMENT FOR DETAILED DESCRIPTION OF INSTRUMENTATION, CONTROLS AND INTERLOCKS.
3. PROVIDE .375" ID FLOW RESTRICTOR FOR CLASS 1 AND CLASS 2 TRANSITION SIMILAR TO ARRANGEMENT SHOWN ON WESTINGHOUSE FLOW DIAGRAM LEGEND DRAWING APP-GW-M6-002 NOTE 7.
4. DRAWING NUMBERS ARE SHOWN IN INTERFACE FLAGS WITHOUT PREFIX "APP".
5. TEMPORARY STRAINER PLACED IN SPOOL PIECE FOR PRE-OPERATION FLUSHING. STRAINER AND SPOOL PIECE FURNISHED BY OTHERS. 1.00" CAPPED LINE IS CONNECTED TO PRESSURE GAGE DURING FLUSHING OPERATIONS.
6. PERMISSION TO OPEN ON RCS PRESSURE, 450 PSIG.
7. SEAL WELD FLANGES AFTER INITIAL PRE-OPERATION FLUSHING.
8. POWER TO VALVE LOCKED OUT AT THE MOTOR CONTROL CENTER.
9. LOCATE DRAIN CONNECTIONS NEAR EQUIPMENT.
10. MINIMIZE PIPE LENGTH UPSTREAM OF RELIEF VALVE.
11. LOCAL LOW POINT TO DRAIN INBOARD AND OUTBOARD CONTAINMENT ISOLATION VALVES.
12. VALVES CLOSE AND PUMPS STOP ON HIGH CONTAINMENT RADIATION, OR SAFEGUARDS ACTUATION SIGNAL.
13. POST-ACCIDENT CONTAINMENT MAKEUP IS ADDED THROUGH EITHER OF THE RNS HX CHANNEL HEAD DRAINS.

Figure 5.4-7

Normal Residual Heat Removal System Piping and Instrument Diagram

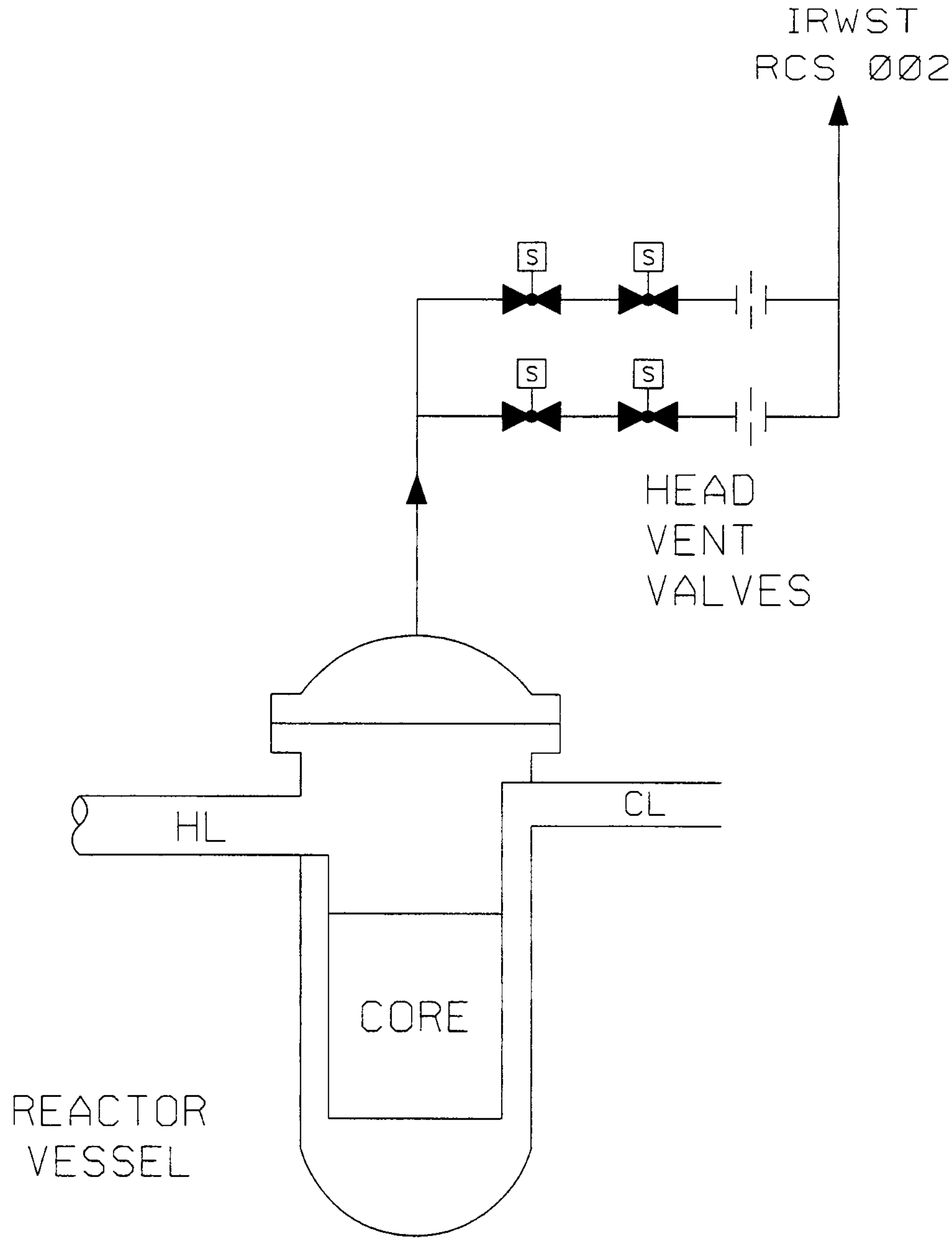


Figure 5.4-8

Reactor Vessel Head Vent System

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

LIST OF TABLES

LIST OF TABLES (Cont.)

LIST OF FIGURES

LIST OF FIGURES (Cont.)

CHAPTER 6

ENGINEERED SAFETY FEATURES

6.0 Engineered Safety Features

Engineered safety features (ESF) protect the public in the event of an accidental release of radioactive fission products from the reactor coolant system. The engineered safety features function to localize, control, mitigate, and terminate such accidents and to maintain radiation exposure levels to the public below applicable limits and guidelines, such as 10 CFR 100. The following are defined as engineered safety features:

Containment

The containment vessel, discussed in Subsection 6.2.1, is a free standing cylindrical steel vessel with ellipsoidal upper and lower heads. It is surrounded by a Seismic Category I reinforced concrete shield building. The function of the containment vessel, as part of the overall containment system, is to contain the release of radioactivity following postulated design basis accidents. The containment vessel also functions as the safety-related ultimate heat sink by transferring the heat associated with accident sources to the surrounding environment. The following paragraph details this safety-related feature.

Passive Containment Cooling System

The function of the passive containment cooling system, discussed in Subsection 6.2.2, is to maintain the temperature below a maximum value and to reduce the containment temperature and pressure following a postulated design-basis event. The passive containment cooling system removes thermal energy from the containment atmosphere. The passive containment cooling system also serves as the safety-related ultimate heat sink for other design basis events and shutdowns. The passive containment cooling system limits the release of radioactive material to the environment by reducing the pressure differential between the containment atmosphere and the external environment. This diminishes the driving force for leakage of fission products from the containment to the atmosphere.

Containment Isolation System

The major function of the containment isolation system of the AP1000, discussed in Subsection 6.2.3, is to provide containment isolation to allow the normal or emergency passage of fluids through the containment boundary while preserving the integrity of the containment boundary, if required. This prevents or limits the escape of fission products that may result from postulated accidents. Containment isolation provisions are designed so that fluid lines penetrating the primary containment boundary are isolated in the event of an accident. This minimizes the release of radioactivity to the environment.

Passive Core Cooling System

The primary function of the passive core cooling system, discussed in Section 6.3, is to provide emergency core cooling following postulated design-basis events. The passive core cooling system

provides reactor coolant system makeup and boration during transients or accidents where the normal reactor coolant system makeup supply from the chemical and volume control system is lost or is insufficient. The passive core cooling system provides safety injection to the reactor coolant system to provide adequate core cooling for the complete range of loss of coolant accident events up to, and including, the double ended rupture of the largest primary loop reactor coolant system piping. The passive core cooling system provides core decay heat removal during transients, accidents, or whenever the normal heat removal paths are lost.

Main Control Room Emergency Habitability System

The main control room emergency habitability system, discussed in Section 6.4, is designed so that the main control room remains habitable following a postulated design basis event. With a loss of all ac power sources, the habitability system will maintain an acceptable environment for continued operating staff occupancy.

Fission Product Control

Post-accident safety-related fission product control for the AP1000, discussed in Section 6.5, is provided by natural removal processes inside containment, the containment boundary, and the containment isolation system. The natural removal processes, including various aerosol removal processes and pool scrubbing, remove airborne particulates and elemental iodine from the containment atmosphere following a postulated design basis event.

6.1 Engineered Safety Features Materials

This section provides a description of the materials used in the fabrication of engineered safety features components and of the provisions to avoid material interactions that could potentially impair the operation of the engineered safety features. A list of engineered safety features was given previously in Section 6.0. Reactor coolant system materials, including branch piping connected to the reactor coolant system, are described in subsection 5.2.3.

6.1.1 Metallic Materials

Materials for use in engineered safety features are selected for their compatibility with the reactor coolant system and refueling water.

The edition and addenda of the ASME Code applied in the design and manufacture of each component are the edition and addenda established by the requirements of the Design Certification. The use of editions and addenda issued subsequent to the Design Certification is permitted or required based on the provisions in the Design Certification. The baseline used for the evaluations done to support this safety analysis report and the Design Certification is the 1998 Edition, through the 2000 Addenda. When material is procured to later editions or addenda, the design of the component is reconciled to the new material properties in accordance with the rules of the ASME Code, provided that the later edition and addenda are authorized in 10 CFR 50.55a or in a specific authorization as provided in 50.55a(a)(3).

6.1.1.1 Specifications for Principal Pressure-Retaining Materials

The pressure-retaining materials in engineered safety features system components comply with the corresponding material specification permitted by the ASME Code, Section III, Division 1. The material specifications used for pressure-retaining valves in contact with reactor coolant are the specifications used for reactor coolant pressure boundary valves and piping. See Table 5.2-1 for a listing of these specifications. The material specifications for pressure-retaining materials in each component of an engineered safety features system meet the requirements of Article NC-2000 of the ASME Code, Section III, Class 2, for Quality Group B; Article ND-2000 of the ASME Code, Section III, Class 3, for Quality Group C components; and Article NE-2000 of the ASME Code, Section III for containment pressure boundary components.

Containment penetration materials meet the requirements of Articles NC-2000 or NE-2000 of the ASME Code, Section III, Division 1. The quality groups assigned to each component are given in Section 3.2. The pressure-retaining materials are indicated in Table 6.1-1. Materials for ASME Class 1 equipment are provided in subsection 5.2.3.

The following subsection provides information on the selection and fabrication of the materials in the engineered safety features of the plant.

Components in contact with borated water are fabricated of, or clad with, austenitic stainless steel or equivalent corrosion-resistant material. The use of nickel-chromium-iron alloy in the engineered safety features is limited to Alloy 690 or its associated weld metals Alloys 52 and 152. Nickel-chromium-iron alloy is used where the corrosion resistance of the alloy is an important

consideration and where the use of nickel-chromium-iron alloy is the choice because of the coefficient of thermal expansion.

The material for the air storage tanks in the main control room emergency habitability system is tested for Charpy V-Notch per supplement S3 of material specification SA-372 and has an average of 20 to 25 mills of lateral expansion at the lowest anticipated service temperature. The material is not permitted to be weld repaired.

6.1.1.2 Fabrication Requirements

The welding materials used for joining the ferritic base materials of the pressure-retaining portions of the engineered safety features conform to, or are equivalent to, ASME Material Specifications SFA 5.1, 5.2, 5.5, 5.17, 5.18, and 5.20. 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.

The welding materials used for joining the austenitic stainless steel base materials for the pressure-retaining portions of engineered safety features conform to, or are equivalent to, ASME Material Specifications SFA 5.4 and 5.9. These materials are qualified to the requirements of the ASME Code, Section III and Section IX, and are used in procedures qualified to these same rules. The methods used to control delta ferrite content in austenitic stainless steel weldments in engineered safety features components are the same as those for ASME Code Class 1 components, described in subsection 5.2.3.4.

The integrity of the safety-related components of the engineered safety features is maintained during component manufacture. Austenitic stainless steel is used in the final heat-treated condition as required by the respective ASME Code, Section II, material specification for the particular type or grade of alloy. Also, austenitic stainless steel materials used in the engineered safety features components are handled, protected, stored, and cleaned according to recognized and accepted methods designed to minimize contamination, which could lead to stress corrosion cracking. These controls for engineered safety features components are the same as those for ASME Code Class 1 components, discussed in subsection 5.2.3.4. Sensitization avoidance, intergranular attack prevention, and control of cold work for engineered safety features components are the same as the ASME Code Class 1 components discussed in subsection 5.2.3.4. Cold-worked austenitic stainless steels having a minimum specified yield strength greater than 90,000 psi are not used for components of the engineered safety features.

Information is provided in Section 1.9 concerning the degree of conformance with the following Regulatory Guides:

- Regulatory Guide 1.31, Control of Ferrite Content in Stainless Steel Weld Metal
- Regulatory Guide 1.44, Control of the Use of Sensitized Stainless Steel

Lead, antimony, cadmium, indium, mercury, zinc, and tin metals and their alloys are not allowed to come in contact with engineered safety features component parts made of stainless steel or high alloy metals during fabrication or operation. Bearing alloys containing greater than 1 percent of lead, antimony, cadmium, or indium are not used in contact with reactor coolant.

6.1.1.3 Specifications for Nonpressure-Retaining Materials

Materials for nonpressure-retaining portions of engineered safety features in contact with borated water or other fluids may be procured under ASTM designation. The principle examples of these items are the in-containment refueling water storage tank liner and the passive containment cooling system storage tank liner.

The walls of the in-containment refueling water storage tank may be fabricated of ASTM A240 Type XM-29. This is a nitrogen-strengthened austenitic stainless steel with higher ultimate tensile and yield strengths than type 304 and 316 stainless steel. This material can be welded using E240 filler metal by either the shielded metal arc welding or gas tungsten arc welding methods. This material is used for applications where the higher strength allows reductions in weight and material costs. The material has a resistance to intergranular stress corrosion cracking similar to or better than type 304 and 304L stainless steel.

6.1.1.4 Material Compatibility with Reactor Coolant System Coolant and Engineered Safety Features Fluids

Engineered safety features components materials are manufactured primarily of stainless steel or other corrosion-resistant material. Protective coatings are applied on carbon steel structures and equipment located inside the containment, as discussed in subsection 6.1.2.

Austenitic stainless steel plate conforms to ASME SA-240. Austenitic stainless steel is confined to those areas or components which are not subject to post-weld heat treatment. Carbon steel forgings conform to ASME SA-350. Austenitic stainless steel forgings conform to ASME SA-182. Nickel-chromium-iron alloy pipe conforms to ASME SB-167. Carbon steel castings conform to ASME SA-352. Austenitic stainless steel castings conform to ASME SA-351.

Hardfacing material in contact with reactor coolant is a qualified low- or zero-cobalt alloy, equivalent to Stellite-6. The use of cobalt-base alloys is minimized. Low- or zero-cobalt alloys used for hardfacing or other applications where cobalt-base alloys have been previously used are qualified by wear and corrosion tests. The corrosion tests qualify the corrosion resistance of the alloy in reactor coolant. Cobalt-free, wear-resistant alloys considered for this application include those developed and qualified in nuclear industry programs.

In post-accident situations where the containment is flooded with water containing boric acid, pH adjustment is provided by the release of trisodium phosphate into the water. The trisodium phosphate is held in baskets located in the floodable volume that includes the steam generator compartments and contains the reactor coolant loop. The addition of trisodium phosphate to the solution is sufficient to raise the pH of the fluid to above 7.0. This pH is consistent with the guidance of NRC Branch Technical Position MTEB-6.1 for the protection of austenitic stainless steel from chloride-induced stress corrosion cracking. Section 6.3 describes the design of the trisodium phosphate baskets.

In the post-accident environment, both aluminum and zinc surfaces in the containment are subject to chemical attack resulting in the production of hydrogen. The non-flooded surfaces would be wetted by condensing steam but they would not be subjected to the boric acid or trisodium

phosphate solutions since there is no containment spray. Nonsafety-related passive autocatalytic recombiners are provided to limit hydrogen buildup inside containment.

6.1.1.5 Integrity of Safety-Related Components

The pH adjustment baskets provide for long-term pH control. In the case of inadvertent short-term flooding when the pH adjustment baskets remain above the flood level, the condition of the material in contact with the fluid is evaluated prior to return to operation. Based on previous industry testing and experience, the behavior of austenitic stainless steels in the post-design basis accident environment is acceptable. Cracking is not anticipated, provided that the core cooling pH is maintained at an adequate level.

6.1.1.6 Thermal Insulation

The majority of the engineered safety features insulation used in the AP1000 containment is reflective metallic insulation. Fibrous insulation may be used if it is enclosed in stainless steel cans. The selection, procurement, testing, storage, and installation of nonmetallic thermal insulation provides confidence that the leachable concentrations of chloride, fluoride, and silicate are in conformance with Regulatory Guide 1.36. Conformance with Regulatory Guide 1.36 is summarized in Section 1.9.

6.1.1.7 Component and System Cleaning

See subsection 1.9.1 for a discussion on the provisions of Regulatory Guide 1.37 for the cleaning of components and systems.

6.1.2 Organic Materials

6.1.2.1 Protective Coatings

6.1.2.1.1 General

The AP1000 is divided into four areas with respect to the use of protective coatings. These four areas are:

- Inside containment
- Exterior surfaces of the containment vessel
- Radiologically controlled areas outside containment
- Remainder of plant.

The considerations for protective coatings differ for these four areas and the coatings selection process accounts for these differing considerations. The AP1000 design considers the function of the coatings, their potential failure modes, and their requirements for maintenance. Table 6.1-2 lists different areas and surfaces inside containment and on the containment shell that have coatings, their functions, and to what extent their coatings are related to plant safety.

Coatings used outside containment do not provide functions related to plant safety except for the coating on the outside of the containment shell. The coating on the outside of the containment

above elevation 135′ 3″ shell supports passive containment cooling system heat transfer and is classified as a Service Level III coating.

The coating used on the inside surface of the containment shell, greater than 7′ above the operating deck, supports the transfer of thermal energy from the post-accident atmosphere inside containment to the containment shell. Passive containment cooling system testing and analysis have been performed with a coating. This coating is classified as a Service Level I coating.

Coatings are not used in the vicinity of the containment recirculation screens to minimize the possibility of debris clogging the screens. Subsection 6.3.2.2.7.3 defines the area in the vicinity of the recirculation screens where coatings are not used.

Coatings used inside containment, except for the containment shell, are classified as Service Level II coatings because their failure does not prevent functioning of the engineered safety features. If the Service Level II coatings delaminate, the solid debris they may form will not have a negative impact on the performance of safety-related post-accident cooling systems. See subsection 6.1.2.1.5 for a discussion of the factors including plant design features and low water flows that permit the use of Service Level II coatings inside containment. Protective coatings are maintained to provide corrosion protection for the containment pressure boundary and for other system components inside containment.

The corrosion protection of the containment shell is a safety-related function. Good housekeeping and decontamination functions of the coatings are nonsafety-related functions.

For information on coating design features, quality assurance, material and application requirements, and performance monitoring requirements, see subsection 6.1.2.1.6.

6.1.2.1.2 Inside Containment

Carbon Steel

Inorganic zinc primer is the basic coating applied to the containment vessel and structural carbon steel that need coating. Below the operating floor, most of the inorganic zinc primer is top coated with epoxy where enhanced decontamination is desired. The epoxy top coat also extends above the operating floor on structural modules and to a wainscot height of 7 feet above the operating floor on the containment vessel. Where practical, miscellaneous carbon steel items (such as stairs, ceilings, gratings, ladders, railings, conduit, duct, and cable tray) are hot-dip galvanized. Steel surfaces subject to immersion during normal plant operation (such as sumps and gutters) are stainless steel or are coated with epoxy or epoxy phenolic applied directly to the carbon steel without an inorganic zinc primer. Carbon steel structures and equipment are assembled in modules and the modules are coated in the fabrication shop under controlled conditions.

Concrete

Concrete surfaces inside containment are coated primarily to prevent concrete from dusting, to protect it from chemical attack and to enhance decontaminability. In keeping with ALARA goals, the exposed concrete surfaces are made as decontaminable as practical in areas of frequent personnel access and areas subject to liquid spray, splash, spillage or immersion.

Exposed concrete surfaces inside containment are coated with an epoxy sealer to help bind the concrete surface together and reduce dust that can become contaminated and airborne. Concrete floors inside containment are coated with a self-leveling epoxy. Exposed concrete walls inside containment are coated to a minimum height of 7 feet with an epoxy applied over an epoxy surfacer that has been struck flush.

6.1.2.1.3 Exterior of Containment Vessel

The exterior of the containment vessel is coated with the same inorganic zinc as is used inside of the containment. The inorganic zinc coating enhances heat transfer by providing good heat conduction and by enhancing surface wetting of the exterior surface of the containment vessel. The inorganic zinc also provides corrosion protection.

6.1.2.1.4 Radiologically Controlled Areas Outside Containment and Remainder of Plant

The coatings used in the radiologically controlled areas outside containment and in the remainder of the plant are also classified as Service Level II coatings. However, these coatings are selected, specified, and applied in a manner that optimizes performance and standardization within the AP1000 design. Therefore, wherever practical, the same coating systems are used in radiologically controlled areas outside containment as are used inside containment. The ALARA concept is carried through in areas subject to radiation exposure and possible radiological contamination. The remainder of the plant coating systems are commercial grade materials that are selected and applied according to the expected conditions in the specific areas where the coatings are applied.

The coatings used in radiologically controlled areas outside of containment are identified in the following.

Carbon Steel Surfaces

Carbon steel is coated with inorganic zinc. An epoxy top coat is used in areas subject to decontamination such as a 7 foot wainscot in high traffic areas or on surfaces subject to radiologically contaminated liquid spray, splash, or spills.

Concrete Floors

Floors subject to heavy traffic or contaminated liquid spills are coated with self-leveling epoxy. An epoxy top coat is applied a minimum of 1 foot up the wall where liquid spills might splash. Floors subject to light traffic and not subject to contaminated liquid spills are coated with an epoxy top coat. The epoxys applied to the concrete surfaces are the same epoxy used as a top coat for the inorganic zinc-coated steel.

Concrete Walls

A 7-foot wainscot on exposed concrete walls in high-traffic areas and any surfaces of walls subject to spray, splash or spills of contaminated liquids are coated with epoxy top coat applied over an epoxy surfacer that has been struck flush. The epoxys used on concrete surfaces are the same as that used as a top coat for the inorganic zinc-coated steel. Remaining concrete walls are coated with an epoxy sealer to reduce or eliminate dusting.

Concrete Ceilings

Exposed concrete ceilings are coated with an epoxy sealer to reduce dusting.

6.1.2.1.5 Safety Evaluation

This subsection describes the basis for classifying coatings as Service Level I, II, or III. Table 6.1-2 identifies which coatings are classified as Service Level I and Service Level III.

The inorganic zinc coating on the outside of the containment shell above elevation 135′ 3″ supports passive containment cooling system heat transfer and is classified as a Service Level III coating.

The inorganic zinc coating used on the inside surface of the containment shell, greater than 7′ above the operating deck, supports the transfer of thermal energy from the post-accident atmosphere inside containment to the containment shell. Passive containment cooling system testing and analysis have been performed with an inorganic zinc coating. This coating is classified as Service Level I coating.

The AP1000 has a number of design features that facilitate the use of Service Level II coatings inside containment. These features include a passive safety injection system that provides a long delay time between a LOCA and the time recirculation starts. This time delay provides time for settling of debris. These passive systems also flood the containment to a high level which allows the use of containment recirculation screens that are located well above the floor and are relatively tall. Significant volume is provided for the accumulation of coating debris without affecting screen plugging. These screens are protected by plates located above the screens that extend out in front and to the side of the screens. Coatings are not used under these plates in the vicinity of the screens. The protective plates, together with low recirculation flow, approach velocity and the screen size preclude postulated coating debris above the plates from reaching the screens. Refer to subsection 6.3.2.2.7.3 for additional discussion of these screens, their protective plates and the areas where coatings are prohibited from being used.

The recirculation inlets are screened enclosures located near the northwest and southwest corners of the east steam generator compartment (refer to the figures in Section 6.3.2.2.7.3). The enclosure bottoms are located above the surrounding floor which prevent ingress of heavy debris (specific gravity greater than 1.05). Additionally, the screens are oriented vertically and are protected by large plates located above the screens, further enhancing the capability of the screens to function with debris in the water. The screen mesh size and the surface area of the containment recirculation screens in the AP1000, in conjunction with the large floor area for debris to settle on, can accommodate failure of coatings inside containment during a design basis accident even though the residue of such a failure is unlikely to be transported to the vicinity of the enclosures.

The AP1000 does not have a safety-related containment spray system. The containment spray system provided in the AP1000 is only used for beyond design basis events. This reduces the chance that coatings will peel off surfaces inside containment because the thermal shock of cold spray water on hot surfaces combined with the rapid depressurization following spray initiation are recognized as contributors to coating failure. Parts of the containment below elevation 110′ are

flooded and water is recirculated through the passive core cooling system. However, the volume of water moved in this manner is relatively small and the flow velocity is very low.

The coating systems used inside containment also include epoxy coatings. These are applied to concrete substrates, as top coats over the inorganic zinc primer, and directly to steel, as noted in subsection 6.1.2.1.2. The failure modes of these systems could include delamination or peeling if the epoxy coatings are not properly applied (References 1, 2, 3). The epoxys applied to concrete and carbon steel surfaces are sufficiently heavy (dry film density greater than 100 lb/ft^3) so that transport with the low water velocity in the AP1000 containment is limited.

Inside containment, there are engineered components coated with various manufacturer's standard coating systems which are also classified as Service Level II and may peel or delaminate under design basis accident conditions. The density of these coatings is not limited based on the following considerations:

– The total surface area of low density coatings applied to engineered components is a small percentage of the total area of coatings inside containment.

– The coatings applied to engineered components are less subject to failure during accidents because their dimensions are smaller and their shapes are more complex. Their shapes are complex involving many corners, angles, nuts, bolts, protrusions, holes, etc. For engineered components, temperature changes cause smaller relative expansions and their complex shapes tend to prevent relative movement so that failure of the coating bond is less likely. In addition, even if the coating bond does fail, it is less likely to detach because the complex shapes tend to retain the coating.

– Coatings applied to engineered components are done so in controlled factory conditions so that the quality of application is better than that achieved in the field. Factors contributing to this higher quality include application of coatings in a timely fashion after manufacture, easier control of surface conditions, automated application of coatings and use of personnel that are highly trained.

– Manufacturers have switched to the use of dry powder coatings (polyesters) and water reduced coatings (acrylics). Coatings used on components located inside containment are expected to be dry powder coatings because water reduced coatings are not suitable for use in the harsh containment environment. Dry powder coatings tend to be very tough and defects in application tend to be noticeable. They also have relatively high densities, greater than epoxys, so that even if they did fail they would settle out before reaching the recirculation screens.

– Engineered components are located throughout the containment so that the majority are located where low density coating debris settle out well away from the recirculation screens.

– Even in the unlikely event that some of these coatings fail, delaminate and do not settle out because of their location and low density, the PXS recirculation screens will prevent blockage of the PXS recirculation flow path.

Requirements related to production of hydrogen as a result of zinc corrosion in design basis accident conditions, including the zinc in paints applied inside containment, were eliminated by the final rule, effective October 16, 2003, amending 10 CFR 50.44, "Standards for Combustible Gas Control System in Light-Water-Cooled Power Reactors."

6.1.2.1.6 Quality Assurance Features

A number of quality assurance features provide confidence that the coating systems inside the containment, on the exterior of the containment vessel and in potentially contaminated areas outside containment will perform as intended. These features enhance the ALARA program and enhance corrosion resistance. The features are discussed in the following paragraphs.

Service Level I and Service Level III Coatings

The quality assurance program for Service Level I and Service Level III coatings conforms to the requirements of ASME NQA-1-1983 as endorsed in Regulatory Guide 1.28. Safety related coatings meet the pertinent provisions of 10CFR Part 50 Appendix B to 10CFR Part 50. The service level classification of coatings is consistent with the positions given in Revision 1 of Regulatory Guide 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants." Service Level I and Service Level III coatings used in the AP1000 are tested for radiation tolerance and for performance under design basis accident conditions. Where decontaminability is desired, the coatings are evaluated for decontaminability. The coating applicator submits and follows acceptable procedures to control surface preparation, application of coatings and inspection of coatings. The painters are qualified and certified, and the inspectors are qualified and certified.

The inorganic zinc coating used on the inside surface (Service Level I coatings) and outside surface (Service Level III coatings) of the containment shell is inspected using a non-destructive dry film thickness test and a MEK rub test. These inspections are performed after the initial application and after recoating. Long term surveillance of the coating is provided by visual inspections performed during refueling outages. Other inspections are not required.

The procurement, application, and monitoring of Service Level I and Service Level III coatings are controlled by a program prepared by the Combined License applicant (refer to subsection 6.1.3.2).

Refer to Table 6.1-2 for identification of Service Level I and Service Level III coating applications in the AP1000.

Service Level II Coatings

The use of Service Level II coatings inside containment is based on the use of selected types of coatings and the properties of the coatings. To preclude the use of inappropriate coatings, the procurement of Service Level II coatings used inside containment is considered safety-related activity.

Appendix B to 10 CFR Part 50 applies to procurement of Service Level II coatings used inside containment on internal structures, including walls, floor slabs, structural steel, and the polar crane, except for such surfaces located inside the chemical and volume control system room # 11209. Service Level II coatings used in the chemical and volume control system room are not subject to procurement under 10 CFR 50, Appendix B, because the room is connected to the containment in a limited way through a drain line. In addition, the drain line is routed to the waste liquid processing system sump which is located well below and separate from the recirculation screens. The specified Service Level II coatings used inside containment are tested for radiation tolerance and for performance under design basis accident conditions. Where decontaminability is desired, the coatings are evaluated for decontaminability.

The Service Level II coatings used inside containment are as shown in Table 6.1-2. The application, inspection, and monitoring of Service Level II coatings are controlled by a program prepared by the Combined License applicant. This program is not subject to 10 CFR 50, Appendix B, quality assurance requirements.

Due to the use of modularized construction, a significant portion of the containment coatings are shop applied to the containment vessel and to piping, structural and equipment modules. This application of coatings under controlled shop conditions provides additional confidence that the coatings will perform as designed and as expected.

The coatings used in radiologically controlled areas outside containment are tested for radiation resistance and evaluated for decontaminability; they are not specified to be design basis accident tested. Where practical, the same coating materials are used in radiologically controlled areas outside containment as are used inside containment. This provides a high level of quality and optimizes maintenance painting over the life of the plant.

6.1.2.2 Other Organic Materials

A listing of other organic materials in the containment is developed based on the specific type of equipment and the supplier selected to provide it. Materials are evaluated for potential interaction with engineered safety features to provide confidence that the performance of the engineered safety features is not unacceptably affected.

6.1.3 Combined License Information Items

6.1.3.1 Procedure Review

The Combined License applicants referencing the AP1000 will address review of vendor fabrication and welding procedures or other quality assurance methods to judge conformance of austenitic stainless steels with Regulatory Guides 1.31 and 1.44.

6.1.3.2 Coating Program

The Combined License applicants referencing the AP1000 will provide a program to control procurement, application, and monitoring of Service Level I and Service Level III coatings. The program for the control of the use of these coatings will be consistent with subsection 6.1.2.1.6.

6.1.4 References

1. NUREG-0797, "Safety Evaluation Report related to the operation of Comanche Peak Steam Electric Station, Units 1 and 2."

2. Bolt, R. O. and J. G. Carroll, "Radiation Effects on Organic Materials," Academic Press, New York, 1963, Chapter 12.

3. Parkinson, W. W. and O. Sisman, "The Use of Plastics and Elastomers in Nuclear Radiation," Nuclear Engineering and Design 17 (1971), pp 247-280, North-Holland Publishing Co., Amsterdam.

Table 6.1-1

ENGINEERED SAFETY FEATURES PRESSURE-RETAINING MATERIALS

Component	**Materials**
Core makeup tank	Refer to subsection 5.2.3
Passive residual heat removal heat exchanger	Refer to subsection 5.3.4, Table 5.2-1
In-containment refueling water storage tank	ASTM A240 XM-29 or TP304
Passive containment cooling system (safety-related portion)	
Passive containment cooling system water storage tank	ASTM A240 TP304
Valves	SA-182 TP304L
Piping	SA-312 TP304L
Fittings	SA-182 TP304L
PCS Recirculation Subsystem	
Valves	SA-217 Grade WC6
Piping	SA-335 Grade P11
Fittings	SA-234 Grade WP11
Spargers	
Piping	SA-358 TP304 or TP316 or SA-312 TP304 or TP316
Fittings	SA-182 TP304 or SA-403 WP304 or WP316
Containment vessel and penetrations	Refer to subsection 3.8.2.1
Valves in contact with borated water	Refer to subsection 5.2.3, Table 5.2-1
Main control room emergency habitability system	
Valves	SA-182 Grade F11
Pipe	SA-355 Grade P11
Air storage tanks	SA-372

Table 6.1-2

AP1000 COATED SURFACES, CONTAINMENT SHELL AND SURFACES INSIDE CONTAINMENT

Surface	Boundary	Surface Material	Coating	Coating Functions/Safety Classifications		Coating Classification (1)
Containment Shell, Outside Surface	Shell surfaces above elevation 135′ 3″	Carbon Steel	Inorganic Zinc	1 Promote wettability 2 Heat conduction 3 Nondetachable 4 Inhibit corrosion	1 Safety 2 Safety 3 Safety 4 Safety	Safety – Service Level III
Containment Shell, Inside Surface	Shell surfaces above 7 feet above operating deck	Carbon Steel	Inorganic Zinc	1 Promote wettability 2 Heat conduction 3 Nondetachable 4 Inhibit corrosion	1 Safety (2) 2 Safety 3 Safety 4 Safety	Safety – Service Level I
Inside Containment	Areas surrounding the containment recirculation screens (3)	NA	NA	NA	NA	NA
	Concrete walls, ceilings and floors (4)	Concrete	Epoxy Coating System	1 Ensure settling 2 Prevent dusting 3 Protect from chemical attack 4 Enhance radioactive decontamination	1 Safety (5) 2 Nonsafety 3 Nonsafety 4 Nonsafety	Nonsafety (5) Service Level II
	Steel walls, ceilings, floors, columns, beams, braces, plates (4)	Carbon Steel	Inorganic Zinc	1 Ensure settling 2 Inhibit corrosion	1 Safety (5) 2 Nonsafety	Nonsafety (5) Service Level II
	Steel walls, ceilings, floors, columns, beams, braces, plates (4)	Carbon Steel	Epoxy Coating System	1 Ensure settling 2 Inhibit corrosion 3 Enhance radioactive decontamination	1 Safety (5) 2 Nonsafety 3 Nonsafety	Nonsafety (5) Service Level II

Notes:
1. The applicability of 10 CFR 50, Appendix B, and other codes and standards to coatings and their application are discussed in DCD subsection 6.1.2.1.6.
2. An inorganic zinc coating on the inside of the containment shell is not required to promote wettability, however it has been included in PCS testing and analysis and as a result is considered safety-related.
3. Areas around PXS recirculation screens do not require coatings as defined in DCD subsection 6.3.2.2.7.3.
4. 10 CFR 50, Appendix B, does not apply to DBA testing and manufacture of coatings in the CVS room inside containment as discussed in DCD subsection 6.1.2.1.6.
5. 10 CFR 50, Appendix B, applies to DBA testing and manufacture of these Service Level II coatings as discussed in DCD subsection 6.1.2.1.6.

6.2 Containment Systems

6.2.1 Containment Functional Design

6.2.1.1 Containment Structure

6.2.1.1.1 Design Basis

The containment system is designed such that for all break sizes, up to and including the double-ended severance of a reactor coolant pipe or secondary side pipe, the containment peak pressure is below the design pressure. A summary of the results is presented in Table 6.2.1.1-1.

This capability is maintained by the containment system assuming the worst single failure affecting the operation of the passive containment cooling system (PCS). For primary system breaks, loss of offsite power (LOOP) is assumed. For secondary system breaks, offsite power is assumed to be available when it maximizes the mass and energy released from the break. Additional discussion of the assumptions made for secondary side pipe breaks may be found in subsection 6.2.1.4.

The single failure postulated for the containment pressure/temperature calculations is the failure of one of the valves controlling the cooling water flow for the PCS. Failure of one of these valves would lead to cooling water flow being delivered to the containment vessel through two of three delivery headers. This results in reduced cooling flow for PCS operation. No other single failures are postulated in the containment analysis.

The containment integrity analyses for the AP1000 employ a multivolume lumped parameter model to study the long-term containment response to postulated Loss of Coolant Accidents (LOCA) and Main Steam Line Break (MSLB) accidents.

The analyses presented in this section are based on assumptions that are conservative with respect to the containment and its heat removal systems, such as minimum heat removal, and maximum initial containment pressure.

The containment design for the Safe Shutdown Earthquake (SSE) is discussed in subsection 3.8.2.

The minimum containment backpressure used in the Passive Core Cooling System (PXS) analysis is discussed in subsection 6.2.1.5.

6.2.1.1.2 Design Features

The operation of the PCS is discussed in subsection 6.2.2. The arrangement of the containment and internal structures is described in Section 1.2.

The reactor coolant loop is surrounded by structural walls of the containment internal structures. These structural walls are a minimum of 2-feet - 6-inches thick and enclose the reactor vessel, steam generators, reactor coolant pumps, and the pressurizer.

The containment vessel is designed and constructed in accordance with the ASME Code, Section III, Subsection NE, Metal Containment, as described in subsection 3.8.2.

Structural steel non-pressure retaining parts such as ladders, walkways, and handrails are designed to the requirements for steel structures defined in subsection 3.8.4.

The design features provide adequate containment sump levels following a design basis event as described in subsection 3.4.

Containment and subcompartment atmospheres are maintained during normal operation within prescribed pressure, temperature, and humidity limits by means of the containment air recirculation system (VCS), and the central chilled water system (VWS). The recirculation system cooling coils are provided with chilled water for temperature control. The filtration supply and exhaust subsystem can be utilized periodically to purge the containment air for pressure control. Periodic inspection and maintenance verify functional capability.

6.2.1.1.3 Design Evaluation

The Westinghouse-GOTHIC (WGOTHIC) computer code (Reference 20) is a computer program for modeling multiphase flow in a containment transient analysis. It solves the conservation equations in integral form for mass, energy, and momentum for multicomponent flow. The momentum conservation equations are written separately for each phase in the flow field (drops, liquid pools, and atmosphere vapor). The following terms are included in the momentum equation: storage, convection, surface stress, body force, boundary source, phase interface source, and equipment source.

To model the passive cooling features of the AP1000, several assumptions are made in creating the plant decks. The external cooling water does not completely wet the containment shell, therefore, both wet and dry sections of the shell are modeled in the WGOTHIC analyses. The analyses use conservative coverage fractions to determine evaporative cooling.

Heat conduction from the dry to wet section is considered in the analysis. The combination of passive containment cooling system coverage area and heat conduction from the dry to wet sections is explained in Chapter 7 of Reference 20. An analysis is also performed for the limiting LOCA event without considering heat conduction from the dry to wet section. The analyses conservatively assume that the external cooling water is not initiated until 337 seconds into the transient, allowing time to initiate the signal and to fill the headers and weirs and to develop the flow down the containment side walls. The effects of water flowing down the shell from gravitational forces are explicitly considered in the analysis.

The containment initial conditions of pressure, temperature, and humidity are provided in Table 6.2.1.1-2.

For the LOCA events, two double-ended guillotine reactor coolant system pipe breaks are analyzed. The breaks are postulated to occur in either a hot or a cold leg of the reactor coolant system. The hot leg break results in the highest blowdown peak pressure. The cold leg break results in the higher post-blowdown peak pressure. The cold leg break analysis includes the long term contribution to containment pressure from the sources of stored energy, such as the steam

generators. The LOCA mass and energy releases described in subsection 6.2.1.3 are used for these calculations.

For the MSLB event, a representative pipe break spectrum is analyzed. Various break sizes and power levels are analyzed with the WGOTHIC code. The MSLB mass and energy releases described in subsection 6.2.1.4 are used for these calculations.

The results of the LOCA and MSLB postulated accidents are provided in Table 6.2.1.1-1. A comparison of the containment integrity acceptance criteria to General Design Criteria is provided in Table 6.2.1.1-3.

The containment pressure response for the peak pressure steam line break case is provided in Figure 6.2.1.1-1. The containment temperature response for the peak temperature steam line break case is provided in Figure 6.2.1.1-2.

The passive internal containment heat sink data used in the WGOTHIC analyses is presented in Reference 20, Section 13. Data for both metallic and concrete heat sinks are presented. The containment pressure and temperature responses to a double-ended cold leg guillotine are presented in Figures 6.2.1.1-5 and 6.2.1.1-6 for the 24 hour portion of the transient and Figures 6.2.1.1-7 and 6.2.1.1-8 for the 72 hour transient. A separate analysis for the double-ended cold leg guillotine LOCA event, without considering heat conduction from the dry to wet section, results in somewhat higher containment pressure in the long term, but still below 50 percent of design pressure at 24 hours. This separate analysis confirms the assumption in subsection 15.6.5.3.3 of reducing the containment leakage to half its design value at 24 hours. The containment pressure and temperature response to a double-ended hot leg guillotine break are presented in Figures 6.2.1.1-9 and 6.2.1.1-10. The physical properties of the materials corresponding to the heat sink information are presented in Table 6.2.1.1-8.

The instrumentation provided inside containment to monitor and record the containment pressure and temperature is found in Section 7.5.

6.2.1.1.4 External Pressure Analysis

Certain design basis events and credible inadvertent systems actuation have the potential to result in containment external pressure loads. Evaluations of these events show that a loss of all ac power sources during extreme cold ambient conditions has the potential for creating the worst-case external pressure load on the containment vessel. This event leads to a reduction in the internal containment heat loads from the reactor coolant system and other active components, thus resulting in a temperature reduction within the containment and an accompanying pressure reduction. Evaluations are performed to determine the maximum external pressure to which the containment may be subjected during a postulated loss of all ac power sources.

The evaluations are performed with the assumption of a -40°F ambient temperature with a steady 48 mph wind blowing to maximize cooling of the containment vessel. The initial internal containment temperature is conservatively assumed to be 120°F, creating the largest possible temperature differential to maximize the heat removal rate through the containment vessel wall. A negative 0.2 psig initial containment pressure is used for this evaluation. A conservative maximum initial containment relative humidity of 100 percent is used to produce the greatest reduction in

containment pressure due to the loss of steam partial pressure by condensation. It is also conservatively assumed that no air leakage occurs into the containment during the transient.

Evaluations are performed using WGOTHIC with conservatively low estimates of the containment heat loads and conservatively high heat removal through the containment vessel consistent with the limiting assumptions stated above. Results of these evaluations demonstrate that at one hour after the event the net external pressure is within the 2.9 psid design external pressure. This is sufficient time for operator action to prevent the containment pressure from dropping below the design external pressure, based on the PAM's containment pressure indications (four containment pressure instruments) and the ability to mitigate the pressure reduction by opening either set of containment ventilation purge isolation valves, which are powered by the 1E batteries.

The limiting case containment pressure transient is shown in Figure 6.2.1.1-11.

6.2.1.2 Containment Subcompartments

6.2.1.2.1 Design Basis

Subcompartments within containment are designed to withstand the transient differential pressures of a postulated pipe break. These subcompartments are vented so that differential pressures remain within structural limits. The subcompartment walls are challenged by the differential pressures resulting from a break in a high energy line. Therefore, a high energy line is postulated, with a break size chosen consistent with the position presented in Section 3.6, for analyzing the maximum differential pressures across subcompartment walls.

Section 3.6 describes the application of the mechanistic pipe break criteria, commonly referred to as leak-before-break (LBB), to the evaluation of pipe ruptures. This eliminates the need to consider the dynamic effects of postulated pipe breaks for pipes which qualify for LBB. However, the analyses of containment pressure and temperature, emergency core cooling, and environmental qualification of equipment are based on double-ended guillotine (DEG) reactor coolant system breaks and through-wall cracks.

6.2.1.2.1.1 Summary of Subcompartment Pipe Break Analyses

Each subcompartment is analyzed for effects of differential pressures resulting from the break of the most limiting line in the subcompartment which has not been evaluated for LBB.

The subcompartment analysis demonstrates that the wall differential pressures resulting from the most limiting high energy line break within the subcompartments are within the design capability.

6.2.1.2.2 Design Features

The plant general arrangement drawings shown in Section 1.2 include descriptions of the containment sub-compartments and surrounding areas. The general arrangement drawings are used in assembling the subcompartment analysis model.

Vent paths considered in the analyses are shown in the general arrangement drawings and consist of floor gratings and openings through walls. In the AP1000 subcompartment analyses, no credit is taken for vent paths that become available only after the occurrence of the postulated break (such as blowout panels, doors, hinged panels and insulation collapsing).

6.2.1.2.3 Design Evaluation

The TMD computer code (Reference 2) is used in the subcompartment analysis to calculate the differential pressures across subcompartment walls. The TMD code has been reviewed by the NRC and approved for use in subcompartment differential pressure analyses.

Specific information relative to details on the analysis, such as noding diagrams, volumes, vent areas, and initial conditions, are provided in Reference 26.

The methodology used to generate the short term mass and energy releases is described in subsection 6.2.1.3.1.

The initial atmospheric conditions used in the TMD subcompartment analysis are selected so that the calculated differential pressures are maximized. These conditions are chosen according to criteria identified in subsection 6.2.1.2 of NUREG-0800 and include the maximum allowable air temperature, minimum absolute pressure, and zero percent relative humidity.

The containment and subcompartment atmospheres during normal operating conditions are maintained within prescribed pressure, temperature, and humidity limits by means of the containment air recirculation system (VCS), and the central chilled water system (VWS). The recirculation system cooling coils are provided with chilled water to provide sufficient temperature control. The filtration supply and exhaust subsystem can be utilized to purge the containment air for pressure control. Periodic inspection and maintenance are performed to verify functional capability.

6.2.1.2.3.1 Flow Equation

The flow equations used by the TMD code to calculate the flow between nodes are described in Reference 2. These flow equations are based on the unaugmented critical flow model, which demonstrate conservatively low critical flow velocity predictions compared to experimental test data. Due to the TMD calculation methods presented in subsection 1.3.1 of Reference 2, 100 percent entrainment results in the highest calculated differential pressures and therefore this degree of entrainment is conservatively assumed in the subcompartment analysis.

6.2.1.2.3.2 Pipe Breaks

The subcompartment analysis for the steam generator compartment is performed assuming a double-ended guillotine break in a 3-inch inside diameter reactor cooling system hot leg or cold leg pipe or a 4-inch double-ended steam generator blowdown line, or a 4-inch pressurizer spray line break. The breaks can be assumed to occur between the 84-foot elevation and the 135-foot elevation of the steam generator compartment. Because the TMD code assumes homogeneous mixtures within a node, the specific location of the break within the node is not critical to the differential pressure calculation. No flow restrictions exist that limit the flow out of the break.

The analysis for the pressurizer compartment pipe and valve room is performed assuming a double-ended guillotine break in a 4-inch inside diameter reactor coolant system spray line. This break envelopes the branch lines that could be postulated to rupture in this area. The break is

assumed to occur between the 107-foot elevation and the 171-foot elevation of the pressurizer compartment or the 118-foot to 135-foot elevations of the pressurizer spray valve room.

The analysis for the steam generator vertical access area is performed assuming a double-ended guillotine break in a 3-inch inside diameter reactor coolant system cold-leg pipe. This break envelopes the branch lines that could be postulated to rupture in this area. The break is assumed to occur between the 83-foot elevation and the 103-foot elevation of the steam generator vertical access area compartment.

The analysis for the maintenance floor and operating deck compartments are performed assuming a one square foot rupture of a main steam line pipe. This break envelopes the branch lines that could be postulated to rupture in these areas. The break is assumed to occur between the 107-foot elevation and the 135-foot elevation of the maintenance floor compartment and between the 135-foot elevation and the 282-foot elevation of the operating deck region.

The analysis for the main chemical and volume control system room is performed assuming a single-ended guillotine break in a 3-inch diameter reactor coolant system cold-leg pipe. This break envelopes the branch lines that could be postulated to rupture in this area. The break is assumed to occur between the 91-foot elevation and the 105-foot elevation of the chemical and volume control system room compartment.

The analysis for the pipe tunnel in the chemical and volume control system room is performed assuming a double-ended guillotine break in a 4-inch diameter steam generator blowdown line. This double-ended break envelopes the branch lines that could be postulated to rupture in this area. The break is assumed to occur between the 98.5-foot elevation and the 105-foot elevation of the chemical and volume control system room pipe tunnel.

An evaluation of rooms which could have either a main or startup feedwater line break was performed. No significant pressurization of the regions is predicted to occur because the postulated breaks are located in regions which are open to the large free volume of containment. For these regions, the main or startup feedwater line breaks are not limiting.

6.2.1.2.3.3 Node Selection

The nodalization for the sub-compartments is analyzed in sufficient detail such that nodal boundaries are at the location of flow obstructions or geometrical changes within the subcompartment. These discontinuities create pressure differentials between adjoining nodes. There are no significant discontinuities within each node, and hence the pressure gradient is negligible within any node.

6.2.1.2.3.4 Vent Flowpath Flow Conditions

The flow characteristics for each of the subcompartments are such that, at no time during the transient does critical flow exist through vent paths.

6.2.1.3 Mass and Energy Release Analyses for Postulated Pipe Ruptures

Mass and Energy releases are documented in this section for two different types of transients.

The first section describes the methodology used to calculate the releases for the subcompartment differential pressure analysis using the TMD code (referred to as the short term analysis). These releases are used for the subcompartment response in subsection 6.2.1.2.

The second section describes the methodology used to determine the releases for the containment pressure and temperature calculations using the WGOTHIC code (Reference 20) (referred to as the long term analysis). These releases are used for the containment integrity analysis in subsection 6.2.1.1.

The short term analysis considers only the initial stages of the blowdown transient, and takes into consideration the application of LBB methodology. LBB is discussed in subsection 3.6.3. Since LBB is applicable to reactor coolant system piping that is 6 inches in diameter and greater, the mass and energy release analysis for sub-compartments postulates the complete DEG severance of 3-inch and 4-inch pipe. The mass and energy release postulated for a ruptured steam line is for a one square foot break.

Conversely, the limiting break size for containment integrity analysis considers as its LOCA design basis the complete DEG severance of the largest reactor coolant system pipe.

The containment system receives mass and energy releases following a postulated rupture of the reactor coolant system. The release rates are calculated for pipe failure at two locations: the hot leg and the cold leg. These break locations are analyzed for both the short-term and the long-term transients. Because the initial operating pressure of the reactor coolant system is approximately 2250 psi, the mass and energy are released extremely rapidly when the break occurs. As the water exits from the broken pipe, a portion of it flashes to steam because of the differences in pressure and temperature between the reactor coolant system and containment. The reactor coolant system depressurizes rapidly since break flow exits from both sides of the pipe in a DEG severance.

6.2.1.3.1 Short Term Mass and Energy Release Data

The AP1000 short term LOCA mass and energy releases are predicted for the first ten seconds of the blowdown from a postulated DEG break of the largest non-LBB high energy line in each compartment. The density of the fluid released from a postulated pipe rupture has a direct effect on the magnitude of the differential pressures that results across subcompartment walls. A DEG rupture that is postulated in the cold leg piping is typically the most limiting scenario. This analysis provides mass and energy releases for a 3-inch DEG rupture in the cold leg and in the hot leg.

The modified Zaloudek correlation (Reference 3) is used to calculate the critical mass flux from a 3-inch double-ended cold leg guillotine (DECLG) break and a 3-inch double-ended hot leg guillotine (DEHLG) break. This maximum mass flux is conservatively assumed to remain constant at the initial AP1000 full power steady state conditions and the enthalpy is varied to determine the energy release rates. Conservative enthalpies are obtained from the SATAN-VI blowdown transients for ruptures of the largest reactor coolant system cold leg and hot leg piping in the AP1000 design. This assumption maximizes the mass released, which is conservative for the subcompartment analysis.

The mass release for the 4-inch pressurizer spray line break is determined with the Fauske break flow model in NOTRUMP. The steam generator blowdown releases for a 4-inch line are calculated with the critical mass flux method.

The initial conditions and inputs to the modified Zaloudek correlation used for the AP1000 LOCA mass and energy releases are given in Table 6.2.1.3-1. The temperature parameters that are used for the hot leg and cold leg are conservative compared to the actual plant performance parameters. The short term LOCA mass and energy releases are affected by the initial density of the fluid. A lower density yields a more conservative maximum compartment differential pressure.

The short term LOCA double-ended guillotine mass and energy release data is provided in Tables 6.2.1.3-2 and 6.2.1.3-3 for the cold and hot legs, respectively. The short-term non-LOCA mass and energy release data are provided in Tables 6.2.1.3-4 and 6.2.1.3-5. The pressurizer spray line mass and energy releases are shown in Table 6.2.1.3-6. The short term LOCA single-ended mass and energy release data are provided in Table 6.2.1.3-7.

6.2.1.3.2 Long Term Mass and Energy Release Data

A long term LOCA analysis calculational model is typically divided into four phases: blowdown, which includes the period from the accident initiation (when the reactor is in a steady-state full power operation condition) to the time that the broken loop pressure equalizes to the containment pressure; refill, which is the time from the end of the blowdown to the time when the passive core cooling system (PXS) refills the vessel lower plenum; reflood, which begins when the water starts to flood the core and continues until the core is completely quenched; and post-reflood, which is the period after the core has been quenched and energy is released to the reactor coolant system primary system by the reactor coolant system metal, core decay heat, and the steam generators.

The long-term analysis considers the blowdown, reflood, and post-reflood phases of the transient. The refill period is conservatively neglected so that the releases to the containment are conservatively maximized.

The AP1000 long-term LOCA mass and energy releases are predicted for the blowdown phase for postulated DECLG and DEHLG breaks. The blowdown phase mass and energy releases are calculated using the NRC approved SATAN-VI computer code (Reference 4). The post blowdown phase mass and energy releases are calculated considering the energy released from the available energy sources described below. The energy release rates are conservatively modeled so that the energy is released quickly. The higher release rates result in a conservative containment pressure calculation. The releases are provided in Tables 6.2.1.3-9 and 6.2.1.3-10.

6.2.1.3.2.1 Mass and Energy Sources

The following are accounted for in the long-term LOCA mass and energy calculation:

- Decay heat
- Core stored energy
- Reactor coolant system fluid and metal energy

- Steam Generator fluid and metal energy
- Accumulators core make-up tanks (CMTs), and the in-containment refueling water storage tank (IRWST)
- Zirconium-water reaction

The methods and assumptions used to release the various energy sources during the blowdown phase are given in Reference 4.

The following parameters are used to conservatively analyze the energy release for maximum containment pressure:

- Maximum expected operating temperature
- Allowance in temperature for instrument error and dead band
- Margin in volume (+1.4 percent)
- Allowance in volume for thermal expansion (+1.6 percent)
- 100 percent full power operation
- Allowance for calorimetric error (+1.0 percent of full power)
- Conservatively modified coefficients of heat transfer
- Allowance in core stored energy for effect of fuel densification
- Margin in core stored energy (+15.0 percent)
- Allowance in pressure for instrument error and dead band
- Margin in steam generator mass inventory (+10.0 percent)
- One percent of the Zirconium surrounding the fuel is assumed to react

6.2.1.3.2.2 Description of Blowdown Model

A description of the SATAN-VI model that is used to determine the mass and energy released from the reactor coolant system during the blowdown phase of a postulated LOCA is provided in Reference 4. Significant correlations are discussed in this reference.

6.2.1.3.2.3 Description of Post-Blowdown Model

The remaining reactor coolant system and SG mass and energy inventories at the end of blowdown are used to define the initial conditions for the beginning of the reflood portion of the transient. The broken and unbroken loop SG inventories are kept separate to account for potential differences in the cooldown rate between the loops. In addition, the mass added to the reactor coolant system from the IRWST is returned to containment as break flow so that no net change in system mass occurs.

Energy addition due to decay heat is computed using the 1979 ANS standard (plus 2 sigma) decay heat table from Reference 4. The energy release rates from the reactor coolant system metal and steam generators are modelled using exponential decay rates. This modelling is consistent with analyses for current generation design analyses that are performed with the models described in Reference 4.

The accumulator, CMT, and IRWST mass flow rates are computed from the end of blowdown to the time the tanks empty. The rate of reactor coolant system mass accumulation is assumed to decrease exponentially during the reflood phase. More CMT and accumulator flow is spilled from the break as the system refills. The break flow rate is determined by subtracting the reactor coolant system mass addition rate from the sum of the accumulator, CMT and IRWST flow rates.

Mass which is added to, and which remains in, the vessel is assumed to be raised to saturation. Therefore, the actual amount of energy available for release to the containment for a given time period is determined from the difference between the energy required to raise the temperature of the incoming flow to saturation and the sum of the decay heat, core stored energy, reactor coolant system metal energy and SG mass and metal energy release rates. The energy release rate for the available break flow is determined from a comparison of the total energy available release rate and the energy release rate assuming that the break flow is 100-percent saturated steam. Saturated steam releases maximize the calculated containment pressurization.

6.2.1.3.2.4 Single Failure Analysis

The assumptions for the containment mass and energy release analysis are intended to maximize the calculated release. A single failure could reduce the flow rate of water to the RCS, but would not disable the passive core cooling function. For example, if one of the two parallel valves from the CMT were to fail to open, the injection flow rate would be reduced and, as a result, the break mass release rate would decrease. Therefore, to maximize the releases, the AP1000 mass and energy release calculations conservatively do not assume a single failure. The effects of a single failure are taken into account in the containment analysis of subsection 6.2.1.1.

6.2.1.3.2.5 Metal-Water Reaction

Consistent with 10 CFR 50, Appendix K criteria, the energy release associated with the zirconium-water exothermic reaction has been considered. The LOCA peak cladding temperature analysis, presented in Chapter 15, that demonstrates compliance with the Appendix K criteria demonstrates that no appreciable level of zirconium oxidation occurs. This level of reaction has been bounded in the containment mass and energy release analysis by incorporating the heat of reaction from 1 percent of the zirconium surrounding the fuel. This exceeds the level predicted by the LOCA analysis and results in additional conservatism in the mass and energy release calculations.

6.2.1.3.2.6 Energy Inventories

Inventories of the amount of mass and energy released to containment during a postulated LOCA are provided in summary Tables 6.2.1.3-2 through 6.2.1.3-7.

6.2.1.3.2.7 Additional Information Required for Confirmatory Analysis

System parameters and hydraulic characteristics needed to perform confirmatory analysis are provided in Table 6.2.1.3-8 and Figures 6.2.1.3-1 through 6.2.1.3-4.

6.2.1.4 Mass and Energy Release Analysis for Postulated Secondary-System Pipe Rupture Inside Containment

Steam line ruptures occurring inside a reactor containment structure may result in significant releases of high-energy fluid to the containment environment, possibly resulting in high containment temperatures and pressures. The quantitative nature of the releases following a steam line rupture is dependent upon the configuration of the plant steam system, the containment design as well as the plant operating conditions and the size of the rupture. This section describes the methods used in determining the containment responses to a variety of postulated pipe breaks encompassing variations in plant operation.

6.2.1.4.1 Significant Parameters Affecting Steam Line Break Mass and Energy Releases

Four major factors influence the release of mass and energy following a steam line break: steam generator fluid inventory, primary-to-secondary heat transfer, protective system operation and the state of the secondary fluid blowdown. The following is a list of those plant variables which have significant influence on the mass and energy releases:

- Plant power level
- Main feedwater system design
- Startup feedwater system design
- Postulated break type, size, and location
- Availability of offsite power
- Safety system failures
- Steam generator reverse heat transfer and reactor coolant system metal heat capacity.

The following is a discussion of each of these variables.

6.2.1.4.1.1 Plant Power Level

Steam line breaks are postulated to occur with the plant in any operating condition ranging from hot shutdown to full power. Since steam generator mass decreases with increasing power level, breaks occurring at lower power generally result in a greater total mass release to the containment. Because of increased energy storage in the primary plant, increased heat transfer in the steam generators and additional energy generation in the nuclear fuel, the energy released to the containment from breaks postulated to occur during power operation may be greater than for breaks occurring with the plant in a hot shutdown condition. Additionally, steam pressure and the dynamic conditions in the steam generators change with increasing power. They have significant influence on the rate of blowdown from the break following a steam break event.

Because of the opposing effects of changing power level on steam line break releases, no single power level can be pre-defined as a worst case initial condition for a steam line break event. Therefore, several different power levels (101%, 70%, 30%, 0%) spanning the operating range as well as the hot shutdown condition are analyzed.

6.2.1.4.1.2 Main Feedwater System Design

The rapid depressurization that occurs following a rupture may result in large amounts of water being added to the steam generators through the main feedwater system. Rapid closing isolation valves are provided in the main feedwater lines to limit this effect. The piping layout downstream of the isolation valves determine the volume in the feedwater lines that cannot be isolated from the steam generators. As the steam generator pressure decreases, some of the fluid in this volume will flash into the steam generator, providing additional secondary fluid that may exit out the rupture. This unisolated feedwater mass between the steam generator and isolation valve is accounted for within the results in subsection 6.2.1.4.3.2. The assumed unisolable volume bounds the volume to either the feedwater control valve or the feedwater isolation valve on the faulted loop, so that no additional feedwater mass could be postulated due to a single failure of one of the valves.

The feedwater addition that occurs prior to closing of the feedwater line isolation valves is conservatively calculated based on the depressurization of the faulted steam generator, and assuming that the feedwater control valve is fully open in response to the increased steam flow rate.

6.2.1.4.1.3 Startup Feedwater System Design

Within the first minute following a steam line break, the startup feedwater system may be initiated on any one of several protection system signals. The addition of startup feedwater to the steam generators increases the secondary mass available for release to the containment, as well as the heat transferred to the secondary fluid. The effects on the steam generator mass are maximized in the calculation described in subsection 6.2.1.4.3.2 by assuming full startup feedwater flow to the faulted steam generator starting at time zero from the safeguard system(s) signal and continuing until automatically terminated on a low RCS Tcold signal.

6.2.1.4.1.4 Postulated Break Type, Size and Location

The steamline break is postulated as a full double-ended pipe rupture immediately downstream of the integral flow restrictor on the faulted steam generator. The forward break flow from the faulted steam generator is controlled by the flow restrictor area (1.4 ft^2). The reverse break flow is based on the cross-sectional area of the steam line (6.68 ft^2). After the initial steam in the steamline is released, the reverse break flow becomes controlled by the area of the flow restrictor (1.4 ft^2) on the intact steam generator. The faulted steam generator is unisolable from the break location, and the forward break flow continues until the steam generator is empty. The reverse break flow continues until main steamline isolation valve (MSIV) closure. The modeling of the reverse break flow does not differentiate the location of the MSIVs, and all steam that has exited the intact steam generator prior to MSIV closure is assumed to be released out the break. This bounds the possible effects of an MSIV failed open.

No liquid entrainment is credited in the break effluent from the double-ended pipe rupture. The release of dry saturated steam from the largest possible break size maximizes the mass and energy release to the containment.

6.2.1.4.1.5 Availability of Offsite Power

The effects of the assumption of the availability of offsite power are enveloped in the analysis.

Offsite power is assumed to be available where it maximizes the mass and energy released from the break because of the following:

- The continued operation of the reactor coolant pumps until automatically tripped as a result of core makeup tank (CMT) actuation. This maximizes the energy transferred from the reactor coolant system to the steam generator.

- The continued operation of the feedwater pumps and actuation of the startup feedwater system until they are automatically terminated. This maximizes the steam generator inventories available for release.

- The AP1000 is equipped with the passive safeguards system including the CMT and the passive residual heat removal (PRHR) heat exchanger. Following a steam line rupture, these passive systems are actuated when their setpoints are reached. This decreases the primary coolant temperatures. The actuation and operation of these passive safeguards systems do not require the availability of offsite power.

  When the PRHR is in operation, the core-generated heat is dissipated to the in-containment refueling water storage tank (IRWST) via the PRHR heat exchanger. This causes a reduction of the heat transfer from the primary system to the steam generator secondary system and causes a reduction of mass and energy releases via the break.

Thus, the availability of ac power in conjunction with the passive safeguards system (CMT and PRHR) maximizes the mass and energy releases via the break. Therefore, blowdown occurring in conjunction with the availability of offsite power is more severe than cases where offsite power is not available.

6.2.1.4.1.6 Safety System Failures

The calculation of the mass and energy release following a steamline rupture is done to conservatively bound the possible increase of mass release due to safety system failures. Two failures, which are bounded are:

- Failure of one main steam isolation valve, as discussed in subsection 6.2.1.4.1.4
- Failure of one main feedwater isolation valve, as discussed in subsection 6.2.1.4.1.2

6.2.1.4.1.7 Steam Generator Reverse Heat Transfer and Reactor Coolant System Metal Heat Capacity

Once steam line isolation is complete, the steam generator in the intact steam loop becomes a source of energy that can be transferred to the steam generator with the broken line. This energy transfer occurs through the primary coolant. As the primary plant cools, the temperature of the coolant flowing in the steam generator tubes drops below the temperature of the secondary fluid in the intact unit, resulting in energy being returned to the primary coolant. This energy is then available to be transferred to the steam generator with the broken steam line.

Similarly, the heat stored in the metal of the reactor coolant piping, the reactor vessel, and the reactor coolant pumps is transferred to the primary coolant as the plant cooldown progresses. This energy also is available to be transferred to the steam generator with the broken line.

The effects of both the reactor coolant system metal and the reverse steam generator heat transfer are included in the results presented.

6.2.1.4.2 Description of Blowdown Model

The steamline blowdown is calculated with the AP1000 version of LOFTRAN (Reference 31 and 32). This is a version of LOFTRAN (Reference 6) which has been modified to include simulation of the AP1000 passive residual heat removal heat exchanger, core makeup tanks, and associated protection and safety monitoring system actuation logic. Documentation of the code changes for the passive models is provided in Reference 31. The methodology for the steamline break analysis is based on Reference 5. The applicability of the LOFTRAN code to AP1000, and the applicability of the methodology used to analyze the steamline break blowdown are discussed in Reference 32.

6.2.1.4.3 Containment Response Analysis

The WGOTHIC Computer Code (Reference 20) is used to determine the containment responses following the steam line break. The containment response analysis is described in subsection 6.2.1.1.

6.2.1.4.3.1 Initial Conditions

The initial containment conditions are discussed in subsection 6.2.1.1.3.

6.2.1.4.3.2 Mass and Energy Release Data

Using References 5, 6, 31 and 32 as a basis, mass and energy release data are developed to determine the containment pressure-temperature response for the spectrum of breaks analyzed. Table 6.2.1.4-2 provides the mass and energy release data for the cases that produce the highest containment pressure and temperature in the containment response analysis. Table 6.2.1.4-4 provides nominal plant data used in the mass and energy releases determination.

6.2.1.4.3.3 Containment Pressure-Temperature Results

The results of the containment pressure-temperature analyses for the postulated secondary system pipe ruptures that produce the highest peak containment pressure and temperature are presented in subsection 6.2.1.1.3.

6.2.1.5 Minimum Containment Pressure Analysis for Performance Capability Studies of Emergency Core Cooling System (PWR)

The containment backpressure used for the AP1000 cold leg guillotine and split breaks for the emergency core cooling system (ECCS) analysis presented in subsection 15.6.5 is described. The minimum containment backpressure for emergency core cooling system performance during a

loss-of-coolant accident is computed using the WGOTHIC computer code. Subsection 6.2.1.1 demonstrates that the AP1000 containment pressurizes during large break LOCA events. An analysis is performed to establish a containment pressure boundary condition applied to the WCOBRA/TRAC code (Reference 8). A single-node containment model is used to assess containment pressure response. Containment internal heat sinks used heat transfer correlations of 4 times Tagami during the blowdown phase followed by 1.2 times Uchida for the post-blowdown phase. The calculated containment backpressure is provided in Figure 6.2.1.5-1. Results of the WCOBRA/TRAC analyses demonstrate that the AP1000 meets 10 CFR 50.46 requirements (Reference 7).

6.2.1.5.1 Mass and Energy Release Data

The mass and energy releases to the containment during the blowdown portion only of the double-ended cold-leg guillotine break (DECLG) transient are presented in Table 6.2.1.5-1, as computed by the WCOBRA/TRAC code.

The mathematical models which calculate the mass and energy releases to the containment are described in subsection 15.6.5. A break spectrum analysis is performed (see references in subsection 15.6.5) that considers various break sizes and Moody discharge coefficients for the double-ended cold leg guillotines and splits. Mixing of steam and accumulator water injected into the vessel reduces the available energy released to the containment vapor space, thereby minimizing calculated containment pressure. Note that the mass/energy releases during the reflood phase of the subject break are not considered. This produces a conservatively low containment pressure result for use as a boundary condition in the WCOBRA/TRAC large break LOCA analysis.

6.2.1.5.2 Initial Containment Internal Conditions

Initial containment conditions were biased for the emergency core cooling system backpressure analysis to predict a conservatively low containment backpressure. Initial containment conditions include an initial pressure of 14.7 psia, initial containment temperature of 90°F, and a relative humidity of 99 percent. An air annulus temperature of 0°F is assumed. The initial through-thickness metal temperature of the containment shell is assumed to also be 0°F.

6.2.1.5.3 Other Parameters

Containment parameters, such as containment volume and passive heat sinks, are biased to predict a conservative low containment backpressure. The containment volume used in the calculation is conservatively set to 1.1 times the free volume of the AP1000 containment Evaluation Model. Passive heat sink surface areas were increased by a factor of 2.1 times the values presented in Reference 20. Material properties were biased high (density, conductivity, and heat capacity) as indicated in CSB 6-1 (Reference 8). No air gap was modeled between the steel liner and base concrete of jacketed concrete heat sinks. The outside surface of the containment shell was maintained at 0°F throughout the calculation. To further minimize containment pressure, containment purge was assumed to be in operation at time zero and air is vented through both the 15-inch diameter (16-inch, Sch. 40 piping) containment purge supply and exhaust lines until the

isolation valves have fully closed. These valves were modeled to close 12 seconds after the 8 psig closure setpoint was reached.

6.2.1.6 Testing and Inspection

This section describes the functional testing of the containment vessel. Testing and in-service inspection of the containment vessel are described in subsection 3.8.2.6. Isolation testing and leak testing are described in subsection 6.2.5. Testing and inspection are consistent with regulatory requirements and guidelines.

The valves of the passive containment cooling system are stroke tested periodically. Subsection 6.2.2 provides a description of testing and inspection.

The baffle between the containment vessel and the shield building is equipped with removable panels and clear observation panels to allow for inspection of the containment surface. See subsection 3.8.2 for the requirements for in-service inspection of the steel containment vessel. Subsection 6.2.2 provides a description of testing and inspection to be performed.

Testing is not required on any subcompartment vent or on the collection of condensation from the containment shell. The collection of condensate from the containment shell and its use in leakage detection are discussed in subsection 5.2.5.

6.2.1.7 Instrumentation Requirements

Instrumentation is provided to monitor the conditions inside the containment and to actuate the appropriate engineered safety features, should those conditions exceed the predetermined levels. The instruments measure the containment pressure, containment atmosphere radioactivity, and containment hydrogen concentration. Instrumentation to monitor reactor coolant system leakage into containment is described in subsection 5.2.5.

The containment pressure is measured by four independent pressure transmitters. The signals are fed into the engineered safety features actuation system, as described in subsection 7.3.1. Upon detection of high pressure inside the containment, the appropriate safety actuation signals are generated to actuate the necessary safety-related systems. Low pressure is alarmed but does not actuate the safety-related systems.

The physically separated pressure transmitters are located inside the containment. Section 7.3 provides a description.

The containment atmosphere radiation level is monitored by four independent area monitors located above the operating deck inside the containment building. The measurements are continuously fed into the engineered safety features actuation system logic. Section 11.5 provides information on the containment area radiation monitors. The engineered safety features actuation system operation is described in Section 7.3.

The containment hydrogen concentration is measured by hydrogen monitors, as described in subsection 6.2.4. Hydrogen concentrations are monitored by three sensors distributed throughout containment to provide a representative indication of bulk containment hydrogen concentration.

These indications are used by the plant operators to monitor hydrogen concentrations. High hydrogen concentration is alarmed in the main control room.

6.2.2 Passive Containment Cooling System

The passive containment cooling system (PCS) is an engineered safety features system. Its functional objective is to reduce the containment temperature and pressure following a loss of coolant accident (LOCA) or main steam line break (MSLB) accident inside the containment by removing thermal energy from the containment atmosphere. The passive containment cooling system also serves as the means of transferring heat to the safety-related ultimate heat sink for other events resulting in a significant increase in containment pressure and temperature.

The passive containment cooling system limits releases of radioactivity (post-accident) by reducing the pressure differential between the containment atmosphere and the external environment, thereby diminishing the driving force for leakage of fission products from the containment to the atmosphere. This subsection describes the safety design bases of the safety-related containment cooling function. Nonsafety-related containment cooling, a function of the containment recirculation cooling system, is described in subsection 9.4.6.

The passive containment cooling system also provides a source of makeup water to the spent fuel pool in the event of a prolonged loss of normal spent fuel pool cooling.

6.2.2.1 Safety Design Basis

- The passive containment cooling system is designed to withstand the effects of natural phenomena such as ambient temperature extremes, earthquakes, winds, tornadoes, or floods.

- Passive containment cooling system operation is automatically initiated upon receipt of a Hi-2 containment pressure signal.

- The passive containment cooling system is designed so that a single failure of an active component, assuming loss of offsite or onsite ac power sources, will not impair the capability of the system to perform its safety-related function.

- Active components of the passive containment cooling system are capable of being tested during plant operation. Provisions are made for inspection of major components in accordance with the intervals specified in the ASME Code, Section XI.

- The passive containment cooling system components required to mitigate the consequences of an accident are designed to remain functional in the accident environment and to withstand the dynamic effects of the accident.

- The passive containment cooling system is capable of removing sufficient thermal energy including subsequent decay heat from the containment atmosphere following a design basis event resulting in containment pressurization such that the containment pressure remains below the design value with no operator action required for 72 hours.

- The passive containment cooling system is designed and fabricated to appropriate codes consistent with Regulatory Guides 1.26 and 1.32 and in accordance with Regulatory Guide 1.29 as described in Section 1.9.

6.2.2.2 System Design

6.2.2.2.1 General Description

The passive containment cooling system and components are designed to the codes and standards identified in Section 3.2; flood design is described in Section 3.4; missile protection is described in Section 3.5. Protection against dynamic effects associated with the postulated rupture of piping is described in Section 3.6. Seismic and environmental design and equipment qualification are described in Sections 3.10 and 3.11. The actuation system is described in Section 7.3.

6.2.2.2.2 System Description

The passive containment cooling system is a safety-related system which is capable of transferring heat directly from the steel containment vessel to the environment. This transfer of heat prevents the containment from exceeding the design pressure and temperature following a postulated design basis accident, as identified in Chapters 6 and 15. The passive containment cooling system makes use of the steel containment vessel and the concrete shield building surrounding the containment. The major components of the passive containment cooling system are: the passive containment cooling water storage tank (PCCWST) which is incorporated into the shield building structure above the containment; an air baffle, located between the steel containment vessel and the concrete shield building, which defines the cooling air flowpath; air inlets and an air exhaust, also incorporated into the shield building structure; and a water distribution system, mounted on the outside surface of the steel containment vessel, which functions to distribute water flow on the containment. A passive containment cooling ancillary water storage tank and two recirculation pumps are provided for onsite storage of additional passive containment cooling system cooling water, to transfer the inventory to the passive containment cooling water storage tank, and to provide a back-up supply to the fire protection system (FPS) seismic standpipe system as discussed in subsection 9.5.1.

A normally isolated, manually-opened flow path is available between the passive containment cooling system water storage tank and the spent fuel pool.

A recirculation path is provided to control the passive containment cooling water storage tank water chemistry and to provide heating for freeze protection. Passive containment cooling water storage tank filling operations and normal makeup needs are provided by the demineralized water transfer and storage system discussed in subsection 9.2.4.

The system piping and instrumentation diagram is shown in Figure 6.2.2-1. System parameters are shown in Table 6.2.2-1. A simplified system sketch is included as Figure 6.2.2-2.

6.2.2.2.3 Component Description

The mechanical components of the passive containment cooling system are described in this subsection. Table 6.2.2-2 provides the component design parameters.

Passive Containment Cooling Water Storage Tank – The passive containment cooling water storage tank is incorporated into the shield building structure above the containment vessel. The inside wetted walls of the tank are lined with stainless steel plate. It is filled with demineralized water and has the minimum required useable volume for the passive containment cooling function as defined in Table 6.2.2-2. The passive containment cooling system functions as the safety-related ultimate heat sink. The passive containment cooling water storage tank is seismically designed and missile protected.

The surrounding reinforced concrete supporting structure is designed to ACI 349 as described in subsection 3.8.4.3. The welded seams of the plates forming part of the leak tight boundary are examined by liquid penetrant after fabrication to confirm that the boundary does not leak.

The tank also has redundant level measurement channels and alarms for monitoring the tank water level and redundant temperature measurement channels to monitor and alarm for potential freezing. To maintain system operability, a recirculation loop that provides chemistry and temperature control is connected to the tank.

The tank is constructed to provide sufficient thermal inertia and insulation such that draindown can be accomplished without heater operation.

In addition to its containment heat removal function, the passive containment cooling water storage tank also serves as a source of makeup water to the spent fuel pool and a seismic Category I water storage reservoir for fire protection following a safe shutdown earthquake.

The PCCWST suction pipe for the fire protection system is configured so that actuation of the fire protection system will not infringe on the usable capacity allocated to the passive containment cooling function as defined in Table 6.2.2-2.

Passive Containment Cooling Water Storage Tank Isolation Valves – The passive containment cooling system water storage tank outlet piping is equipped with three sets of redundant isolation valves. In two sets, air-operated butterfly valves are normally closed and open upon receipt of a Hi-2 containment pressure signal. These valves fail-open, providing a fail-safe position, on the loss of air or loss of 1E dc power. In series with these valves are normally-open motor-operated gate valves located upstream of the butterfly valves. They are provided to allow for testing or maintenance of the butterfly valves. A third set of motor-operated gate valves is provided. One valve is normally closed, and the other is normally open. Based on PRA insights, diversity requirements are adopted for these valves to minimize the consequences of common-mode failure of motor-operated valves to cause a loss of containment cooling in multiple failure scenarios.

The storage tank isolation valves, along with the passive containment cooling water storage tank discharge piping and associated instrumentation between the passive containment cooling water storage tank and the downstream side of the isolation valves, are contained within a temperature-controlled valve room to prevent freezing. Valve room heating is provided to maintain the room temperature above 50°F.

Flow Control Orifices – Orifices are installed in each of the four passive containment cooling water storage tank outlet pipes. They are used, along with the different elevations of the outlet pipes, to control the flow of water from the passive containment cooling water storage tank as a function of water level. The orifices are located within the temperature-controlled valve room.

Water Distribution Bucket – A water distribution bucket is provided to deliver water to the outer surface of the containment dome. The redundant passive containment cooling water delivery pipes and auxiliary water source piping discharge into the bucket, below its operational water level, to prevent excessive splashing. A set of circumferentially spaced distribution slots are included around the top of the bucket. The bucket is hung from the shield building roof and suspended just above the containment dome for optimum water delivery. The structural requirements for safety-related structural steel identified in subsection 3.8.4 apply to the water distribution bucket. ANSI/ASCE-8-90 (Reference 24) is used for design and analysis of stainless steel cold formed parts. The water distribution bucket is fabricated from one or more of the materials included in Table 3.8.4-6, ASTM-A240 austenitic stainless steel, or ASTM-A276 austenitic stainless steel.

Water Distribution Weir System – A weir-type water delivery system is provided to optimize the wetted coverage of the containment shell during passive containment cooling system operation. The water delivered to the center of the containment dome by the water distribution bucket flows over the containment dome, being distributed evenly by slots in the distribution bucket. Vertical divider plates are attached to the containment dome and originate at the distribution bucket extending radially along the surface of the dome to the first distribution weir. The divider plates limit maldistribution of flow which might otherwise occur due to variations in the slope of the containment dome. At the first distribution weir set, the water in that sector is collected and then redistributed onto the containment utilizing channeling walls and collection troughs equipped with distribution weirs. A second set of weirs are installed on the containment dome at a greater radius to again collect and then redistribute the cooling water to enhance shell coverage. The system includes channeling walls and collection troughs, equipped with distribution weirs. The distribution system is capable of functioning during extreme low- or high-ambient temperature conditions. The structural requirements for safety-related structural steel and cold formed steel structures identified in subsection 3.8.4 apply to the water distribution weir system. ANSI/ASCE-8-90, (Reference 24) is used for design and analysis of stainless steel cold formed parts. The water distribution weir system is fabricated from one or more of the materials included in Table 3.8.4-6, ASTM-A240 austenitic stainless steel, or ASTM-A276 austenitic stainless steel.

Air Flow Path – An air flow path is provided to direct air along the outside of the containment shell to provide containment cooling. The air flow path includes a screened shield building inlet, an air baffle that divides the outer and inner flow annuli, and a chimney to increase buoyancy. Subsection 3.8.4.1.3 includes information regarding the air baffle. The general arrangement drawings provided in Section 1.2 provide layout information of the air flow path.

Passive Containment Cooling Ancillary Water Storage Tank – The passive containment cooling ancillary water storage tank is a cylindrical steel tank located at ground level near the auxiliary building. It is filled with demineralized water and has a useable volume of greater than required for makeup to the passive containment cooling water storage tank and the spent fuel pool as defined in Table 6.2.2-2. The tank is analyzed, designed and constructed using the method and criteria for Seismic Category II building structures defined in subsections 3.2.1 and 3.7.2. The

tank is designed and analyzed for Category 5 hurricanes including the effects of sustained winds, maximum gusts, and associated wind-borne missiles.

The tank has a level measurement, an alarm for monitoring the tank water level and a temperature measurement channel to monitor and alarm for potential freezing. To maintain system operability, an internal heater, controlled by the temperature instrument, is provided to maintain water contents above freezing. Chemistry can be adjusted by passive containment cooling water storage tank recirculation loop.

The tank is insulated to assure sufficient thermal inertia of the contents is available to prevent freezing for 7 days without heater operation. The transfer piping is maintained dry also to preclude freezing.

Chemical Addition Tank – The chemical addition tank is a small, vertical, cylindrical tank that is sized to inject a solution of hydrogen peroxide to maintain a passive containment cooling water storage tank concentration for control of algae growth.

Recirculation Pumps – Each recirculation pump is a 100 percent capacity centrifugal pump with wetted components made of austenitic stainless steel. The pump is sized to recirculate the entire volume of PCCWST water once every week. Each pump is capable of providing makeup flow to both the PCCWST and the spent fuel pool simultaneously. Both pumps are operated in parallel to meet fire protection system requirements.

Recirculation Heater – The recirculation heater is provided for freeze protection. The heater is sized based on heat losses from the passive containment cooling water storage tank and recirculation piping at the minimum site temperature, as defined in Section 2.3.

6.2.2.2.4 System Operation

Operation of the passive containment cooling system is initiated upon receipt of two out of four Hi-2 containment pressure signals. Manual actuation by the operator is also possible from either the main control room or remote shutdown workstation. System actuation consists of opening the passive containment cooling water storage tank isolation valves. This allows the passive containment cooling water storage tank water to be delivered to the top, external surface of the steel containment shell. The flow of water, provided entirely by the force of gravity, forms a water film over the dome and side walls of the containment structure.

The flow of water to the containment outer surface is initially established for short-term containment cooling following a design basis loss of coolant accident. The flow rate is reduced over a period of not less than 72 hours. This flow provides the desired reduction in containment pressure over time and removes decay heat. The flow rate change is dependent only upon the decreasing water level in the passive containment cooling water storage tank. Prior to 72 hours after the event, operator actions are taken to align the passive containment ancillary water storage tank to the suction of the passive containment cooling system recirculation pumps to replenish the cooling water supply to the passive containment cooling water storage tank. Sufficient inventory is available within the passive containment cooling ancillary water storage tank to maintain the minimum flow rate for an additional 4 days. The passive containment cooling system performance parameters are identified in Table 6.2.2-1.

To adequately wet the containment surface, the water is delivered to the distribution bucket above the center of the containment dome which subsequently delivers the water to the containment surface. A weir-type water distribution system is used on the dome surface to distribute the water for effective wetting of the dome and vertical sides of the containment shell. The weir system contains radial arms and weirs located considering the effects of tolerances of the containment vessel design and construction. A corrosion-resistant paint or coating for the containment vessel is specified to enhance surface wetability and film formation.

The cooling water not evaporated from the vessel wall flows down to the bottom of the inner containment annulus into annulus drains. The redundant annulus drains route the excess water out of the upper annulus. The annulus drains are located in the shield building wall slightly above the floor level to minimize the potential for clogging of the drains by debris. The drains are horizontal or have a slight slope to promote drainage. The drains are always open (without isolation valves) and each is sized to accept maximum passive containment cooling system flow. The outside ends of the drains are located above catch basins or other storm drain collectors.

A path for the natural circulation of air upward along the outside walls of the containment structure is always open. The natural circulation air flow path begins at the shield building inlet, where atmospheric air enters horizontally through openings in the concrete structure. Air flows past a set of fixed louvers and is forced to turn 90 degrees downward into an outer annulus. This outer shield building annulus is encompassed by the concrete shield building on the outside and a removable baffle on the inside. At the bottom of the baffle wall, curved vanes aid in turning the flow upward 180 degrees into the inner containment annulus. This inner annulus is encompassed by the baffle wall on the outside and the steel containment vessel on the inside. Air flows up through the inner annulus to the top of the containment vessel and then exhausts through the shield building chimney.

As the containment structure heats up in response to high containment temperature, heat is removed from within the containment via conduction through the steel containment vessel, convection from the containment surface to the water film, convection and evaporation from the water film to the air, and radiation from the water film to the air baffle. As heat and water vapor are transferred to the air space between the containment structure and air baffle, the air becomes less dense than the air in the outer annulus. This density difference causes an increase in the natural circulation of the air upward between the containment structure and the air baffle, with the air finally exiting at the top center of the shield building.

The passive containment cooling water storage tank provides water for containment wetting for at least 72 hours following system actuation. Operator action can be taken to replenish this water supply from the passive containment cooling ancillary water storage tank or to provide an alternate water source directly to the containment shell through an installed safety-related seismic piping connection. In addition, water sources used for normal filling operations can be used to replenish the water supply.

The arrangement of the air inlet and air exhaust in the shield building structure has been selected so that wind effects aid the natural air circulation. The air inlets are placed at the top, outside of the shield building, providing a symmetrical air inlet that reduces the effect of wind speed and direction or adjacent structures. The air/water vapor exhaust structure is elevated above the air

inlet to provide additional buoyancy and reduces the potential of exhaust air being drawn into the air inlet. The air flow inlet and chimney regions are both designed to protect against ice or snow buildup and to prevent foreign objects from entering the air flow path.

Inadvertent actuation of the passive containment cooling system is terminated through operator action by closing either of the series isolation valves from the main control room. Subsection 6.2.1.1.4 provides a discussion of the effects of inadvertent system actuation.

The passive containment cooling system provides for makeup water to the spent fuel pool to provide for continued spent fuel pool inventory and heat removal. The passive containment cooling water storage tank provides makeup to the spent fuel pool when the inventory is not required for passive containment cooling system operation. An installed long term makeup connection for the passive containment cooling system and the spent fuel pool is provided as a part of the passive containment cooling system. The passive containment cooling ancillary water storage tank and the passive containment cooling system recirculation pumps may also be utilized for makeup to the spent fuel pool.

6.2.2.3 Safety Evaluation

The safety-related portions of the passive containment cooling system are located within the shield building structure. This building (including the safety-related portions of the passive containment cooling system) is designed to withstand the effects of natural phenomena such as earthquakes, winds, tornadoes, or floods. Components of the passive containment cooling system are designed to withstand the effects of ambient temperature extremes.

The portions of the passive containment cooling system which provide for long term (post 72-hour) water supply for containment wetting are located in Seismic Category I or Seismic Category II structures excluding the passive containment ancillary water storage tank and associated valves located outside of the auxiliary building. The water storage tank and the anchorage for the associated valves are Seismic Category II. The features of these structures which protect this function are analyzed and designed for Category 5 hurricanes including the effects of sustained winds, maximum gusts, and associated wind-borne missiles.

Operation of the containment cooling system is initiated automatically following the receipt of a Hi-2 containment pressure signal. The use of this signal provides for system actuation during transients, resulting in mass and energy releases to containment, while avoiding unnecessary actuations. System actuation requires the opening of any of the three isolation valves, with no other actions required to initiate the post-accident heat removal function since the cooling air flow path is always open. Operation of the passive containment cooling system may also be initiated from the main control room and from the remote shutdown workstation. A description of the actuation system is contained in Section 7.3.

The active components of the passive containment cooling system, the isolation valves, are located in three redundant pipe lines. Failure of a component in one train does not affect the operability of the other mechanical train or the overall system performance. The fail-open, air-operated valves require no electrical power to move to their safe (open) position. The normally open motor-operated valves are powered from separate redundant Class 1E dc power sources.

Table 6.2.2-3 presents a failure modes and effects analysis of the passive containment cooling system.

Capability is provided to periodically test actuation of the passive containment cooling system. Active components can be tested periodically during plant operation to verify operability. The system can be inspected during unit shutdown. Additional information is contained in subsections 3.9.6 and 6.2.2.4, as well as in the Technical Specifications.

The passive containment cooling system components located inside containment, the containment pressure sensors, are tested and qualified to perform in a simulated design basis accident environment. These components are protected from effects of postulated jet impingement and pipe whip in case of a high-energy line break.

The containment pressure analyses are based on an ambient air temperature of 115°F dry bulb and 80°F coincident wet bulb. The passive containment cooling water storage tank water temperature basis is 120°F. Results of the analyses are provided in subsection 6.2.1.

6.2.2.4 Testing and Inspection

6.2.2.4.1 Inspections

The passive containment cooling system is designed to permit periodic testing of system readiness as specified in the Technical Specifications.

The portions of the passive containment cooling system from the isolation valves to the passive containment cooling water storage tank are accessible and can be inspected during power operation or shutdown for leaktightness. Examination and inspection of the pressure retaining piping welds is performed in accordance with ASME Code, Section XI. The design of the containment vessel and air baffle retains provisions for the inspection of the vessel during plant shutdowns.

6.2.2.4.2 Preoperational Testing

Preoperational testing of the passive containment cooling system is verified to provide adequate cooling of the containment. The flow rates are confirmed at the minimum initial tank level, an intermediate step with all but one standpipe delivering flow and at a final step with all but two standpipes delivering to the containment shell. The flow rates are measured utilizing the differential pressure across the orifices within each standpipe and will be consistent with the flow rates specified in Table 6.2.2-1.

The containment coverage will be measured at the base of the upper annulus in addition to the coverage at the spring line for the full flow case using the PCS water storage tank delivering to the containment shell and a lower flow case with both PCS recirculation pumps delivering to the containment shell. For the low flow case, a throttle valve is used to obtain a low flow rate less than the full capacity of the PCS recirculation pumps. This flow rate is then re-established for subsequent tests using the throttle valve. These benchmark values will be used to develop acceptance criteria for the Technical Specifications. The full flow condition is selected since it is

the most important flow rate from the standpoint of peak containment pressure and the lower flow rate is selected to verify wetting characteristics at less than full flow conditions.

The standpipe elevations are verified to be at the values specified in Table 6.2.2-2.

The inventory within the tank is verified to provide 72 hours of operation from the minimum initial operating water level with a minimum flow rate over the duration in excess of 100.7 gpm. The flow rates are measured utilizing the differential pressure across the orifices within each standpipe.

The containment vessel exterior surface is verified to be coated with an inorganic zinc coating.

The passive containment cooling air flow path will be verified at the following locations:

- Air inlets
- Base of the outer annulus
- Base of the inner annulus
- Discharge structure

With either a temporary water supply or the passive containment cooling ancillary water storage tank connected to the suction of the recirculation pumps and with either of the two pumps operating, the flow rate to the passive containment cooling water storage tank will be in excess of 100 gpm. Temporary instrumentation or changes in the passive containment cooling water storage tank level will be utilized to verify the flow rates. The capacity of the passive containment cooling ancillary water storage tank is verified to be adequate to supply 135 gpm for a duration of 4 days (100 gpm for passive containment cooling, and 35 gpm for spent fuel pool cooling).

The passive containment cooling water storage tank provides makeup water to the spent fuel pool. When aligned to the spent fuel pool the flow rate is verified to exceed 118 gpm. Installed instrumentation will be utilized to verify the flow rate. The volume of the passive containment cooling water storage tank is verified to exceed the minimum usable volume defined in Table 6.2.2-2. The passive containment cooling ancillary water storage tank recirculation pumps can provide makeup to the spent fuel pool. The flow rate is verified to exceed 35 gpm to the spent fuel pool.

Additional details for preoperational testing of the passive containment cooling system are provided in Chapter 14.

6.2.2.4.3 Operational Testing

Operational testing is performed to:

- Demonstrate that the sequencing of valves occurs on the initiation of Hi-2 containment pressure and demonstrate the proper operation of remotely operated valves.

- Verify valve operation during plant operation. The normally open motor-operated valves, in series with each normally closed air-operated isolation valve, are temporarily closed. This

closing permits isolation valve stroke testing without actuation of the passive containment cooling system.

- Verify water flow delivery and containment water coverage, consistent with the accident analysis.

- Verify visually that the path for containment cooling air flow is not obstructed by debris or foreign objects.

- Test frequency is consistent with the plant technical specifications (subsection 16.3.6) and inservice testing program (subsection 3.9.6).

6.2.2.5 Instrumentation Requirements

The status of the passive containment cooling system is displayed in the main control room. The operator is alerted to problems with the operation of the equipment within this system during both normal and post-accident conditions.

Normal operation of the passive containment cooling system is demonstrated by monitoring the recirculation pump discharge pressure, flow rate, water storage tank levels and temperatures, and valve room temperature. Post-accident operation of the passive containment cooling system is demonstrated by monitoring the passive containment cooling water storage tank level, passive containment cooling system cooling water flow rate, containment pressure and external cooling air discharge temperature.

The information on the activation signal-generating equipment is found in Chapter 7.

The protection and safety monitoring system providing system actuation is discussed in Chapter 7.

6.2.3 Containment Isolation System

The major function of the containment isolation system of the AP1000 is to provide containment isolation to allow the normal or emergency passage of fluids through the containment boundary while preserving the integrity of the containment boundary, if required. This prevents or limits the escape of fission products that may result from postulated accidents. Containment isolation provisions are designed so that fluid lines which penetrate the primary containment boundary are isolated in the event of an accident. This minimizes the release of radioactivity to the environment.

The containment isolation system consists of the piping, valves, and actuators that isolate the containment. The design of the containment isolation system satisfies the requirements of NUREG 0737, as described in the following paragraphs.

6.2.3.1 Design Basis

6.2.3.1.1 Safety Design Basis

A. The containment isolation system is protected from the effects of natural phenomena, such as earthquakes, tornadoes, hurricanes, floods, and external missiles (General Design Criterion 2).

B. The containment isolation system is designed to remain functional after a safe shutdown earthquake (SSE) and to perform its intended function following the postulated hazards of fire, internal missiles, or pipe breaks (General Design Criteria 3 and 4).

C. The containment isolation system is designed and fabricated to codes consistent with the quality group classification, described in Section 3.2. Conformance with Regulatory Guide 1.26, 1.29, and 1.32 is described in subsection 1.9.

D. The containment isolation system provides isolation of lines penetrating the containment for design basis events requiring containment integrity.

E. Upon failure of a main steam line, the containment isolation system isolates the steam generators as required to prevent excessive cooldown of the reactor coolant system or overpressurization of the containment.

F. The containment isolation system is designed in accordance with General Design Criterion 54.

G. Each line that penetrates the containment that is either a part of the reactor coolant pressure boundary or that connects directly to the containment atmosphere, and does not meet the requirements for a closed system (as defined in paragraph H below), is provided with containment isolation valves according to General Design Criteria 55 and 56.

H. Each line that penetrates the containment, that is neither part of the reactor coolant pressure boundary nor connected directly to the atmosphere of the containment, and that satisfies the requirements of a closed system is provided with a containment isolation valve according to General Design Criterion 57. A closed system is not a part of the reactor coolant pressure boundary and is not connected directly to the atmosphere of the containment. A closed system also meets the following additional requirements:

- The system is protected against missiles and the effects of high-energy line break.
- The system is designed to Seismic Category I requirements.
- The system is designed to ASME Code, Section III, Class 2 requirements.
- The system is designed to withstand temperatures at least equal to the containment design temperature.

- The system is designed to withstand the external pressure from the containment structural acceptance test.
- The system is designed to withstand the design basis accident transient and environment.

I. The containment isolation system is designed so that no single failure in the containment isolation system prevents the system from performing its intended functions.

J. Fluid penetrations supporting the engineered safety features functions have remote manual isolation valves. These valves can be closed from the main control room or from the remote shutdown workstation, if required.

K. The containment isolation system is designed according to 10 CFR 50.34, so that the resetting of an isolation signal will not cause any valve to change position.

6.2.3.1.2 Power Generation Design Basis

The containment isolation system has no power generation design basis. Power generation design bases associated with individual components of the containment isolation system are discussed in the section describing the system of which they are an integral part.

6.2.3.1.3 Additional Requirements

The AP1000 containment isolation system is designed to meet the following additional requirements:

A. The containment isolation elements are designed to minimize the number of isolation valves which are subject to Type C tests of 10 CFR 50, Appendix J. Specific requirements are the following:

- The number of pipe lines which provide a direct connection between the inside and outside of primary containment during normal operation are minimized.
- Closed systems outside of containment that may be open to the containment atmosphere during an accident are designed for the same conditions as the containment itself, and are testable during Type A leak tests.
- The total number of penetrations requiring isolation valves are minimized by appropriate system design. For example:
  - In the component cooling system, a single header with branch lines inside of containment is employed instead of providing a separate penetration for each branch line.
  - Consistent with other considerations, such as containment arrangement and exposure of essential safety equipment to potentially harsh environments, the

equipment is located inside and outside of containment so as to require the smallest number of penetrations.

- Consistent with current practice, Type C testing is not required for pressurized water reactor main steam, feedwater, startup feedwater, or steam generator blowdown isolation valves. The steam generator tubes are considered to be a suitable boundary to prevent release of radioactivity from the reactor coolant system following an accident. The steam generator shell and pipe lines, up to and including the first isolation valve, are considered a suitable boundary to prevent release of containment radioactivity.

B. Personnel hatches, equipment hatches, and the fuel transfer tube are sealed by closures with double gaskets.

C. Containment isolation is actuated on a two-out-of-four logic from within the protection and safety monitoring system. The safeguards signals provided to each isolation valve are selected to enhance plant safety. Provisions are provided for manual containment isolation from the main control room.

D. Penetration lines with automatic isolation valves are isolated by engineered safety features actuation signals.

E. Isolation valves are designed to provide leaktight service against the medium to which the valves are exposed in the short and long-term course of any accident. For example, a valve is gas-tight if the valve is exposed to the containment atmosphere.

F. Isolation valves are designed to have the capacity to close against the conditions that may exist during events requiring containment isolation.

G. Isolation valve closure times are designed to limit the release of radioactivity to within regulation and are consistent with standard valve operators, except where a shorter closure time is required.

H. The position of each power-operated isolation valve (fully closed or open), whether automatic or remote manual, is indicated in the main control room and is provided as input to the plant computer. Such position indication is based on actual valve position, for example, by a limit switch which directly senses the actual valve stem position, rather than demanded valve position.

I. Normally closed manual containment isolation valves have provisions for locking the valves closed. Locking devices are designed such that the valves can be locked only in the fully closed position. Administrative control provides verification that manual isolation valves are maintained locked closed during normal operation. Position locks provide confidence that valves are placed in the correct position prior to locking.

J. Automatic containment isolation valves are powered by Class 1E dc power. Air-operated valves fail in the closed position upon loss of a support system, such as instrument air or electric power.

K. Valve alignments used for fluid system testing during operation are designed so that either: containment bypass does not occur during testing, assuming a single failure; or exceptions are identified, and remotely operated valves provide timely isolation from the control room. Containment isolation provisions can be relaxed during system testing. The intent of the design is to provide confidence that operators are aware of any such condition and have the capability to restore containment integrity.

L. A diverse method of initiating closure is provided for those containment isolation valves associated with penetrations representing the highest potential for containment bypass. Diverse actuation is discussed in Section 7.7.

M. Containment penetrations with leaktight barriers, both inboard and outboard, are designed to limit pressure excursion between the barriers due to heatup of fluid between the barriers. The penetration will either be fitted with relief or check valves to relieve internal pressure or one of the valves has been designed or oriented to limit pressures to an acceptable value. For example, a penetration which incorporates two air-operated globe valves – one of the globe valves will be oriented such that pressure between the two valves will lift the plug from the seat to relieve the pressure, then reseat.

6.2.3.2 System Description

6.2.3.2.1 General Description

Piping systems penetrating the containment have containment isolation features. These features serve to minimize the release of fission products following a design basis accident. SRP Section 6.2.4 provides acceptable alternative arrangements to the explicit arrangements given in General Design Criteria 55, 56 and 57. Table 6.2.3-1 lists each penetration and provides a summary of the containment isolation characteristics. The Piping and Instrumentation Diagrams of the applicable systems show the functional arrangement of the containment penetration, isolation valves, test and drain connections. Section 1.7 contains a list of the Piping and Instrumentation Diagrams.

As discussed in subsection 6.2.3.1, the AP1000 containment isolation design satisfies the NRC requirements including post-Three Mile Island requirements. Two barriers are provided -- one inside containment and one outside containment. Usually these barriers are valves, but in some cases they are closed piping systems not connected to the reactor coolant system or to the containment atmosphere.

The AP1000 has fewer mechanical containment penetrations (including hatches) and a higher percentage of normally closed isolation valves than current plants. The majority of the penetrations that are normally open incorporate fail closed isolation valves that close automatically with the loss of support systems such as instrument air. Table 6.2.3-1 lists the AP1000 containment mechanical penetrations and the isolation valves associated with them. Provisions for leak testing are discussed in subsection 6.2.5.

For those systems having automatic isolation valves or for those provided with remote-manual isolation, subsection 6.2.3.5 describes the power supply and associated actuation system.

Power-operated (air, motor, or pneumatic) containment isolation valves have position indication in the main control room.

The actuation signal that occurs directly as a result of the event initiating containment isolation is designated in Table 6.2.3-1. If a change in valve position is required at any time following primary actuation, a secondary actuation signal is generated which places the valve in an alternative position. The closure times for automatic containment isolation valves are provided in Table 6.2.3-1.

The containment air filtration system is used to purge the containment atmosphere of airborne radioactivity during normal plant operation, as described in subsection 9.4.7. The system is designed in accordance with Branch Technical Position CSB 6-4 using 16-inch supply and exhaust lines and containment isolation valves. These valves close automatically on a containment isolation signal.

Section 3.6 describes dynamic effects of pipe rupture. Section 3.5 discusses missile protection, and Section 3.8 discusses the design of Category I structures including any structure used as a protective device. Lines associated with those penetrations that are considered closed systems inside the containment are protected from the effects of a pipe rupture and missiles. The actuators for power-operated isolation valves inside the containment are either located above the maximum containment water level or in a normally nonflooded area. The actuators are designed for flooded operation or are not required to function following containment isolation and designed and qualified not to spuriously open in a flooded condition.

Other defined bases for containment isolation are provided in SRP Section 6.2.4.

6.2.3.2.2 Component Description

Codes and standards applicable to the piping and valves associated with containment isolation are those for Class B components, as discussed in Section 3.2. Containment penetrations are classified as Quality Group B and Seismic Category I.

Section 3.11 provides the normal, abnormal, and post-loss-of-coolant accident environment that is used to qualify the operability of power-operated isolation valves located inside the containment.

The containment penetrations which are part of the main steam system and the feedwater system are designed to meet the stress requirements of NRC Branch Technical Position MEB 3-1, and the classification and inspection requirements of NRC Branch Technical Position ASB 3-1, as described in Section 3.6. Section 3.8 discusses the interface between the piping system and the steel containment.

As discussed in subsection 6.2.3.5, the instrumentation and control system provides the signals which determine when containment isolation is required. Containment penetrations are either normally closed prior to the isolation signal or the valves automatically close upon receipt of the appropriate engineered safety features actuation signal.

6.2.3.2.3 System Operation

During normal system operation, approximately 25 percent of the penetrations are not isolated. These lines are automatically isolated upon receipt of isolation signals, as described in subsections 6.2.3.3 and 6.2.3.4 and Chapter 7. Lines not in use during power operation are normally closed and remain closed under administrative control during reactor operation.

6.2.3.3 Design Evaluation

A. Engineered safeguards and containment isolation signals automatically isolate process lines which are normally open during operation. The containment isolation system uses diversity in the parameters sensed for the initiation of redundant train-oriented isolation signals. The majority of process lines are closed upon receipt of a containment isolation signal. This safeguards signal is generated by any of the following initiating conditions.

- Low pressurizer pressure
- Low steam-line pressure
- Low T_{cold}
- High containment pressure
- Manual containment isolation actuation

The component cooling water lines penetrating containment provide cooling water to the reactor coolant pumps and chemical and volume control system and liquid radwaste system heat exchangers. The reactor coolant pumps are interlocked to trip following a safeguards actuation (S) signal but will continue to operated (if in service) following a containment isolation (T) signal. In order to provide reliable cooling to the reactor coolant pumps the component cooling lines are isolated on a safeguards actuation signal rather than on a containment isolation signal. The safeguards actuation signal is generated by any of the following conditions.

- Low pressurizer pressure
- Low steam line pressure
- Low reactor coolant inlet temperature
- High containment pressure
- Manual initiation

The chemical and volume control system charging line, normal residual heat removal system reactor coolant and IRWST cooling lines, and containment air filtration system containment purge lines are isolated on high containment radiation signals. Closure of the containment air filtration system isolation valves is based on providing rapid response to elevated activity conditions in containment to limit offsite doses and is initiated on either a high radiation signal or a containment isolation signal consistent with the requirements of NUREG-0737 (Reference 22) and NUREG-0718 Rev 2 (Reference 23). The isolation of the chemical and volume control system charging line on a high radiation signal and normal residual heat removal system cooling lines on a high radiation or safeguards actuation signal with provisions to reset safeguards actuation signal for the normal residual heat removal system valves permits a defense in depth response to a postulated accident by providing for normal

residual heat removal system and chemical and volume control system operation unless there is a high radiation level present.

The remainder of the containment isolation valves are closed on parameters indicative of the need to isolate.

B. Upon failure of a main steam line, the steam generators are isolated, and the main steam-line isolation valves, main steam-line isolation bypass valves, power operated relief block valves, and the main steam-line drain are closed to prevent excessive cooldown of the reactor coolant system or overpressurization of the containment.

The two redundant train-oriented steam-line isolation signals are initiated upon receipt of any of the following signals:

- Low steam-line pressure
- High steam pressure negative rate
- High containment pressure
- Manual actuation
- Low T_{cold}

The main steam-line isolation valves, main steam line isolation valve bypass valves, main feedwater isolation valves, steam generator blowdown system isolation valves, and piping are designed to prevent uncontrolled blowdown from more than one steam generator. The main steam-line isolation valves and main feedwater isolation valves close fully within 5 seconds after an isolation is initiated. The blowdown rate is restricted by steam flow restrictors located within the steam generator outlet steam nozzles in each blowdown path. For main steam-line breaks upstream of an isolation valve, uncontrolled blowdown from more than one steam generator is prevented by the main steam-line isolation valves on each main steam line.

Failure of any one of these components relied upon to prevent uncontrolled blowdown of more than one steam generator does not permit a second steam generator blowdown to occur. No single active component failure results in the failure of more than one main steam isolation valve to operate. Redundant main steam isolation signals, described in Section 7.3, are fed to redundant parallel actuation vent valves to provide isolation valve closure in the event of a single isolation signal failure.

The effects on the reactor coolant system after a steam-line break resulting in single steam generator blowdown and the offsite radiation exposure after a steam line break outside containment are discussed in Chapter 15. The containment pressure transient following a main steam-line break inside containment is discussed in Section 6.2.

C. The containment isolation system is designed according to General Design Criterion 54. Leakage detection capabilities and leakage detection test program are discussed in subsection 6.2.5. Valve operability tests are also discussed in subsection 3.9.6. Redundancy of valves and reliability of the isolation system are provided by the other safety design bases

stated in Section 6.2. Redundancy and reliability of the actuation system are covered in Section 7.3.

The use of motor-operated valves that fail as-is upon loss of actuating power in lines penetrating the containment is based upon the consideration of what valve position provides the plant safety. Furthermore, each of these valves, is provided with redundant backup valves to prevent a single failure from disabling the isolation function. Examples include: a check valve inside the containment and motor-operated valve outside the containment or two motor-operated valves in series, each powered from a separate engineered safety features division.

D. Lines that penetrate the containment and which are either part of the reactor coolant pressure boundary, connect directly to the containment atmosphere, or do not meet the requirements for a closed system are provided with one of the following valve arrangements conforming to the requirements of General Design Criteria 55 and 56, as follows:

- One locked-closed isolation valve inside and one locked-closed isolation valve outside containment
- One automatic isolation valve inside and one locked-closed isolation valve outside containment
- One locked-closed isolation valve inside and one automatic isolation valve outside containment. (A simple check valve is not used as the automatic isolation valve outside containment.)
- One automatic isolation valve inside and one automatic isolation valve outside containment. (A simple check valve is not used as the automatic isolation valve outside containment).

Isolation valves outside containment are located as close to the containment as practical. Upon loss of actuating power, air-operated automatic isolation valves fail closed.

E. Each line penetrating the containment that is neither part of the reactor coolant pressure boundary nor connected directly to the containment atmosphere, and that satisfies the requirements of a closed system, has at least one containment isolation valve. This containment isolation valve is either automatic, locked-closed, or capable of remote-manual operation. The valve is outside the containment and located as close to the containment as practical. A simple check valve is not used as the automatic isolation valve. This design is in compliance with General Design Criterion 57.

F. The containment isolation system is designed according to seismic Category I requirements as specified in Section 3.2. The components (and supporting structures) of any system, equipment, or structure that are non-seismic and whose collapse could result in loss of a required function of the containment isolation system through either impact or resultant flooding are evaluated to confirm that they will not collapse when subjected to seismic loading resulting from a safe shutdown earthquake.

Air-operated isolation valves fail in the closed position upon loss of air or power. Containment isolation system valves required to be operated after a design basis accident or safe shutdown earthquake are powered by the Class 1E dc electric power system.

6.2.3.4 Tests and Inspections

6.2.3.4.1 Preoperational Testing

Preoperational testing is described in Chapter 14. The containment isolation system is testable through the operational sequence that is postulated to take place following an accident, including operation of applicable portions of the protection system and the transfer between normal and standby power sources.

The safety related function of containment boundary integrity is verified by an integrated leakage rate test. The integrated leakage rate is verified to be less than L_a as defined in Table 6.5.3-1. The integrated containment leakage rate system is utilized to measure the containment leak rate for determination of the integrated leakage rate. The containment isolation valves are verified to close within the time specified in Table 6.2.3-1.

The piping and valves associated with the containment penetration are designed and located to permit pre-service and in-service inspection according to ASME Section XI, as discussed in subsection 3.9.6 and Section 6.6.

6.2.3.4.2 In-service Testing

Each line penetrating the containment is provided with testing features to allow containment leak rate tests according to 10 CFR 50, Appendix J, as discussed in subsection 6.2.5.

6.2.3.5 Instrumentation and Control Application

Instrumentation and control necessary for containment isolation, and the sensors used to determine that containment isolation is required, are described in Section 7.3.

Engineered safeguards actuation signals which initiate containment isolation will be initiated using two out of four logic. Containment isolation signals can also be initiated manually from the main control room. Containment isolation valves requiring isolation close automatically on receipt of a safeguards actuation signal.

Containment isolation valves that are equipped with power operators and are automatically actuated may also be controlled individually from the main control room. Also, in the case of certain valves with actuators (for example, sampling containment isolation valves), a manual override of an automatic isolation signal is installed to permit manual control of the associated valve. The override control function can be performed only subsequent to resetting of the actuation signal. That is, deliberate manual action is required to change the position of containment isolation valves in addition to resetting the original actuation signal. Resetting of the actuation signal does not cause any valve to change position. The design does not allow ganged reopening of the containment isolation valves. Reopening of the isolation valves is performed on a valve-by-valve basis, or on a line-by-line basis. Safeguards actuation signals take precedence over

manual overrides of other isolation signals. For example, a containment isolation signal causes isolation valve closure even though the high containment radiation signal is being overridden by the operator. Containment isolation valves with power operators are provided with open/closed indication, which is displayed in the main control room. The valve mechanism also provides a local mechanical indication of valve position.

Power supplies and control functions necessary for containment isolation are Class 1E, as described in Chapters 7 and 8.

6.2.4 Containment Hydrogen Control System

The containment hydrogen control system is provided to limit the hydrogen concentration in the containment so that containment integrity is not endangered.

Following a severe accident, it is assumed that 100 percent of the fuel cladding reacts with water. Although hydrogen production due to radiolysis and corrosion occurs, the cladding reaction with water dominates the production of hydrogen for this case. The hydrogen generation from the zirconium-steam reaction could be sufficiently rapid that it may not be possible to prevent the hydrogen concentration in the containment from exceeding the lower flammability limit. The function of the containment hydrogen control system for this case is to promote hydrogen burning soon after the lower flammability limit is reached in the containment. Initiation of hydrogen burning at the lower level of hydrogen flammability prevents accidental hydrogen burn initiation at high hydrogen concentration levels and thus provides confidence that containment integrity can be maintained during hydrogen burns and that safety-related equipment can continue to operate during and after the burns.

The containment hydrogen control system serves the following functions:

- Hydrogen concentration monitoring
- Hydrogen control during and following a degraded core or core melt scenarios (provided by hydrogen igniters). In addition, two nonsafety related passive autocatalytic recombiners (PARs) are provided for defense-in-depth protection against the buildup of hydrogen following a loss of coolant accident.

6.2.4.1 Design Basis

A. The hydrogen control system is designed to provide containment atmosphere cleanup (hydrogen control) in accordance with General Design Criterion 41, 42 and 43.

B. The hydrogen control system is designed in accordance with the requirements of 10 CFR 50.44 and 10 CFR 50.34(f) and meets the NRC staff's position related to hydrogen control of SECY-93-087.

C. The hydrogen control system is designed in compliance with the recommendations of NUREG 0737 and 0660 as detailed in subsection 1.9.

D. The hydrogen control system is designed in accordance with the recommendations of Regulatory Guide 1.7 as discussed in appendix 1A. The containment recirculation system discussed in subsection 9.4.7 provides the controlled purge capability for the containment as specified in position C.4 of Regulatory Guide 1.7

E. The hydrogen control system is designed and fabricated to codes consistent with the quality group classification, described in Section 3.2. Conformance with Regulatory Guide 1.26, 1.29, and 1.32 is described in subsection 1.9.

F. The hydrogen control system complies with the intent of Regulatory Guide 1.82 “The Water Sources For Long-Term Recirculation Cooling Following A Loss-Of-Coolant Accident” as it could be applied to concerns for blockage of recombiner air flow paths.

6.2.4.1.1 Containment Mixing

Containment structures are arranged to promote mixing via natural circulation. The physical mechanisms of natural circulation mixing that occur in the AP1000 are discussed in Appendix 6A and summarized below. For a postulated break low in the containment, buoyant flows develop through the lower compartments due to density head differences between the rising plume and the surrounding containment atmosphere, tending to drive mixing through lower compartments and into the region above the operating deck. There is also a degree of mixing within the region above the operating deck, which occurs due to the introduction of and the entrainment into the steam-rich plume as it rises from the operating deck openings. Thus, natural forces tend to mix the containment atmosphere.

Two general characteristics have been incorporated into the design of the AP1000 to promote mixing and eliminate dead-end compartments. The compartments below deck are large open volumes with relatively large interconnections, which promote mixing throughout the below deck region. All compartments below deck are provided with openings through the top of the compartment to eliminate the potential for a dead pocket of high-hydrogen concentration. In addition, if forced containment air-circulation is operated during post-accident recovery, then nonsafety-related fan coolers contribute to circulation in containment.

In the event of a hydrogen release to the containment, passive autocatalytic recombiners act to recombine hydrogen and oxygen on a catalytic surface (see subsection 6.2.4.2.2). The enthalpy of reaction generates heat within a passive autocatalytic recombiner, which further drives containment mixing by natural circulation. Catalytic recombiners reduce hydrogen concentration at very low hydrogen concentrations (less than 1 percent) and very high steam concentrations, and may also promote convection to complement passive containment cooling system natural circulation currents to inhibit stratification of the containment atmosphere (Reference 17). The implementation of passive autocatalytic recombiners has a favorable impact on both containment mixing and hydrogen mitigation.

6.2.4.1.4 Validity of Hydrogen Monitoring

The hydrogen monitoring function monitors hydrogen concentrations of various locations within the containment.

6.2.4.1.5 Hydrogen Control for Severe Accident

The containment hydrogen concentration is limited by operation of the distributed hydrogen ignition subsystem. Ignition causes deflagration of hydrogen (burning of the hydrogen with flame front propagation at subsonic velocity) at hydrogen concentrations between the flammability limit and 10 volume percent and thus prevents the occurrence of hydrogen detonation (burning of hydrogen with supersonic flame front propagation).

6.2.4.2 System Design

6.2.4.2.1 Hydrogen Concentration Monitoring Subsystem

The hydrogen concentration monitoring subsystem consists of three hydrogen sensors. The sensors are placed in the upper dome where bulk hydrogen concentration can be monitored.

The system contains a total of three sensors designated as non-Class 1E serving to provide a post accident monitoring function. See Section 7.5 for additional information.

The hydrogen sensors are powered by the Non-Class 1E dc and UPS System. Sensor parameters are provided in Table 6.2.4-1. Hydrogen concentration is continuously indicated in the main control room. Additionally, high hydrogen concentration alarms are provided in the main control room.

The sensors are designed to provide a rapid response detection of changes in the bulk containment hydrogen concentration.

6.2.4.2.2 Hydrogen Recombination Subsystem

The hydrogen recombination subsystem is designed to accommodate the hydrogen production rate anticipated for loss of coolant accident. The hydrogen recombination subsystem consists of two nonsafety-related passive autocatalytic recombiners installed inside the containment above the operating deck at approximate elevations of 162 feet and 166 feet respectively, each about 13 feet inboard from the containment shell. The locations provide placement within a homogeneously mixed region of containment as supported by subsection 6.2.4.1.1 and Appendix 6A. The location is in a predominately upflow natural convection region. Additionally, the PARs are located azimuthally away from potential high upflow regions such as the direct plume above the loop compartment.

The passive autocatalytic recombiners are simple and passive in nature without moving parts and independent of the need for electrical power or any other support system. The recombiners require no power supply and are self-actuated by the presence of the reactants (hydrogen and oxygen).

Normally, oxygen and hydrogen recombine by rapid burning only at elevated temperatures (greater than about 1100°F [600°C]). However, in the presence of catalytic materials such as the palladium group, this “catalytic burning” occurs even at temperatures below 32°F (0°C). Adsorption of the oxygen and hydrogen molecules occurs on the surface of the catalytic metal because of attractive forces of the atoms or molecules on the catalyst surface. Passive autocatalytic recombiner devices use palladium or platinum as a catalyst to combine molecular hydrogen with

oxygen gases into water vapor. The catalytic process can be summarized by the following steps (Reference 15):

1. Diffusion of the reactants (oxygen and hydrogen) to the catalyst
2. Reaction of the catalyst (chemisorption)
3. Reaction of intermediates to give the product (water vapor)
4. Desorption of the product
5. Diffusion of the product away from the catalyst

The reactants must get to the catalyst before they can react and subsequently the product must move away from the catalyst before more reactants will be able to react.

The passive autocatalytic recombiner device consists of a stainless steel enclosure providing both the structure for the device and support for the catalyst material. The enclosure is open on the bottom and top and extends above the catalyst elevation to provide a chimney to yield additional lift to enhance the efficiency and ventilation capability of the device. The catalyst material is either constrained within screen cartridges or deposited on a metal plate substrate material and supported within the enclosure. The spaces between the cartridges or plates serve as ventilation channels for the throughflow. During operation, the air inside the recombiner is heated by the recombination process, causing it to rise by natural convection. As it rises, replacement air is drawn into the recombiner through the bottom of the passive autocatalytic recombiner and heated by the exothermic reaction, forming water vapor, and exhausted through the chimney where the hot gases mix with containment atmosphere. The device is a molecular diffusion filter and thus the open flow channels are not susceptible to fouling.

Passive autocatalytic recombiners begin the recombination of hydrogen and oxygen almost immediately upon exposure to these gases when the catalyst is not wetted. If the catalyst material is wet, then a short delay is experienced in passive autocatalytic recombiner startup (References 19 and 29). The delay is short with respect to the time that the PARs have to control hydrogen accumulation rates (days to weeks) following a design basis accident. The recombination process occurs at room or elevated temperature during the early period of accidents prior to the buildup of flammable gas concentrations. Passive autocatalytic recombiners are effective over a wide range of ambient temperatures, concentrations of reactants (rich and lean, oxygen/hydrogen less than 1 percent) and steam inerting (steam concentrations greater than 50 percent). Although the passive autocatalytic recombiner depletion rate reaches peak efficiency within a short period of time, the rate varies with hydrogen concentration and containment pressure, (Reference 19).

Passive autocatalytic recombiners have been shown to be effective at minimizing the buildup of hydrogen inside containment following loss of coolant accidents (Reference 16). They are provided in the AP1000 as defense-in-depth protection against the buildup of hydrogen following a loss of coolant accident. A summary of component data for the hydrogen recombiners is provided in Table 6.2.4-2.

6.2.4.2.3 Hydrogen Ignition Subsystem

The hydrogen ignition subsystem is provided to address the possibility of an event that results in a rapid production of large amounts of hydrogen such that the rate of production exceeds the

capacity of the recombiners. Consequently, the containment hydrogen concentration will exceed the flammability limits. This massive hydrogen production is postulated to occur as the result of a degraded core or core melt accident (severe accident scenario) in which up to 100 percent of the zirconium fuel cladding reacts with steam to produce hydrogen.

The hydrogen ignition subsystem consists of 64 hydrogen igniters strategically distributed throughout the containment. Since the igniters are incorporated in the design to address a low-probability severe accident, the hydrogen ignition system is not Class 1E. Although not class 1E, the igniter coverage, distribution and power supply has been designed to minimize the potential loss of igniter protection globally for containment and locally for individual compartments. The igniters have been divided into two power groups. Power to each group will be normally provided by offsite power, however should offsite power be unavailable, then each of the power groups is powered by one of the onsite non-essential diesels and finally should the diesels fail to provide power then approximately 4 hours of igniter operation is supported by the non-Class 1E batteries for each group. Assignment of igniters to each group is based on providing coverage for each compartment or area by at least one igniter from each group.

The locations of the igniters are based on evaluation of hydrogen transport in the containment and the hydrogen combustion characteristics. Locations include compartmented areas in the containment and various locations throughout the free volume, including the upper dome.

For enclosed areas of the containment at least two igniters are installed. The separation between igniter locations is selected to prevent the velocity of a flame front initiated by one igniter from becoming significant before being extinguished by a similar flame front propagating from another igniter. The number of hydrogen igniters and their locations are selected considering the behavior of hydrogen in the containment during severe accidents. The likely hydrogen transport paths in the containment and hydrogen burn physics are the two important aspects influencing the choice of igniter location.

The primary objective of installing an igniter system is to promote hydrogen burning at a low concentration and, to the extent possible, to burn hydrogen more or less continuously so that the hydrogen concentration does not build up in the containment. To achieve this goal, igniters are placed in the major regions of the containment where hydrogen may be released, through which it may flow, or where it may accumulate. The criteria utilized in the evaluation and the application of the criteria to specific compartments is provided in Table 6.2.4-6. The location of igniters throughout containment is provided in Figures 6.2.4-5 through 6.2.4-13. The location of igniters is also summarized in Table 6.2.4-7 identifying subcompartment/regions and which igniters by power group provide protection. The locations identified are considered approximations ($\pm$ 2.5 feet) with the final locations governed by the installation details.

The igniter assembly is designed to maintain the surface temperature within a range of 1600° to 1700°F in the anticipated containment environment following a loss of coolant accident. A spray shield is provided to protect the igniter from falling water drops (resulting from condensation of steam on the containment shell and on nearby equipment and structures). Design parameters for the igniters are provided in Table 6.2.4-3.

6.2.4.2.4 Containment Purge

Containment purge is not part of the containment hydrogen control system. The purge capability of the containment air filtration system (see subsection 9.4.7) can be used to provide containment venting prior to post-loss of coolant accident cleanup operations.

6.2.4.3 Design Evaluation (Design Basis Accident)

A design basis accident evaluation is not required.

6.2.4.4 Design Evaluation (Severe Accident)

Although a severe accident involving major core degradation or core melt is not a design basis accident, the containment hydrogen control system contains design features to address this potential occurrence. The hydrogen monitoring subsystem has sufficient range to monitor concentrations up to 20 percent hydrogen. The hydrogen ignition subsystem is provided so that hydrogen is burned off in a controlled manner, preventing the possibility of deflagration with supersonic flame front propagation which could result in large pressure spikes in the containment.

It is assumed that 100 percent of the active fuel cladding zirconium reacts with steam. This reaction may take several hours to complete. The igniters initiate hydrogen burns at concentrations less than 10 percent by volume and prevent the containment hydrogen concentration from exceeding this limit. Further evaluation of hydrogen control by the igniters is presented in the AP1000 Probabilistic Risk Assessment.

6.2.4.5 Tests and Inspections

6.2.4.5.1 Preoperational Inspection and Testing

Hydrogen Monitoring Subsystem

Pre-operational testing is performed either before or after installation but prior to plant startup to verify performance.

Hydrogen Recombination Subsystem

The performance of the autocatalytic recombiner plates (or cartridges) is tested by the manufacturer for each lot or batch of catalyst material. The number of plates tested is based on the guidance provided in ANSI/ASQC Z1.4-1993, “Sampling Procedures and Tables for Inspection by Attributes,” (formerly Military Standard 105), required to achieve Inspection Level III quality level.

Hydrogen Ignition Subsystem

Pre-operational testing and inspection is performed after installation of the hydrogen ignition system and prior to plant startup to verify operability of the hydrogen igniters. It is verified that 64 igniter assemblies are installed at the locations defined by Figures 6.2.4-5 through 6.2.4-11. Operability of the igniters is confirmed by verification of the surface temperature in excess of the

value specified in Table 6.2.4-3. This temperature is sufficient to ensure ignition of hydrogen concentrations above the flammability limit.

Pre-operational inspection is performed to verify the location of openings through the ceilings of the passive core cooling system valve/accumulator rooms. The primary openings must be at least 19 feet from the containment shell. Primary openings are those that constitute 98% of the opening area. Other openings must be at least 3 feet from the containment shell.

Pre-operational inspection is performed to verify the orientation of the vents from the IRWST that are located along the side of the IRWST next to the containment. The discharge of each of these IRWST vents must be oriented generally away from the containment shell.

6.2.4.5.2 In-service Testing

Hydrogen Monitoring Subsystem

The system is normally in service. Periodic testing and calibration are performed to provide ongoing confirmation that the hydrogen monitoring function can be reliably performed.

Hydrogen Recombination Subsystem

Periodic inspection and testing are performed on the passive autocatalytic recombiners. The testing is performed by testing a sample of the catalyst plates as specified in subsection 6.2.4.5.1.

Hydrogen Ignition Subsystem

Periodic inspection and testing are performed to confirm the continued operability of the hydrogen ignition system. Operability testing consists of energizing the igniters and confirming the surface temperature exceeds the value specified in Table 6.2.4-3.

6.2.4.6 Combined License Information

This section has no requirement to be provided in support of the Combined License application.

6.2.5 Containment Leak Rate Test System

The reactor containment, containment penetrations and isolation barriers are designed to permit periodic leak rate testing in accordance with General Design Criteria 52, 53, and 54. The containment leak rate test system is designed to verify that leakage from the containment remains within limits established in the technical specifications, Chapter 16.

6.2.5.1 Design Basis

Leak rate testing requirements are defined by 10 CFR 50 Appendix J, "Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors," (Reference 14) which classifies leak tests as Types A, B and C. The system design provides testing capability consistent with the testing requirements of ANSI-56.8 (Reference 13). The system design accommodates the test

methods and frequencies consistent with requirements of 10 CFR 50 Appendix J, Option A or Option B.

6.2.5.1.1 Safety Design Basis

The containment leak rate test system serves no safety-related function other than containment isolation, and therefore has no nuclear safety design basis except for containment isolation. See subsection 6.2.3 for the containment isolation system.

6.2.5.1.2 Power Generation Design Basis

The containment leak rate test system is designed to verify the leak tightness of the reactor containment. The specified maximum allowable containment leak rate is 0.10 weight percent of the containment air mass per day at the calculated peak accident pressure, P_a, identified in subsection 6.2.1. The system is specifically designed to perform the following tests in accordance with the provisions of ANSI-56.8 (Reference 13):

- Containment integrated leak rate testing (Type A): The containment is pressurized with clean, dry air to a pressure of P_a. Measurements of containment pressure, dry bulb temperature, and dew point temperature are used to determine the decrease in the mass of air in the containment over time, and thus establish the leak rate.

- Local leak rate testing of containment penetrations with a design that incorporates features such as resilient seals, gaskets, and expansion bellows (Type B): The leakage limiting boundary is pressurized with air or nitrogen to a pressure of P_a and the pressure decay or the leak flow rate is measured.

- Local leak rate testing of containment isolation valves (Type C): The piping test volume is pressurized with air or nitrogen to a pressure of P_a and pressure decay or the leak flow rate is measured. For valves sealed with a fluid such as water, the test volume is pressurized with the seal fluid to a pressure of not less than 1.1 P_a.

The containment leak rate test system piping is also designed for use during the performance of the containment structural integrity test. The instrumentation used for the structural integrity test may be different than that used for the integrated leak rate test.

6.2.5.1.3 Codes and Standards

The containment leak rate test system is designed to conform to the applicable codes and standards listed in Section 3.2. The containment leak testing program satisfies 10 CFR 50, Appendix J requirements.

6.2.5.2 System Description

6.2.5.2.1 General Description

The containment leak rate test system is illustrated on Figure 6.2.5-1. Unless otherwise indicated on the figure, piping and instrumentation is permanently installed. Fixed test connections used for

Type C testing of piping penetrations are not shown on Figure 6.2.5-1. These connections are not part of the containment leak rate test system and are shown on the applicable system piping and instrument diagram figure.

Air compressor assemblies used for Type A testing are temporarily installed and are connected to the permanent system piping. The number and capacity of the compressors is sufficient to pressurize the containment with air to a pressure of P_a at a maximum containment pressurization rate of about 5 psi/hour. The compressor assemblies include additional equipment, such as air coolers, moisture separators and air dryers to reduce the moisture content of the air entering containment.

Temperature and humidity sensors are installed inside containment for Type A testing. Data acquisition hardware and instrumentation is available outside containment. Instrumentation not required during normal plant operation may be installed temporarily for the Type A tests.

The system is designed to permit depressurization of the containment at a maximum rate of 10 psi/hour.

Portable leak rate test panels are used to perform Type C containment isolation valve leak testing using air or nitrogen. The panels are also used for Type B testing of penetrations, for which there is no permanently installed test equipment. The panels include pressure regulators, filters, pressure gauges and flow instrumentation, as required to perform specific tests.

6.2.5.2.2 System Operation

Containment Integrated Leak Rate Test (Type A)

An integrated leak rate test of the primary reactor containment is performed prior to initial plant operation, and periodically thereafter, to confirm that the total leakage from the containment does not exceed the maximum allowable leak rate. The allowable leak rate specified in the test criteria is less than the maximum allowable containment leak rate, in accordance with 10 CFR 50, Appendix J.

Following construction of the containment and satisfactory completion of the structural integrity test, described in subsection 3.8.2.7, a preoperational Type A test is performed as described in Chapter 14. Additional Type A tests are conducted during the plant life, at intervals in accordance with the technical specifications, Chapter 16.

- Pretest Requirements

Prior to performing an integrated leak rate test, a number of pretest requirements must be satisfied as described in this subsection.

A general inspection of the accessible interior and exterior surfaces of the primary containment structure and components is performed to uncover any evidence of structural deterioration that could affect either the containment structural integrity or leak tightness. If there is evidence of structural deterioration, corrective action is taken prior to performing the Type A test. The structural deterioration and corrective action are reported in accordance with 10 CFR 50,

Appendix J. Except as described above, during the period between the initiation of the containment inspection and the performance of the Type A test, no repairs or adjustments are made so that the containment can be tested in as close to the "as-is" condition as practical.

Containment isolation valves are placed in their post-accident positions, identified in Table 6.2.3-1, unless such positioning is impractical or unsafe. Test exceptions to post-accident valve positioning are identified in Table 6.2.3-1 or are discussed in the test report. Closure of containment isolation valves is accomplished by normal operation and with no preliminary exercising or adjustments (such as tightening of a valve by manual handwheel after closure by the power actuator). Valve closure malfunctions or valve leakage that requires corrective action before the test is reported in conjunction with the Type A test report.

Those portions of fluid systems that are part of the reactor coolant pressure boundary and are open directly to the containment atmosphere under post-accident conditions and become an extension of the boundary of the containment, are opened or vented to the containment atmosphere prior to and during the test.

Portions of systems inside containment that penetrate containment and could rupture as a result of a loss of coolant accident are vented to the containment atmosphere and drained of water to the extent necessary to provide exposure of the containment isolation valves to containment air test pressure and to allow them to be subjected to the full differential test pressure, except that:

- Systems that are required to maintain the plant in a safe condition during the Type A test remain operable and are not vented.

- Systems that are required to establish and maintain equilibrium containment conditions during Type A testing remain operable and are not vented.

- Systems that are normally filled with water and operating under post-accident conditions are not vented.

Systems not required to be vented and drained for Type A testing are identified in Table 6.2.3-1. The leak rates for the containment isolation valves in these systems, measured by Type C testing, are reported in the Type A test report.

Tanks inside the containment are vented to the containment atmosphere as necessary to protect them from the effects of external test pressure and/or to preclude leakage which could affect the accuracy of the test results. Similarly, instrumentation and other components that could be adversely affected by the test pressure are vented or removed from containment.

The containment atmospheric conditions are allowed to stabilize prior to the start of the Type A test consistent with the guidance of ANSI-56.8. The containment recirculation cooling system and central chilled water system are operated as necessary prior to, and during, the test to maintain stable test conditions.

- Test Method

The Type A test is conducted in accordance with ANSI-56.8, using the absolute method. The test duration is established consistent with ANSI-56.8 following the stabilization period. Periodic measurements of containment pressure, dry bulb temperatures and dew point temperatures (water vapor pressure) are used to determine the decrease in the mass of air in the containment over time. A standard statistical analysis of the data is conducted consistent with recommendations of ANSI-56.8.

The accuracy of the Type A test results is then verified by a supplemental verification test. The supplemental verification test is performed using methodology consistent with the recommendations described in ANSI-56.8.

Test criteria for the Type A test are given in the technical specifications. If any Type A test fails to meet the criteria, the test schedule for subsequent tests is adjusted in accordance with 10 CFR 50, Appendix J as defined in the Containment Leakage Rate Testing Program.

During the period between the completion of one Type A test and the initiation of the containment inspection for the subsequent Type A test, repairs or adjustments are made to components identified as exceeding individual leakage limits, as soon as practical after such leakage is identified.

Containment Penetration Leak Rate Tests (Type B)

The following containment penetrations receive preoperational and periodic Type B leak rate tests in accordance with ANSI-56.8 with test intervals as defined by NEI 94-01 (Reference 30):

- Penetrations whose design incorporates resilient seals, gaskets or sealant compounds
- Air locks and associated door seals
- Equipment and access hatches and associated seals
- Electrical penetrations

Containment penetrations subject to Type B tests are illustrated in Figure 6.2.5-1.

The fuel transfer tube penetration is sealed with a blind flange inside containment. The flanged joint is fitted with testable seals as shown in Figure 3.8.2-4. The two expansion bellows used on the fuel transfer tube penetration are not part of the leakage-limiting boundary of the containment.

The personnel hatches (airlocks) are designed to be tested by internal pressurization. The doors of the personnel hatches have testable seals as shown in Figure 3.8.2-3. Mechanical and electrical penetrations on the personnel hatches are also equipped with testable seals. The hatch cover flanges for the main equipment and maintenance hatches have testable seals as shown in Figure 3.8.2-2. Containment electrical penetrations have testable seals as shown in Figure 3.8.2-6.

Type B leak tests are performed by local pressurization using the test connections shown on Figure 6.2.5-1. Unless otherwise noted in Table 6.2.3-1, the test pressure is not less than the

calculated containment peak accident pressure, P_a. Either the pressure decay or the flowmeter test method is used. These test methods and the test criteria are presented below for Type C tests.

Containment Isolation Valve Leak Rate Tests (Type C)

Containment isolation valves receive preoperational and periodic Type C leak rate tests in accordance with ANSI-56.8 with test intervals as defined by NEI 94-01 (Reference 30). A list of containment isolation valves subject to Type C tests is provided in Table 6.2.3-1. Containment isolation valve arrangement and test connections provided for Type C testing are illustrated on the applicable system piping and instrument diagram figure.

Type C leak tests are performed by local pressurization. Each valve to be tested is closed by normal means without any preliminary exercising or adjustments. Piping is drained and vented as needed and a test volume is established that, when pressurized, will produce a differential pressure across the valve. Table 6.2.3-1 identifies the direction in which the differential pressure is applied.

Isolation valves whose seats may be exposed to the containment atmosphere subsequent to a loss of coolant accident are tested with air or nitrogen at a pressure not less than P_a. Valves in lines which are designed to be, or remain, filled with a liquid for at least 30 days subsequent to a loss of coolant accident are leak rate tested with that liquid at a pressure not less than 1.1 times P_a. Isolation valves tested with liquid are identified in Table 6.2.3-1.

Isolation valves are tested using either the pressure decay or flowmeter method. For the pressure decay method the test volume is pressurized with air or nitrogen. The rate of decay of pressure in the known volume is monitored to calculate the leak rate. For the flowmeter method pressure is maintained in the test volume by supplying air or nitrogen through a calibrated flowmeter. The measured makeup flow rate is the isolation valve leak rate.

The leak rates of penetrations and valves subject to Type B and C testing are combined in accordance with 10 CFR 50, Appendix J. As each Type B or C test, or group of tests, is completed the combined total leak rate is revised to reflect the latest results. Thus, a reliable summary of containment leaktightness is maintained current. Leak rate limits and the criteria for the combined leakage results are described in the technical specifications.

Scheduling and Reporting of Periodic Tests

Schedules for the performance of periodic Type A, B, and C leak rate tests are in accordance with the technical specifications, Chapter 16 as specified in the Containment Leakage Rate Testing Program. Provisions for reporting test results are described in the Containment Leakage Rate Testing Program.

Type B and C tests may be conducted at any time that plant conditions permit, provided that the time between tests for any individual penetration or valve does not exceed the maximum allowable interval specified in the Containment Leakage Rate Testing Program.

Special Testing Requirements

AP1000 does not have a subatmospheric containment or a secondary containment. There are no containment isolation valves which rely on a fluid seal system. Thus, there are no special testing requirements.

6.2.5.2.3 Component Description

The system pressurization equipment is temporarily installed for Type A testing. In addition to one or more compressors, this hardware includes components such as aftercoolers, moisture separators, filters and air dryers. The hardware characteristics may vary from test to test.

The flow control valve in the pressurization line is a leaktight valve capable of throttling to a low flow rate.

6.2.5.2.4 Instrumentation Applications

For Type A testing, instruments are provided to measure containment absolute pressure, dry bulb temperature, dew point temperature, air flow rate, and atmospheric pressure. Data acquisition equipment scans, processes and records data from the individual sensors. For Type B and C testing, instruments are provided to measure pressure, dry bulb temperature, and flow rate.

The quantity and location of Type A instrumentation and permanently installed Type B instrumentation, is indicated on Figure 6.2.5-1. The type, make and range of test instruments may vary from test to test. The instrument accuracy must meet the criteria of Reference 13.

6.2.5.3 Safety Evaluation

The containment leak rate test system has no safety-related function, other than containment isolation and therefore requires no nuclear safety evaluation, other than containment isolation which is described in subsection 6.2.3.

6.2.5.4 Inservice Inspection/Inservice Testing

There are no special inspection or testing requirements for the containment leak rate test system. Test equipment is inspected and instruments are calibrated in accordance with ANSI-56.8 criteria and the requirements of the test procedure.

6.2.6 Combined License Information for Containment Leak Rate Testing

The Combined License applicant is responsible for developing a “Containment Leakage Rate Testing Program” which will identify which Option is to be implemented under 10 CFR 50, Appendix J. Option A defines a prescriptive-based testing approach whereas option B defines a performance-based testing program.

6.2.7 References

1. DELETED

2. "Ice Condenser Containment Pressure Transient Analysis Methods," WCAP-8077, March, 1973 (Proprietary), WCAP-8078 (Non-Proprietary).

3. Shepard, R. M., et al., "Westinghouse Mass and Energy Release Data for Containment Design," WCAP-8264-P-A, June 1975 (Proprietary), and WCAP-8312-A, Revision 2, August 1975 (Non-Proprietary).

4. "Westinghouse LOCA Mass and Energy Release Model for Containment Design - March 1979 Version," WCAP-10325-P-A (Proprietary) and WCAP-10326-A (Non-Proprietary), May 1983.

5. Land, R. E., "Mass and Energy Releases Following a Steam Line Rupture," WCAP-8822 (Proprietary) and WCAP-8860 (Non-Proprietary), September 1976; "Supplement 1 - Calculations of Steam Superheat in Mass/Energy Releases Following a Steamline Rupture," WCAP-8822-P-S1 (Proprietary), January 1985; "Supplement 2 - Impact of Steam Superheat in Mass/Energy Releases Following a Steamline Rupture for Dry and Subatmospheric Containment Designs," WCAP-8822-S2-P-A (Proprietary), September 1986.

6. Burnett, T. W. T., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-Proprietary), April 1984.

7. 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Cooled Nuclear Power Reactors," and Appendix K to 10 CFR 50, "ECCS Evaluation Model."

8. Branch Technical Position CSB6-1, "Minimum Containment Pressure Model for PWR ECCS Performance Evaluation."

9. DELETED

10. DELETED

11. DELETED

12. DELETED

13. ANSI/ANS-56.8-1994, "Containment System Leakage Testing Requirements."

14. 10 CFR 50, Appendix J, "Containment Leak Rate Testing," September 26, 1995.

15. Thomas C. L. Catalytic Processes and Proven Catalysts, Academic Press, 1970.

16. AP600 Standard Safety Analysis Report, Section 6.2.

17. J. Rohde, et al., "Hydrogen Mitigation by Catalytic Recombiners and Ignition During Severe Accidents," Third International Conference on Containment Design and Operation, Canadian Nuclear Society, Toronto, Ontario, October 19-21, 1994.

18. DELETED

19. EPRI Report, "NIS passive autocatalytic recombiner Depletion Rate Equation for Evaluation of Hydrogen Recombination During AP600 Design Basis Accident," EPRI ALWR Program, November 15, 1995.

20. WCAP-15846 (Proprietary) and WCAP-15862 (Non-Proprietary) "WGOTHIC Application to AP600 and AP1000," Revision 1, March 2004.

21. DELETED

22. NUREG-737, "Clarification of TMI Action Plan Requirements," October, 1980

23. NUREG-718. Rev. 2, "Licensing Requirements for Pending Applications for Construction Permits and Manufacturing License," January, 1982.

24. ANSI/ASCE-8-90, Specification for the Design of Cold Formed Stainless Steel Structural Members

25. DELETED

26. WCAP-15965-P (Proprietary) and WCAP-15965-NP (Non-Proprietary), "AP1000 Subcompartment Models," November 2002.

27. DELETED

28. DELETED

29. EPRI Report TR-107517, Volumes 1, 2, and 3, "Generic Model Tests of Passive Autocatalytic Recombiners (PARs) for Combustible Gas Control in Nuclear Power Plants," June 1997.

30. Nuclear Energy Institute Report, NEI 94-01, "Industry Guidelines for Implementing Performance Based Option of 10 CFR 50, Appendix J," Revision 0.

31. Carlin, E. L. and U. Bachrach, "LOFTRAN and LOFTTR2 AP600 Code Applicability Document," WCAP-14234, Revision 1 (Proprietary) and WCAP-14235, Revision 1 (Non-Proprietary), August 1997.

32. WCAP-15644-P (Proprietary) and WCAP-15644-NP (Non-Proprietary), "AP1000 Code Applicability Report," Revision 2, March 2004.

Table 6.2.1.1-1

SUMMARY OF CALCULATED PRESSURES AND TEMPERATURES

Break	Peak Pressure (psig)	Available[1] Margin (psi)	Peak Temperature (°F)
Double-ended hot leg guillotine	50.0	9.0	416.5
Double-ended cold leg guillotine	57.8	1.2	284.9
Full main steamline DER, 30% power, MSIV failure	57.3	1.7	373.9
Full main steamline DER, 101% power, MSIV failure	53.7	5.3	375.3

Note:
1. Design Pressure is 59 psig

Table 6.2.1.1-2

INITIAL CONDITIONS

Internal Temperature (°F)	120
Pressure (psia)	15.7
Relative Humidity (%)	0
Net Free Volume (ft^3)	2.06E+06
External Temperature (°F)	115 dry bulb 80 wet bulb

Table 6.2.1.1-3

RESULTS OF POSTULATED ACCIDENTS

Criterion	Acceptance Criterion Value	Lumped DEHLG LOCA Value	Lumped DECLG LOCA Value	30% Power MSLB Value	External Pressurization Value
GDC 16 & GDC 50 Design Pressure	<59.0 psig	50.0	57.8	57.3	
GDC 38 Rapidly Reduce Containment Pressure	< 29.5 psig		22 at 24 hrs		
GDC 38 & 50 External Pressure	< 2.9 psid				2.4
GDC 38 & GDC 50 Containment Heat Removal Single Failure	Most Severe	Two of Three Trains of PCS Water Supply	Two of Three Trains of PCS Water Supply	Two of Three Trains of PCS Supply	

Tables 6.2.1.1-4 through 6.2.1.1-7 DELETED

Table 6.2.1.1-8

PHYSICAL PROPERTIES OF PASSIVE HEAT SINKS

Material	Density (lbm/ft^3)	Thermal Conductivity (Btu/hr-ft-°F)	Specific Heat (Btu/lbm-°F)	Dry Emis.	Wet Emis.
Epoxy	105	0.1875	0.35	0.81	0.95
Carbon Steel	490.7	23.6	0.107	0.81	0.95
Concrete	140.	0.83	0.19	0.81	0.95
Stainless Steel	501.	9.4	0.12	0.81	0.95
Carbo Zinc	207.5	1.21	0.15	0.81	0.95
Oxidized Carbo Zinc	207.5	0.302	0.15	0.81	0.95
Carbo Zinc-PCS Inside Surface	207.5	0.302	0.15	1e-10	1e-10
Air @ 0°F	0.0864	0.0131	0.240	1e-10	1e-10
Air @ 250°F	0.056	0.0192	0.242	1e-10	1e-10
Air @ 500°F	0.0414	0.0246	0.248	1e-10	1e-10

Table 6.2.1.2-1 (Sheet 1 of 3)

LISTING OF LINES NOT LBB QUALIFIED AND THE CALCULATED MAXIMUM DIFFERENTIAL PRESSURES

AP1000 Room #	Possible(1) Pipe Rupture	Design Differential Pressure (psi)	Maximum Differential(2) Pressure (psi)	Table for M&E Data
11104	None	5.0	NA	NA
11105	None	5.0	NA	NA
11201	4" Pressurizer Spray	5.0	<4.0	6.2.1.3-6
11202	None	5.0	NA	NA
11204	3" Regen HX to SG 3" Purification from CL to Regen HX	5.0	<2.9 <2.9	6.2.1.3-2 6.2.1.3-2
11205	None	5.0	NA	NA
11206	None	5.0	NA	NA
11207	None	5.0	NA	NA
11208	None	5.0	NA	NA
11209 North	None	5.0	NA	NA
11209 Center	3" Purification from Prz Spray 3" Purification to PRHR Return 3" Regen HX to Letdown HX 3" RHR HX 3" Regen HX to RNS pump	5.0	<4.2 <4.2 <4.2 <4.2 <4.2	6.2.1.3-7 6.2.1.3-7 6.2.1.3-7 6.2.1.3-7 6.2.1.3-7
11209 South	3" Regen HX to Letdown HX	5.0	<4.3	6.2.1.3-7
11209 Pipe Tunnel	3" Purification from Prz Spray to Regen HX 3" Purification from Regen HX to PRHR Return 4" SG Blowdown	7.5 7.5	<6.2 <6.2 <6.75	6.2.1.3-7 6.2.1.3-7 6.2.1.3-5

Table 6.2.1.2-1 (Sheet 2 of 3)

LISTING OF LINES NOT LBB QUALIFIED AND THE CALCULATED MAXIMUM DIFFERENTIAL PRESSURES

AP1000 Room #	Possible(1) Pipe Rupture	Design Differential Pressure (psi)	Maximum Differential(2) Pressure (psi)	Table for M&E Data
11300	None	5.0	NA	NA
11301	3" Purification	5.0	<4.0	6.2.1.3-2 6.2.1.3-3
11302	None	5.0	NA	NA
11303	4" Pressurizer Spray	5.0	<3.7	6.2.1.3-6
11304	3" Purification to PRHR return	5.0	<3.6	6.2.1.3-2
	2" CVS Purification to Prz Spray size		<3.6	Bounded by larger break
11305	None	5.0	NA	NA
11400	6" Startup Feedwater	5.0	NA	NA
11401	4" SG Blowdown	5.0	<2.9	6.2.1.3-5
11402	4" SG Blowdown	5.0	<2.9	6.2.1.3-5
11403	3" Letdown	5.0	<4.5	6.2.1.3-3
	2" Aux Spray		<4.5	Bounded by larger break size
	4" Prz Spray at 4 x 2 TEE		<4.5	6.2.1.3-6
	4" Prz Spray at Anchor		<4.5	6.2.1.3-6
11500	None	5.0	NA	NA
11501	None	5.0	NA	NA
11502	None	5.0	NA	NA
11503	4" Pressurizer Spray	5.0	<4.0	6.2.1.3-6
11504	None	5.0	NA	NA
11601	20" Main Feedwater	5.0	NA	NA
	6" Startup Feedwater		NA	NA

Table 6.2.1.2-1 (Sheet 3 of 3)

LISTING OF LINES NOT LBB QUALIFIED AND THE CALCULATED MAXIMUM DIFFERENTIAL PRESSURES

AP1000 Room #	Possible(1) Pipe Rupture	Design Differential Pressure (psi)	Maximum Differential(2) Pressure (psi)	Table for M&E Data
11602	20" Main Feedwater 6" Startup Feedwater	5.0	NA NA	NA NA
11603	4" ADS	5.0	NA	NA
11701	None	5.0	NA	NA
11702	None	5.0	NA	NA
11703	4" ADS	5.0	NA	NA
12306	4" SG Blowdown	6.0	5.85	6.2.1.3-5
12404	1 ft^2 Main Steam Line A	6.0	5.35	6.2.1.3-4
12406	1 ft^2 Main Steam Line B	6.0	5.35	6.2.1.3-4

Notes:
1. "None" indicates that there are no High Energy Lines >1" in diameter that are not qualified to LBB.
2. Structures are designed to a pressurization load of 5.0 psig except as follows; the CVS room pipe tunnel is designed to a pressurization load of 7.5 psig as discussed in DCD subsection 3.8.3.5; the MSIV rooms are designed to a pressurization load of 6 psig as discussed in DCD subsections 3.8.3.5 and 3.8.4.3.1.4.
3. "NA" indicates that no calculation was performed because no rupture was postulated or that the line was postulated to rupture in a region with a large free volume so compartment differential pressures would be negligible.

Table 6.2.1.3-1

SHORT-TERM MASS AND ENERGY INPUTS

	Design Value	Analysis Value
Vessel Outlet Temperature (˚F)	610.0	597.0
Vessel Inlet Temperature (˚F)	535.0	528.6
Initial RCS Pressure (PSIA)	2250.0	2300.0
Zaloudek Coefficient (CK1)		1.018
Zaloudek Coefficient (C1)		0.9

Table 6.2.1.3-2

SHORT-TERM 3-INCH COLD-LEG BREAK MASS AND ENERGY RELEASES

Time (sec)	Mass (lbm/sec)	Energy (Btu/sec)
0.0	0.0	0.0
0.001	3186.8	1.7084E+6
0.05	3186.8	1.7084E+6
1.000	3186.8	1.7084E+6
5.000	3186.8	1.6591E+6
7.000	3186.8	1.6225E+6
10.00	3186.8	1.6005E+6

Table 6.2.1.3-3

SHORT-TERM 3-INCH HOT-LEG BREAK MASS AND ENERGY RELEASES

Time (sec)	Mass (lbm/sec)	Energy (Btu/sec)
0.0	0.0	0.0
0.001	2514.2	1.5623E+6
0.05	2514.2	1.5623E+6
1.000	2514.2	1.5640E+6
5.000	2514.2	1.6947E+6
7.000	2514.2	1.7966E+6
10.00	2514.2	1.8406E+6

Table 6.2.1.3-4

MAIN STEAM LINE BREAK MASS AND ENERGY (1 FT^2 BREAK)

Time (sec)	Mass (lbm/sec)	Energy (Btu/sec)
0	2300	2734200
1.79	2300	2734200
2.79	6990	4304400
3.79	7350	4410700
4.79	7440	4436500
5.79	7440	4436500
6.79	7390	4420700
7.79	7320	4401500
8.79	7200	4366100
9.79	7060	4325700
10.79	6910	4281400
11.79	6730	4225100
12.79	6580	4180900
13.79	6390	4120300
14.79	6220	4066000
15.79	6070	4017700

Table 6.2.1.3-5

4" SG BLOWDOWN LINE MASS AND ENERGY RELEASES

Time (sec)	Total Mass (lbm/sec)	Energy (Btu/sec)
0.0	0.0	0.0
0.492	1451.4	8.106 E+5
0.493	1451.4	8.106 E+5
6.155	1451.4	8.106 E+5
6.156	725.7	4.053 E+5
10.0	725.7	4.053 E+5

Table 6.2.1.3-6

PRESSURIZER SPRAY LINE BREAK RELEASES

Time (sec)	Mass (lbm/sec)	Energy (Btu/sec)
0	3006.872	1794802
0.0503	2957.944	1768521
0.102	2941.763	1759619
0.501	2856.777	1711344
0.763	2854.027	1707538
1	2860.371	1708709
1.075	2860.858	1708365
2	2766.115	1650733
3	2666.345	1590401
4	2564.804	1529641
5	2459.947	1467666

Table 6.2.1.3-7

SHORT TERM 3-INCH SINGLE-ENDED COLD-LEG BREAK MASS AND ENERGY RELEASES

Time (sec)	Mass (lbm/sec)	Energy (Btu/sec)
0.0	0.0	0.0
0.001	1593.4	8.5420E+05
0.050	1593.4	8.5420E+05
1.001	1593.4	8.5420E+05
5.000	1593.4	8.2955E+05
7.000	1593.4	8.1125E+05
10.00	1593.4	8.0025E+05

Table 6.2.1.3-8

BASIS FOR LONG-TERM ANALYSIS

Number of Loops	2
Active Core Length (ft)	14.0
Core Power, license application (MWt)	3400
Nominal Vessel Inlet Temperature (°F)	537.2
Nominal Vessel Outlet Temperature (°F)	610.0
Steam Pressure (psia)	836
Rod Array	17 x 17
Accumulator Temperature (°F)	120.0
Containment Design Pressure (psia)	73.7

Table 6.2.1.3-9 (Sheet 1 of 10)

**LONG-TERM DECL BREAK
MASS AND ENERGY RELEASES**

Time (sec)	Two-Phase Mass (lbm/sec)	Two-Phase Enthalpy (Btu/lbm)	Steam Mass (lbm/sec)	Steam Enthalpy (Btu/lbm)
0.00000	0.00	0.00	0.00	1175.70
0.00107	40101.90	534.00	0.00	1175.70
0.00207	39915.25	534.01	0.00	1175.70
0.10138	61554.15	537.13	0.00	1175.70
0.20136	62844.64	537.19	0.00	1175.70
0.30113	63197.94	537.31	0.00	1175.70
0.40114	90102.34	537.54	0.00	1175.70
0.50114	87175.55	537.84	0.00	1175.70
0.60104	77832.03	538.10	0.00	1175.70
0.70156	76035.73	539.23	0.00	1175.70
0.80126	75057.70	540.40	0.00	1175.70
0.90109	74054.78	541.60	0.00	1175.70
1.00110	72617.18	542.99	0.00	1175.70
1.10121	71749.56	544.67	0.00	1175.70
1.20123	70850.35	546.53	0.00	1175.70
1.30132	70080.46	548.55	0.00	1175.70
1.40101	69403.67	550.64	0.00	1175.70
1.50119	67364.55	552.58	0.00	1175.70
1.60132	64086.75	554.29	0.00	1175.70
1.70103	61072.95	555.70	0.00	1175.70
1.80131	59450.18	556.71	0.00	1175.70
1.90130	58452.93	557.52	0.00	1175.70
2.00120	57281.27	558.12	0.00	1175.70

Table 6.2.1.3-9 (Sheet 2 of 10)

LONG-TERM DECL BREAK MASS AND ENERGY RELEASES

Time (sec)	Two-Phase Mass (lbm/sec)	Two-Phase Enthalpy (Btu/lbm)	Steam Mass (lbm/sec)	Steam Enthalpy (Btu/lbm)
2.10115	55584.88	558.66	0.00	1175.70
2.20125	53824.43	559.17	0.00	1175.70
2.30135	52171.66	559.56	0.00	1175.70
2.40129	50225.01	559.91	0.00	1175.70
2.50102	49035.85	560.24	0.00	1175.70
2.60101	46447.50	560.29	0.00	1175.70
2.70116	44544.15	559.85	0.00	1175.70
2.80106	44562.50	559.57	0.00	1175.70
2.90172	44056.27	559.45	0.00	1175.70
3.00116	43801.26	559.46	0.00	1175.70
3.10105	41644.56	559.79	0.00	1175.70
3.20124	41456.14	559.96	0.00	1175.70
3.30132	40385.31	560.20	0.00	1175.70
3.40119	36808.00	560.70	0.00	1175.70
3.50168	24697.17	561.73	0.00	1175.70
3.60172	22506.86	562.51	0.00	1175.70
3.70154	25781.65	560.58	0.00	1175.70
3.80166	26269.38	559.73	0.00	1175.70
3.90249	26335.91	558.96	0.00	1175.70
4.00148	26059.32	558.57	0.00	1175.70
4.20067	24781.47	558.85	0.00	1175.70
4.40012	23650.96	559.05	0.00	1175.70
4.60047	23477.64	557.48	0.00	1175.70

Table 6.2.1.3-9 (Sheet 3 of 10)

LONG-TERM DECL BREAK MASS AND ENERGY RELEASES

Time (sec)	Two-Phase Mass (lbm/sec)	Two-Phase Enthalpy (Btu/lbm)	Steam Mass (lbm/sec)	Steam Enthalpy (Btu/lbm)
4.80046	23551.74	556.17	0.00	1175.70
5.00056	23114.84	555.40	0.00	1175.70
5.20013	22453.61	555.60	0.00	1175.70
5.40134	21887.77	556.33	0.00	1175.70
5.60063	21783.63	556.58	0.00	1175.70
5.80078	21947.20	556.37	0.00	1175.70
6.00026	21772.36	556.56	0.00	1175.70
6.20002	21429.88	556.74	0.00	1175.70
6.40050	21396.43	556.71	0.00	1175.70
6.60013	21470.52	556.87	0.00	1175.70
6.80007	21228.64	556.84	0.00	1175.70
7.00005	21018.36	556.92	0.00	1175.70
7.20001	20798.12	557.24	0.00	1175.70
7.40077	20611.53	557.63	0.00	1175.70
7.60075	20505.96	557.83	0.00	1175.70
7.80079	20414.06	557.92	0.00	1175.70
8.00219	20288.48	558.07	0.00	1175.70
8.20047	20108.89	558.42	0.00	1175.70
8.40002	20094.72	558.98	0.00	1175.70
8.60055	20137.87	559.85	0.00	1175.70
8.80053	20149.05	561.16	0.00	1175.70
9.00009	20167.54	562.81	0.00	1175.70
9.20042	20171.29	564.74	0.00	1175.70

Table 6.2.1.3-9 (Sheet 4 of 10)

LONG-TERM DECL BREAK
MASS AND ENERGY RELEASES

Time (sec)	Two-Phase Mass (lbm/sec)	Two-Phase Enthalpy (Btu/lbm)	Steam Mass (lbm/sec)	Steam Enthalpy (Btu/lbm)
9.40115	20102.81	566.48	0.00	1175.70
9.60167	19918.92	568.19	0.00	1175.70
9.80066	19707.21	569.96	0.00	1175.70
10.0001	19564.71	571.61	0.00	1175.70
10.2012	19260.91	573.76	0.00	1175.70
10.2031	19257.99	573.78	0.00	1175.70
10.4011	19108.20	576.24	0.00	1175.70
10.6004	19023.21	578.36	0.00	1175.70
10.8006	18739.47	580.56	0.00	1175.70
11.0005	18463.53	582.66	0.00	1175.70
11.2007	18556.93	586.68	0.00	1175.70
11.4001	18437.49	590.46	0.00	1175.70
11.6008	17957.61	593.86	0.00	1175.70
11.8004	17531.58	598.12	0.00	1175.70
12.0000	17112.43	603.36	0.00	1175.70
12.2009	16669.07	609.51	0.00	1175.70
12.4001	16247.57	616.42	0.00	1175.70
12.6006	15801.61	624.39	0.00	1175.70
12.8009	15355.21	633.62	0.00	1175.70
13.0007	14910.90	644.37	0.00	1175.70
13.2004	14500.49	656.96	0.00	1175.70
13.4009	13747.09	673.27	0.00	1175.70
13.6002	12860.19	693.22	0.00	1175.70

Table 6.2.1.3-9 (Sheet 5 of 10)

LONG-TERM DECL BREAK
MASS AND ENERGY RELEASES

	Two-Phase		Steam	
Time (sec)	**Mass (lbm/sec)**	**Enthalpy (Btu/lbm)**	**Mass (lbm/sec)**	**Enthalpy (Btu/lbm)**
13.8004	11958.24	715.43	0.00	1175.70
14.0002	11113.02	739.25	0.00	1175.70
14.2006	10366.37	764.19	0.00	1175.70
14.4003	9732.35	788.88	0.00	1175.70
14.6005	9216.37	810.72	0.00	1175.70
14.8002	8813.81	827.63	0.00	1175.70
15.0002	8502.28	839.91	0.00	1175.70
15.2007	8301.00	843.93	0.00	1175.70
15.4003	8213.22	839.45	0.00	1175.70
15.6004	8154.61	833.07	0.00	1175.70
15.8003	7986.29	835.70	0.00	1175.70
16.0001	7716.79	848.14	0.00	1175.70
16.2002	7372.16	869.28	0.00	1175.70
16.4002	6978.55	892.74	0.00	1175.70
16.6003	6652.71	907.89	0.00	1175.70
16.8005	6360.59	913.06	0.00	1175.70
17.0005	6062.02	909.08	0.00	1175.70
17.2005	5744.75	902.68	0.00	1175.70
17.4005	5587.27	889.97	0.00	1175.70
17.6006	5499.50	873.25	0.00	1175.70
17.8005	5360.12	849.96	0.00	1175.70
18.0003	5220.68	823.25	0.00	1175.70
18.2007	5093.38	793.98	0.00	1175.70
18.4003	5007.32	759.78	0.00	1175.70

Table 6.2.1.3-9 (Sheet 6 of 10)

LONG-TERM DECL BREAK
MASS AND ENERGY RELEASES

Time (sec)	Two-Phase Mass (lbm/sec)	Two-Phase Enthalpy (Btu/lbm)	Steam Mass (lbm/sec)	Steam Enthalpy (Btu/lbm)
18.6004	4929.92	726.78	0.00	1175.70
18.8003	4803.52	703.73	0.00	1175.70
19.0002	4585.16	694.88	0.00	1175.70
19.2008	4333.16	693.77	0.00	1175.70
19.4006	4091.15	693.89	0.00	1175.70
19.6002	3878.86	690.54	0.00	1175.70
19.8002	3706.76	679.88	0.00	1175.70
20.0008	3581.66	660.10	0.00	1175.70
20.2008	3553.34	631.10	0.00	1175.70
20.4007	3599.42	602.07	0.00	1175.70
20.6009	3595.10	582.37	0.00	1175.70
20.8006	3598.93	566.07	0.00	1175.70
21.0006	3565.59	552.01	0.00	1175.70
21.2004	3508.49	539.93	0.00	1175.70
21.4004	3460.68	527.33	0.00	1175.70
21.6002	3416.69	513.70	0.00	1175.70
21.8005	3338.61	502.04	0.00	1175.70
22.0003	3302.42	487.26	0.00	1175.70
22.2003	3207.42	473.85	0.00	1175.70
22.4007	3111.19	460.35	0.00	1175.70
22.6002	3025.32	448.58	0.00	1175.70
22.8003	2933.59	437.40	0.00	1175.70
23.0006	2757.37	428.95	0.00	1175.70
23.2001	2594.96	423.71	0.00	1175.70

Table 6.2.1.3-9 (Sheet 7 of 10)

LONG-TERM DECL BREAK
MASS AND ENERGY RELEASES

	Two-Phase		Steam	
Time (sec)	**Mass (lbm/sec)**	**Enthalpy (Btu/lbm)**	**Mass (lbm/sec)**	**Enthalpy (Btu/lbm)**
23.4005	2396.47	419.54	0.00	1175.70
23.6004	2108.35	379.61	0.00	1175.70
23.8003	1857.94	373.33	0.00	1175.70
24.0002	1612.87	362.07	0.00	1175.70
24.2004	1301.63	354.85	0.00	1175.70
24.4007	823.13	356.86	0.00	1175.70
24.6003	246.54	343.53	0.00	1175.70
27.9804	925.63	150.23	316.54	1175.70
35.2825	826.09	157.90	311.47	1175.70
39.9899	775.94	162.76	308.18	1175.70
44.2617	723.03	168.01	306.93	1175.70
51.1127	704.00	172.81	304.17	1175.70
55.3304	701.22	175.08	302.31	1175.70
60.0868	697.63	177.54	300.16	1175.70
64.6161	693.19	179.84	298.72	1175.70
69.7598	687.77	182.32	297.04	1175.70
75.6479	681.00	185.00	295.06	1175.70
79.6980	679.60	186.42	293.59	1175.70
86.4256	665.97	189.60	292.06	1175.70
91.0004	656.75	191.64	290.98	1175.70
95.0004	648.93	193.32	290.00	1175.70
101.000	636.48	195.81	288.52	1175.70
105.000	627.50	197.48	287.81	1175.70
111.000	613.53	199.94	286.71	1175.70

Table 6.2.1.3-9 (Sheet 8 of 10)

LONG-TERM DECL BREAK
MASS AND ENERGY RELEASES

	Two-Phase		Steam	
Time (sec)	**Mass (lbm/sec)**	**Enthalpy (Btu/lbm)**	**Mass (lbm/sec)**	**Enthalpy (Btu/lbm)**
119.000	594.18	203.19	285.24	1175.70
132.233	559.95	208.66	282.79	1175.70
142.632	532.83	212.93	280.84	1175.70
153.031	506.45	217.12	278.86	1175.70
163.430	479.90	221.40	277.65	1175.70
168.629	466.85	223.55	277.04	1175.70
184.228	465.18	222.93	273.60	1175.70
194.627	460.95	222.92	271.40	1175.70
215.040	0.00	1175.70	160.54	1175.70
225.145	0.00	1175.70	249.96	1175.70
251.346	14.25	911.14	314.64	1175.70
262.107	9.67	1175.70	319.78	1175.70
278.625	20.13	745.83	313.65	1175.70
299.449	17.05	817.48	309.40	1175.70
319.815	19.05	758.63	304.24	1175.70
341.558	21.94	693.26	298.67	1175.70
357.381	24.26	651.67	294.63	1175.70
380.089	26.62	614.66	289.13	1175.70
401.340	28.71	586.06	284.10	1175.70
422.890	109.56	340.62	200.31	1175.70
439.297	110.22	337.36	197.42	1175.70
461.722	110.99	333.06	193.56	1175.70
482.520	111.61	329.17	190.07	1175.70
503.318	112.17	325.39	186.66	1175.70

Table 6.2.1.3-9 (Sheet 9 of 10)

LONG-TERM DECL BREAK
MASS AND ENERGY RELEASES

	Two-Phase		Steam	
Time (sec)	**Mass (lbm/sec)**	**Enthalpy (Btu/lbm)**	**Mass (lbm/sec)**	**Enthalpy (Btu/lbm)**
518.916	112.53	322.62	184.16	1175.70
539.714	112.95	319.00	180.89	1175.70
560.512	113.30	315.47	177.70	1175.70
581.309	113.56	312.06	174.58	1175.70
602.107	113.75	308.73	171.53	1175.70
648.902	113.47	301.90	165.40	1175.70
701.677	112.86	294.60	158.84	1175.70
749.388	111.86	288.54	153.24	1175.70
801.382	110.50	282.33	147.46	1175.70
848.619	108.81	277.21	142.71	1175.70
898.374	106.72	272.23	137.97	1175.70
947.831	104.35	267.72	133.50	1175.70
1002.89	101.61	262.97	128.76	1175.70
1129.21	520.75	138.31	109.82	1175.70
1279.90	526.15	130.80	101.47	1175.70
1380.02	527.33	126.61	96.50	1175.70
1531.16	528.13	121.16	89.72	1175.70
1984.63	525.60	109.54	74.23	1175.70
3997.77	472.81	94.62	46.84	1175.70
6009.01	414.30	93.29	38.46	1175.70
6512.70	387.21	93.48	37.39	1175.70
7518.20	347.96	93.79	35.49	1175.70
8022.81	325.75	94.04	34.62	1175.70
9980.83	252.40	95.30	32.29	1175.70

Table 6.2.1.3-9 (Sheet 10 of 10)

**LONG-TERM DECL BREAK
MASS AND ENERGY RELEASES**

	Two-Phase		Steam	
Time (sec)	**Mass (lbm/sec)**	**Enthalpy (Btu/lbm)**	**Mass (lbm/sec)**	**Enthalpy (Btu/lbm)**
10000.0	0.00	1171.70	37.37	1171.70
15005.0	0.00	1171.70	33.41	1171.70
20005.8	0.00	1171.70	30.93	1171.70
26007.3	0.00	1171.70	29.44	1171.70
30007.9	0.00	1171.70	28.45	1171.70
36008.1	0.00	1171.70	26.82	1171.70
40000.0	0.00	1171.70	25.73	1171.70
60000.0	0.00	1171.70	23.02	1171.70
80000.0	0.00	1171.70	21.25	1171.70
100000.0	0.00	1171.70	19.92	1171.70
150000.0	0.00	1171.70	17.61	1171.70
200000.0	0.00	1171.70	16.03	1171.70
400000.0	0.00	1171.70	12.47	1171.70
600000.0	0.00	1171.70	10.59	1171.70
800000.0	0.00	1171.70	9.37	1171.70
1000000.0	0.00	1171.70	8.53	1171.70
1500000.0	0.00	1171.70	7.17	1171.70
2000000.0	0.00	1171.70	6.31	1171.70
4000000.0	0.00	1171.70	4.48	1171.70

Table 6.2.1.3-10 (Sheet 1 of 5)

BLOWDOWN DEHL BREAK
MASS AND ENERGY RELEASES

Time (sec)	Two-Phase Mass Flow (lbm/sec)	Two-Phase Average Enthalpy (Btu/lbm)	Steam Mass Flow (lbm/sec)	Steam Enthalpy (Btu/lbm)
0	0.00	0.00	0.00	1175.70
0.00102	99770.57	634.47	0.00	1175.70
0.00203	103654.13	634.42	0.00	1175.70
0.00325	102317.94	634.36	0.00	1175.70
0.10143	72808.51	643.92	0.00	1175.70
0.201	69112.58	643.43	0.00	1175.70
0.3017	65624.45	642.91	0.00	1175.70
0.40149	62758.92	641.86	0.00	1175.70
0.50153	61567.32	639.73	0.00	1175.70
0.60101	60833.37	637.81	0.00	1175.70
0.70153	59977.58	636.73	0.00	1175.70
0.8012	59096.96	636.40	0.00	1175.70
0.90111	58329.97	637.38	0.00	1175.70
1.00115	57441.53	639.25	0.00	1175.70
1.10182	56297.40	641.12	0.00	1175.70
1.20137	55219.48	643.26	0.00	1175.70
1.30107	54306.80	645.86	0.00	1175.70
1.40126	53505.66	648.46	0.00	1175.70
1.50117	52669.21	650.02	0.00	1175.70
1.60124	51630.77	649.52	0.00	1175.70
1.70144	50411.95	647.57	0.00	1175.70
1.80124	49109.69	646.15	0.00	1175.70
1.90154	47942.33	647.86	0.00	1175.70
2.00157	46924.47	648.55	0.00	1175.70
2.10154	46046.07	648.81	0.00	1175.70

Table 6.2.1.3-10 (Sheet 2 of 5)

BLOWDOWN DEHL BREAK
MASS AND ENERGY RELEASES

	Two-Phase		Steam	
Time (sec)	**Mass Flow (lbm/sec)**	**Average Enthalpy (Btu/lbm)**	**Mass Flow (lbm/sec)**	**Enthalpy (Btu/lbm)**
2.20166	45225.16	648.31	0.00	1175.70
2.30122	44426.64	647.30	0.00	1175.70
2.40106	43704.80	646.42	0.00	1175.70
2.50112	43064.76	645.58	0.00	1175.70
2.60164	42490.84	644.69	0.00	1175.70
2.70139	41970.18	643.82	0.00	1175.70
2.80131	41490.98	643.06	0.00	1175.70
2.90131	41025.03	642.40	0.00	1175.70
3.00122	40569.69	641.99	0.00	1175.70
3.1011	40139.29	641.76	0.00	1175.70
3.20126	39729.88	641.53	0.00	1175.70
3.30114	39346.44	641.17	0.00	1175.70
3.40184	39015.77	640.95	0.00	1175.70
3.50225	38676.04	639.59	0.00	1175.70
3.60184	38461.47	636.58	0.00	1175.70
3.7011	38352.34	633.74	0.00	1175.70
3.80166	38283.64	630.94	0.00	1175.70
3.9019	38248.93	628.22	0.00	1175.70
4.00108	38210.52	625.78	0.00	1175.70
4.20203	38187.52	622.32	0.00	1175.70
4.40022	38294.31	616.00	0.00	1175.70
4.601	38689.69	609.29	0.00	1175.70
4.80188	39168.32	602.87	0.00	1175.70
5.00024	39618.20	595.92	0.00	1175.70
5.20004	32891.82	633.76	0.00	1175.70

Table 6.2.1.3-10 (Sheet 3 of 5)

BLOWDOWN DEHL BREAK
MASS AND ENERGY RELEASES

	Two-Phase		Steam	
Time (sec)	**Mass Flow (lbm/sec)**	**Average Enthalpy (Btu/lbm)**	**Mass Flow (lbm/sec)**	**Enthalpy (Btu/lbm)**
5.40053	33062.25	629.65	0.00	1175.70
5.60057	33112.56	625.13	0.00	1175.70
5.80033	33082.38	621.24	0.00	1175.70
6.00036	33028.59	617.76	0.00	1175.70
6.20059	32943.66	614.28	0.00	1175.70
6.40393	32600.94	613.74	0.00	1175.70
6.60089	32066.08	614.83	0.00	1175.70
6.8009	31512.96	615.44	0.00	1175.70
7.00181	31102.62	614.04	0.00	1175.70
7.20191	30755.48	611.90	0.00	1175.70
7.40158	30407.63	609.95	0.00	1175.70
7.60198	30019.89	608.56	0.00	1175.70
7.80185	29566.94	607.83	0.00	1175.70
8.00165	29037.50	607.68	0.00	1175.70
8.20044	28397.71	608.14	0.00	1175.70
8.40205	27586.70	609.38	0.00	1175.70
8.60188	26586.93	611.63	0.00	1175.70
8.80013	25517.09	614.69	0.00	1175.70
9.00216	24520.32	618.22	0.00	1175.70
9.20113	23609.85	625.16	0.00	1175.70
9.40129	22871.46	624.66	0.00	1175.70
9.6002	22143.20	630.71	0.00	1175.70
9.80185	21147.92	635.15	0.00	1175.70
10.00099	20493.19	639.01	0.00	1175.70
10.20098	19537.08	651.50	0.00	1175.70

Table 6.2.1.3-10 (Sheet 4 of 5)

BLOWDOWN DEHL BREAK
MASS AND ENERGY RELEASES

Time (sec)	Two-Phase Mass Flow (lbm/sec)	Two-Phase Average Enthalpy (Btu/lbm)	Steam Mass Flow (lbm/sec)	Steam Enthalpy (Btu/lbm)
10.40037	18805.30	652.94	0.00	1175.70
10.60119	17894.46	667.75	0.00	1175.70
10.80209	17080.30	671.94	0.00	1175.70
11.0015	16261.35	688.85	0.00	1175.70
11.20034	15271.59	701.62	0.00	1175.70
11.40022	14660.86	714.12	0.00	1175.70
11.60041	13617.39	740.12	0.00	1175.70
11.80141	12895.14	748.33	0.00	1175.70
12.00023	12038.64	782.33	0.00	1175.70
12.20011	11065.42	817.71	0.00	1175.70
12.40148	10418.49	829.98	0.00	1175.70
12.60047	9562.52	883.55	0.00	1175.70
12.80136	8581.15	938.74	0.00	1175.70
13.00117	7816.32	961.86	0.00	1175.70
13.20024	7597.57	925.35	0.00	1175.70
13.40038	7022.58	964.86	0.00	1175.70
13.6008	6577.45	989.61	0.00	1175.70
13.80013	6289.86	977.56	0.00	1175.70
14.00032	6212.87	979.55	0.00	1175.70
14.20022	5647.20	1025.25	0.00	1175.70
14.40091	5242.09	1046.18	0.00	1175.70
14.60061	5219.16	989.08	0.00	1175.70
14.80064	4846.19	1036.96	0.00	1175.70
15.00065	4391.91	1081.57	0.00	1175.70
15.20072	4058.23	1103.80	0.00	1175.70

Table 6.2.1.3-10 (Sheet 5 of 5)

BLOWDOWN DEHL BREAK
MASS AND ENERGY RELEASES

Time (sec)	Two-Phase Mass Flow (lbm/sec)	Two-Phase Average Enthalpy (Btu/lbm)	Steam Mass Flow (lbm/sec)	Steam Enthalpy (Btu/lbm)
15.40007	3788.20	1120.16	0.00	1175.70
15.60035	3741.64	1055.07	0.00	1175.70
15.80017	3366.84	1145.52	0.00	1175.70
16.00082	2948.77	1207.77	0.00	1175.70
16.20004	2701.98	1225.71	0.00	1175.70
16.40059	2498.77	1231.52	0.00	1175.70
16.601	2312.92	1236.51	0.00	1175.70
16.80041	2148.29	1239.76	0.00	1175.70
17.00038	1967.93	1242.91	0.00	1175.70
17.20015	1783.43	1245.55	0.00	1175.70
17.4001	1611.14	1247.67	0.00	1175.70
17.60085	1450.09	1249.97	0.00	1175.70
17.80097	1301.35	1252.51	0.00	1175.70
18.00058	1161.90	1257.81	0.00	1175.70
18.20104	1019.85	1260.35	0.00	1175.70
18.40079	882.43	1262.91	0.00	1175.70
18.60083	753.82	1265.78	0.00	1175.70
18.80084	630.55	1269.18	0.00	1175.70
19.00031	492.72	1273.10	0.00	1175.70
19.20082	344.56	1278.20	0.00	1175.70
19.40054	220.70	1287.81	0.00	1175.70
19.60021	0.00	0.00	0.00	1175.70
20.18205	0.00	0.00	0.00	1175.70

Table 6.2.1.4-1 not used.

Table 6.2.1.4-2 (Sheet 1 of 5)

MASS AND ENTHALPY RELEASE DATA FOR THE CASE OF MAIN STEAM LINE FULL DOUBLE ENDED RUPTURE FROM 30% POWER LEVEL WITH FAULTED LOOP MAIN STEAM LINE ISOLATION VALVE FAILURE THAT PRODUCES HIGHEST CONTAINMENT PRESSURE

Initial steam generator mass (lbm)	: 164530
Mass added by feedwater flashing (lbm)	: 10390
Mass added from initial steamline header blowdown (lbm)	: 9970
Initial steam pressure (psia)	: 976.5
Feedwater line isolation at (sec)	: 7.92
Steam line isolation at (sec)	: 7.92

Time (sec)	Mass (lbm/sec)	Enthalpy (Btu/lbm)
0.0	0	1189
0.1	17840	1189
0.2	17392	1190
0.4	16795	1190
0.7	16001	1191
0.9	15517	1191
1.3	14637	1192
1.4	5327	1192
1.5	5327	1192
3.3	5072	1194
4.4	4932	1196
5.5	4807	1197
7.5	4604	1198
8.7	4521	1199
8.8	2286	1199
11.0	2185	1200
15.3	1980	1202
17.5	1882	1202
19.7	1789	1203
21.9	1703	1203
24.0	1627	1204

Table 6.2.1.4-2 (Sheet 2 of 5)

MASS AND ENTHALPY RELEASE DATA FOR THE CASE OF MAIN STEAM LINE FULL DOUBLE ENDED RUPTURE FROM 30% POWER LEVEL WITH FAULTED LOOP MAIN STEAM LINE ISOLATION VALVE FAILURE THAT PRODUCES HIGHEST CONTAINMENT PRESSURE

Time (sec)	Mass (lbm/sec)	Enthalpy (Btu/lbm)
26.2	1551	1204
28.4	1481	1204
30.5	1419	1204
32.7	1358	1204
36.1	1273	1204
38.7	1214	1204
41.3	1161	1204
43.9	1111	1204
46.5	1065	1204
49.1	1023	1204
51.7	984	1204
54.4	946	1204
57.0	912	1203
59.6	881	1203
62.2	852	1203
64.8	825	1203
67.5	800	1202
72.7	755	1202
78.0	716	1201
83.2	682	1201
88.5	651	1200
93.7	625	1200
99.0	601	1199
104.2	580	1199
109.5	560	1198
114.7	542	1198

Table 6.2.1.4-2 (Sheet 3 of 5)

MASS AND ENTHALPY RELEASE DATA FOR THE CASE OF MAIN STEAM LINE FULL DOUBLE ENDED RUPTURE FROM 30% POWER LEVEL WITH FAULTED LOOP MAIN STEAM LINE ISOLATION VALVE FAILURE THAT PRODUCES HIGHEST CONTAINMENT PRESSURE

Time (sec)	Mass (lbm/sec)	Enthalpy (Btu/lbm)
120.0	526	1197
125.2	510	1197
135.7	483	1196
141.0	471	1195
151.5	448	1195
162.0	429	1194
172.5	412	1193
183.0	397	1193
193.5	384	1192
204.0	373	1191
214.4	363	1191
224.9	354	1191
235.4	346	1190
245.9	339	1190
266.9	326	1189
287.9	315	1188
308.9	305	1188
329.9	297	1187
350.9	289	1187
371.9	282	1186
413.9	270	1186
455.8	259	1185
497.7	249	1184
581.7	230	1183
623.7	220	1182
665.7	210	1181

Table 6.2.1.4-2 (Sheet 4 of 5)

MASS AND ENTHALPY RELEASE DATA FOR THE CASE OF MAIN STEAM LINE FULL DOUBLE ENDED RUPTURE FROM 30% POWER LEVEL WITH FAULTED LOOP MAIN STEAM LINE ISOLATION VALVE FAILURE THAT PRODUCES HIGHEST CONTAINMENT PRESSURE

Time (sec)	Mass (lbm/sec)	Enthalpy (Btu/lbm)
707.6	201	1180
740.5	189	1183
757.0	183	1185
765.2	179	1186
773.4	175	1188
781.6	170	1190
785.7	167	1191
789.8	163	1192
793.9	159	1194
798.0	154	1195
802.1	148	1197
806.2	142	1199
811.7	132	1201
814.5	128	1203
816.5	124	1204
818.6	119	1205
820.7	114	1207
822.7	109	1208
826.8	97	1211
833.0	79	1215
833.3	78	1215
833.4	78	1215
833.5	76	1215
833.7	75	1216
834.0	72	1216
835.0	65	1217

Table 6.2.1.4-2 (Sheet 5 of 5)

MASS AND ENTHALPY RELEASE DATA FOR THE CASE OF MAIN STEAM LINE FULL DOUBLE ENDED RUPTURE FROM 30% POWER LEVEL WITH FAULTED LOOP MAIN STEAM LINE ISOLATION VALVE FAILURE THAT PRODUCES HIGHEST CONTAINMENT PRESSURE

Time (sec)	Mass (lbm/sec)	Enthalpy (Btu/lbm)
835.5	61	1217
836.0	57	1218
836.5	53	1218
837.0	48	1218
837.2	46	1218
837.6	42	1219
837.7	42	1219
837.8	40	1219
837.9	40	1219
838.0	37	1219
838.1	38	1219
838.2	35	1219
838.3	36	1219
838.4	32	1219
838.5	33	1219
838.6	29	1219
838.7	30	1219
838.8	26	1219
838.9	25	1219
839.0	23	1219
839.1	20	1220
839.2	0	1150
1000.0	0	1150

Table 6.2.1.4-3 not used.

Table 6.2.1.4-4

PLANT DATA USED FOR MASS AND ENERGY RELEASES DETERMINATION

Plant data for all cases:	
Power, Nominal Rating (MWt)	3415
Nominal RCS Flow (GPM)	299,880
Nominal Full Load T_{avg} (°F)	573.6
Nominal RCS Pressure (psia)	2250
Nominal Steam Temperature (°F)	525.0
Nominal Feedwater Enthalpy (BTU/lbm)	419.3

Table 6.2.1.5-1 (Sheet 1 of 3)

MINIMUM CONTAINMENT PRESSURE MASS AND ENERGY RELEASES

Time (sec)	Mass Release (lbm/s)	Energy Release (BTU/s)
0.00	8048.80	4167084
0.50	57353.59	29590134
1.00	55005.49	28459890
1.50	52270.23	27143131
2.00	45818.80	23911847
2.50	40552.88	21238707
3.00	35593.76	18686030
3.50	31914.45	16783283
4.00	29784.90	15589765
4.50	28709.72	14998047
5.00	27586.29	14406259
5.50	25600.61	13417019
6.00	23864.42	12587926
6.50	22163.83	11750443
7.00	20713.23	11001374
7.50	19408.78	10369133
8.00	18043.54	9723079
8.50	16763.18	9137172
9.00	15845.12	8692219
9.50	15083.13	8272394
10.00	15095.14	8068458
10.50	14612.10	7748769
11.00	14451.26	7596588
11.50	14577.73	7558015
12.00	13902.09	7199530
12.50	13233.19	6871044
13.00	12329.50	6425770

Table 6.2.1.5-1 (Sheet 2 of 3) MINIMUM CONTAINMENT PRESSURE MASS AND ENERGY RELEASES		
Time (sec)	**Mass Release (lbm/s)**	**Energy Release (BTU/s)**
13.50	11496.19	6015711
14.00	10810.17	5675010
14.50	10242.59	5395077
15.00	9748.16	5140974
15.50	9413.90	4932896
16.00	9217.57	4774288
16.50	9160.19	4671156
17.00	8988.02	4541615
17.50	8647.66	4367756
18.00	8095.50	4141443
18.50	7792.72	3991404
19.00	7287.82	3785419
19.50	6383.36	3493081
20.00	5976.54	3304023
20.50	5697.54	3160302
21.00	5179.90	2960478
21.50	4823.76	2783870
22.00	4714.63	2647153
22.50	4528.89	2458032
23.00	4239.94	2305475
23.50	3549.63	2080235
24.00	3564.29	2037115
24.50	3556.37	1902678
25.00	3457.20	1779022
25.50	3283.33	1644613
26.00	3005.74	1567032
26.50	2766.47	1439366
27.00	2913.81	1359147

Table 6.2.1.5-1 (Sheet 3 of 3)

MINIMUM CONTAINMENT PRESSURE MASS AND ENERGY RELEASES

Time (sec)	Mass Release (lbm/s)	Energy Release (BTU/s)
27.50	2596.37	1241769
28.00	2735.01	1223341
28.50	2801.99	1216721
29.00	2514.82	1066887
29.50	2166.51	1002084
30.00	2357.82	967204
30.50	2270.68	831612
31.00	2053.97	802888
31.50	2072.48	750472
32.00	2027.79	699692
32.50	1971.58	675788
33.00	1873.58	674471
33.50	1756.97	686106
34.00	1789.48	677109
34.50	1582.86	611478
35.00	1510.34	573832
35.50	1559.28	565846
36.00	1378.92	514559
36.50	1220.64	457942
37.00	1124.18	360695
37.50	1108.51	350376
38.00	996.97	364514
38.50	832.57	326368
39.00	741.62	296555
39.50	631.04	266795
40.00	527.58	237904

Table 6.2.2-1

PASSIVE CONTAINMENT COOLING SYSTEM PERFORMANCE PARAMETERS

PCCWST useable capacity for PCS (gal) - Minimum	756,700
PCCWST useable capacity for FPS(2) (gal) - Minimum	18,000
Flow duration from PCCWST (days) - Minimum	3
PCCWST minimum temperature (°F)	40
PCCWST maximum temperature (°F)	120
Upper annulus drain rate (per drain) - Minimum	525 gpm
PCCAWST(4) long-term makeup rate to containment - Minimum	100 gpm
PCCAWST long-term makeup to spent fuel pool – Minimum	35 gpm
PCCAWST long-term makeup duration - Minimum	4 days
PCCWST long-term makeup to spent fuel pool – Minimum	118 gpm

PCCWST Water Elevation (Note 3) (feet)	Nominal Design Flow (gpm)	Minimum Design Flow (gpm)	Safety Analysis Flow (gpm)	Wetted Coverage (Note 3) (% of circumference)
27.5	494.6 (Note 5)	471.1	469.1	90
24.1	247.1	238.4	226.6	90
20.3	190.8	184.0	176.3	72.9
16.8	157.1	151.4	144.2	59.6
4.0 (Note 6)	113.1	109.6		
			100.7 @ 72 hours	41.6

Notes:
1. PCCWST = passive containment cooling water storage tank
2. FPS = fire protection system
3. PCCWST Water Elevation corresponds to the nominal standpipe elevations in feet above the tank floor (Reference Plant Elevation 298′-9″, see Figure 3.8.4-2). Wetted coverage is measured as the linear percentage of the containment shell circumference wetted measured at the upper spring line for the safety analysis flow rate conditions.
4. PCCAWST = passive containment cooling ancillary water storage tank
5. The initial nominal design flow is based on the nominal PCCWST water elevation.
6. This elevation is the calculated water level at 72 hours after initiation of PCS flow, based on the minimum design flow rates.

Table 6.2.2-2

COMPONENT DATA
PASSIVE CONTAINMENT COOLING SYSTEM
(NOMINAL)

Passive Containment Cooling Water Storage Tank	
Volume (gal) - Minimum	756,700
Design temperature (°F)	125
Design pressure (psig)	Atmospheric
Material	Concrete with stainless steel liner
Standpipe Elevations Above Bottom of Tank Floor (Plant Elevation 298′-9″)	
Overflow (ft) – Nominal	28.5
Top standpipe (ft) - Nominal	24.1
Second standpipe (ft) - Nominal	20.3
Third standpipe (ft) - Nominal	16.8
Bottom standpipe (ft)	0.5
Passive Containment Ancillary Cooling Water Storage Tank	
Volume (gal) - Nominal	780,000
Design temperature (°F)	125
Design pressure (psig)	Atmospheric
Material	Carbon steel
Water Distribution Bucket	
Volume (gal) - Nominal	42
Design temperature (°F)	150
Design pressure (psig)	Atmospheric
Material	Stainless steel
Water Distribution Collection Troughs and Weirs	
Design temperature (°F)	N/A
Design pressure (psig)	Atmospheric
Material	Stainless steel
Passive Containment Cooling Recirculation Pump	
Quantity	2
Type	Centrifugal
Design capacity (gpm)	135
Design total differential head (ft)	375

Table 6.2.2-3

**FAILURE MODE AND EFFECTS ANALYSIS -
PASSIVE CONTAINMENT COOLING SYSTEM
ACTIVE COMPONENTS**

Component	Failure Mode	PCS Operation Phase	Effect on System Operation	Failure Detection Method	Remarks
Air-operated butterfly valve PCS-PL-V001A (PCS-PL-V001B and motor-operated valve PCS-PL-V001C analogous)	Failure to open on demand	Passive containment cooling water delivery to containment	Failure blocks flow of containment cooling water through one path of PCS which reduces system redundancy. No safety effect on system operation. Minimum containment cooling requirements will be met by the flow of cooling water through operation of one of three flowpaths.	Valve position indication (closed to open position change) in main control room and at the remote shutdown workstation	Valve is normally closed during power operations. Valve opens on actuation by a Hi-2 containment pressure signal or loss of air or loss of 1E power.
Motor-operated gate valve PCS-PL-V002A (PCS-PL-V002B and PCS-PL-V002C analogous)	Spurious valve closure	Passive containment cooling water delivery to containment	Spurious closure blocks flow of containment cooling water through associated flowpath of PCS which reduces system redundancy. No safety effect on system operation. Minimum containment cooling requirements will be met by the flow of cooling water through operation of one of three flowpaths.	Valve position indication (open to closed position change) in main control room and at the remote shutdown workstation	Valve is normally open during power operations. Valve receives confirmatory open signal on Hi-2.
Air-operated butterfly valve PCS-PL-V001A (PCS-PL-V001B and motor-operated valve PCS-PL-V001C analogous)	Spurious valve opening	Normal idle condition	Failure initiates flow of containment cooling water through associated flow path of PCS when not required. No safety effect on system operation. Flow will be terminated through operator action by closing the series isolation valves via the main control room.	Valve position indication (closed to open) in main control room or at the remote shutdown workstation. Also by PCS flow indication and decreasing PCCWST level.	Valve is normally closed during power operations to isolate PCS water.

Table 6.2.3-1 (Sheet 1 of 4)

CONTAINMENT MECHANICAL PENETRATIONS AND ISOLATION VALVES

	Containment Penetration			Isolation Device					Test		
System	Line	Flow	Closed Sys IRC	Valve/Hatch Identification	DCD Subsection	Position N-S-A	Signal	Closure Times	Type[1] & Note	Medium	Direction
CAS	Service air in	In	No	CAS-PL-V204 CAS-PL-V205	9.3.1	C-O-C C-O-C	None None	N/A N/A	C,5	Air	Forward
	Instrument air in	In	No	CAS-PL-V014 CAS-PLV015	9.3.1	O-O-C O-O-C	T None	std. N/A	C,5	Air	Forward
CCS	IRC loads in	In	No	CCS-PL-V200 CCS-PLV201	9.2.2	O-O-C O-O-C	S None	std. N/A	C,5	Air	Forward
	IRC loads out	Out	No	CCS-PLV208 CCS-PLV207	9.2.2	O-O-C O-O-C	SS	std. std.	C,5	Air	Forward
CVS	Spent resin flush out	Out	No	CVS-PL-V041 CVS-PL-V040 CVS-PL-V042	9.3.6	C-C-C C-C-C C-C-C	None None None	N/A N/A N/A	C	Air	Forward
	Letdown	Out	No	CVS-PL-V047 CVS-PL-V045	9.3.6	C-O-C C-O-C	T T	std. std.	C	Air	Forward
	Charging	In	No	CVS-PL-V090 CVS-PL-V091 CVS-PL-V100	9.3.6	C-O-C C-O-C C-C-C	HR,PL2, S+PL1, SGL HR,PL2, S+PL1, SGL None	std. std. N/A	C	Air	Forward
	H2 injection to RCS	In	No	CVS-PL-V092 CVS-PL-V094	9.3.6	C-C-C C-C-C	T None	std. N/A	C	Air	Forward
DWS	Demin. water supply	In	No	DWS-PL-V244 DWS-PL-V245	9.2.4	C-O-C C-O-C	None None	N/A N/A	C,5	Air	Forward
FHS	Fuel transfer	N/A	No	FHS-FT-01	6.2.5	C-O-C	None	N/A	B	Air	Forward
FPS	Fire protection standpipe sys.	In	No	FPS-PL-V050 FPS-PL-V052	9.5.1	C-C-C C-C-C	None None	N/A N/A	C,5	Air	Forward
PSS	RCS/PSX/CVS samples out	Out	No	PSS-PL-V011 PSS-PL-V010A,B	9.3.3	C-C-C C-C-C	T T	std. std.	C	Air	Forward
	Cont. air samples out	Out	No	PSS-PL-V046 PSS-PL-V008	9.3.3	O-C-C O-C-C	T T	std. std.	C	Air	Forward
	RCS/Cont. air sample return	In	No	PSS-PL-V023 PSS-PL-V024	9.3.3	O-C-C O-C-C	T None	std. N/A	C	Air	Forward

Table 6.2.3-1 (Sheet 2 of 4)

CONTAINMENT MECHANICAL PENETRATIONS AND ISOLATION VALVES

System	Containment Penetration			Isolation Device					Test		
	Line	Flow	Closed Sys IRC	Valve/Hatch Identification	DCD Subsection	Position N-S-A	Signal	Closure Times	Type[1] & Note	Medium	Direction
PXS	N_2 to accumulators	In	No	PXS-PL-V042 PXS-PL-V043	6.3	O-O-C C-C-C	T None	std. N/A	C	Air	Forward
RNS	RCS to RHR pump	Out	No	RNS-PL-V002A/B RNS-PL-V023 RNS-PL-V022 RNS-PL-V021 RNS-PL-V061 PXS-PL-V208A	5.4.7 5.4.7 5.4.7 5.4.7 5.4.7 6.3	C-O-C C-O-C C-O-C C-C-C C-O-C C-C-C	HR, S HR, S HR, S None T None	std. std. std. N/A std. N/A	6 C C,4 C C C	Air	-- Reverse Forward Reverse Forward Forward
	RHR pump to RCS	In	No	RNS-PL-V011 RNS-PL-V013	5.4.7	C-O-C C-O-C	HR, S None	std. N/A	C,4 C,4	Air	Forward
SFS	IRWST/Ref. cav. SFP pump discharge	In	No	SFS-PL-V038 SFS-PL-V037	9.1.3	C-O-C C-O-C	T None	std. N/A	C,5	Air	Forward
	IRWST/Ref. cav. purif. out	Out	No	SFS-PL-V035 SFS-PL-V034	9.1.3	C-O-C C-O-C	T T	std. std.	C,5	Air	Forward
SGS	Main steamline 01	Out	Yes	SGS-PL-V040A SGS-PL-V027A[(8)] SGS-PL-V030A,31A,32A SGS-PL-V036A SGS-PL-V240A	10.3	O-C-C O-O-C C-C-C O-O-C C-C-C	MS LSL None MS MS	5 sec std. N/A std. std.	A,2	N_2	Forward
	Main steamline 02	Out	Yes	SGS-PL-V040B SGS-PL-V027B[(8)] SGS-PL-V030B,31B,32B SGS-PL-V036B SGS-PL-V240B	10.3	O-C-C O-O-C C-C-C O-O-C C-C-C	MS LSL None MS MS	5 sec std. N/A std. std.	A,2	N_2	Forward
	Main feedwater 01	In	Yes	SGS-PL-V057A	10.3	O-C-C	MF	5 sec	A,2	H_2O	Forward
	Main feedwater 02	In	Yes	SGS-PL-V057B	10.3	O-C-C	MF	5 sec	A,2	H_2O	Forward
	SG blowdown 01	Out	Yes	SGS-PL-V074A	10.3	O-O-C	PRHR	std.	A,2	H_2O	Forward
	SG blowdown 02	Out	Yes	SGS-PL-V074B	10.3	O-O-C	PRHR	std.	A,2	H_2O	Forward
	Startup feedwater 01	In	Yes	SGS-PL-V067A	10.3	C-O-C	LTC, SGL	std.	A,2	H_2O	Forward
	Startup feedwater 02	In	Yes	SGS-PL-V067B	10.3	C-O-C	LTC, SGL	std.	A,2	H_2O	Forward

Table 6.2.3-1 (Sheet 3 of 4)

CONTAINMENT MECHANICAL PENETRATIONS AND ISOLATION VALVES

	Containment Penetration			Isolation Device					Test		
System	Line	Flow	Closed Sys IRC	Valve/Hatch Identification	DCD Subsection	Position N-S-A	Signal	Closure Times	Type[1] & Note	Medium	Direction
VFS	Cont. air filter supply	In	No	VFS-PL-V003 VFS-PL-V004	9.4.7	C-O-C C-O-C	T, HR,DAS T, HR,DAS	10 sec 10 sec	C,5	Air	Forward Forward
	Cont. air filter exhaust	Out	No	VFS-PL-V010 VFS-PL-V009 VFS-PL-V008	9.4.7	C-O-C C-O-C C-C-C	T,HR,DAS T,HR,DAS N/A	10 sec 10 sec N/A	C,5	Air	Forward Forward Forward
VWS	Fan Coolers out	Out	No	VWS-PL-V086 VWS-PL-V082	9.2.7	O-O-C O-O-C	T T	std. std.	C,3,4,5	Air	Forward
	Fan coolers in	In	No	VWS-PL-V058 VWS-PL-V062	9.2.7	O-O-C O-O-C	T N/A	std. std.	C,3,4,5	Air	Forward
WLS	Reactor coolant drain tank gas	Out	No	WLS-PL-V068 WLS-PL-V067	11.2	C-C-C C-C-C	T T	std. std.	C	Air	Forward
	Normal cont. sump	Out	No	WLS-PL-V057 WLS-PL-V055	11.2	C-C-C C-C-C	T,DAS T,DAS	std. std.	C	Air	Forward
SPARE		N/A	No	P40	6.2.5	C-C-C	N/A	N/A	B	Air	Forward
SPARE		N/A	No	P41	6.2.5	C-C-C	N/A	N/A	B	Air	Forward
SPARE		N/A	No	P42	6.2.5	C-C-C	N/A	N/A	B	Air	Forward
CNS	Main equipment hatch	N/A	No	CNS-MY-Y01	6.2.5	C-C-C	None	N/A	B	Air	Forward
	Maintenance hatch	N/A	No	CNS-MY-Y02	6.2.5	C-C-C	None	N/A	B	Air	Forward
	Personnel hatch	N/A	No	CNS-MY-Y03	6.2.5	C-C-C	None	N/A	B	Air	Forward
	Personnel hatch	N/A	No	CNS-MY-Y04	6.2.5	C-C-C	None	N/A	B	Air	Forward

Table 6.2.3-1 (Sheet 4 of 4)

CONTAINMENT MECHANICAL PENETRATIONS AND ISOLATION VALVES

Explanation of Heading and Acronyms for Table 6.2.3-1

System: Fluid system penetrating containment

Containment Penetration: These fields refer to the penetration itself

Line: Fluid system line
Flow: Direction of flow in or out of containment
Closed Sys IRC: Closed system inside containment as defined in DCD Section 6.2.3.1.1

Isolation Device: These fields refer to the isolation devices for a given penetration
Valve/Hatch ID: Identification number on P&ID or system figure

Subsection Containing Figure: Safety analysis report containing the system P&ID or figure
Position N-S-A: Device position for N (normal operation)
S (shutdown)
A (post-accident)

Signal: Device closure signal

- MS: Main steamline isolation
- LSL: Low steamline pressure
- MF: Main feedwater isolation
- LTC: Low T_{cold}
- PRHR: Passive residual heat removal actuation
- T: Containment isolation
- S: Safety injection signal
- HR: High containment radiation
- DAS: Diverse actuation system signal
- PL2: High 2 pressurizer level signal
- S+PL1: Safety injection signal plus high 1 pressurizer level
- SGL: High steam generator level

Closure Time:
Required valve closure stroke time
- std: Industry standard for valve type (≤ 60 seconds)
- N/A: Not Applicable

Test: These fields refer to the penetration testing requirements

Type: Required test type
- A: Integrated Leak Rate Test
- B: Local Leak Rate Test -- penetration
- C: Local Leak Rate Test -- fluid systems

Note: See notes below
Medium: Test fluid on valve seat
Direction: Pressurization direction
- Forward: High pressure on containment side
- Reverse: High pressure on outboard side

Notes:

1. Containment leak rate tests are designated Type A, B, or C according to 10CFR50, Appendix J.
2. The secondary side of the steam generator, including main steam, feedwater, startup feedwater, blowdown and sampling piping from the steam generators to the containment penetration, is considered an extension of the containment. These systems are not part of the reactor coolant pressure boundary and do not open directly to the containment atmosphere during post-accident conditions. During Type A tests, the secondary side of the steam generators is vented to the atmosphere outside containment to ensure that full test differential pressure is applied to this boundary.
3. The central chilled water system remains water-filled and operational during the Type A test in order to maintain stable containment atmospheric conditions.
4. The containment isolation valves for this penetration are open during the Type A test to facilitate testing. Their leak rates are measured separately.
5. The inboard valve flange is tested in the reverse direction.
6. These valves are not subject to a Type C test. Upstream side of RNS hot leg suction isolation valves is not vented during local leak rate test to retain double isolation of RCS at elevated pressure. Valve is flooded during post accident operation.
7. The inboard globe valve is tested in the reverse direction. The test is conservative since the test pressure tends to unseat the valve disc, whereas containment pressure would tend to seat the disc.
8. Refer to DCD Table 15.0-4b for PORV block valve closure time.

Table 6.2.4-1

COMPONENT DATA - HYDROGEN SENSORS (NOMINAL)

Number	3
Range (% hydrogen)	0 - 20
Response time	90% in 10 seconds

Table 6.2.4-2

COMPONENT DATA - HYDROGEN RECOMBINER (NOMINAL)

Number Full Size PAR	 2
Average efficiency (percent)	85
Depletion rate	Reference 19

Table 6.2.4-3

COMPONENT DATA - HYDROGEN IGNITER (NOMINAL)

Number	64
Surface Temperature (°F)	1600 to 1700

Tables 6.2.4-4 and 6.2.4-5 not used.

Table 6.2.4-6 (Sheet 1 of 3)

IGNITER LOCATION

Criteria

- A sufficient number of igniters are placed in the major transport paths (including dominant natural circulation pathways) of hydrogen so that hydrogen can be burned continuously close to the release point. This prevents hydrogen from preferentially accumulating in a certain region of the containment.

- Igniters (minimum of 2) are located in major regions or compartments where hydrogen may be released, through which it may flow, or where it may accumulate.

- It is preferable to ignite a hydrogen-air mixture at the bottom so that upward flame propagation can be promoted at lean hydrogen concentrations. Igniters within each subcompartment are located in the vicinity of, and above, the highest potential release location within the subcompartment.

- In compartments with relatively small openings in the ceiling, the potential may exist for the hydrogen-air mixture to rise and to collect near the ceiling. Therefore, one or more igniters are placed near the ceiling of such compartments. Igniter coverage is provided within the upper 10 percent of the vertical height subcompartments or 10 feet from the ceiling whichever is less. In cases where the highest potential release point is low in the compartment, both this and the previous criteria are considered.

- To the extent possible, igniters are placed away from walls and other large surfaces so that a flame front created by ignition at the bottom of a compartment can travel unimpeded up to the top.

- A sufficient number of igniters are installed in long, narrow compartments (corridors) so that the flame fronts created by the igniters need to travel only a limited distance before they merge. This limits the potential for significant flame acceleration.

- Igniter coverage is provided to control combustion in areas where oxygen rich air may enter into an inerted region with combustible hydrogen levels during an accident scenario.

- Igniters are located above the flood level, if possible. Those which may be flooded have redundant fuses to protect the power supply.

- In locations where the potential hydrogen release location can be defined, i.e. above the IRWST spargers, at IRWST vents, etc igniter coverage is provided as close to the source as feasible.

- Provisions for installation, maintenance, and testing are to be considered.

Table 6.2.4-6 (Sheet 2 of 3)

IGNITER LOCATION

Implementation

- **Reactor Cavity –** Hydrogen releases within the reactor cavity will flow either through the vertical access tunnel, through the opening around the RCS hot and cold legs into the loop compartments or if the refueling cavity seal ring fails then potentially through the refueling cavity. The potential flow paths have at least four igniters with at least two powered by each of two power groups. No igniters have been located within the reactor cavity since this region would always be flooded, adequate igniter coverage is available in hydrogen pathways from the reactor cavity and any maintenance or inspection would result in elevated personnel exposure.

- **Loop Compartments –** Hydrogen releases from the hot or cold legs or from the reactor cavity would flow up through the loop compartment to the dome region. Igniter coverage provided within the loop compartment consists of a total of four igniters at two different elevations covering the perimeter of the compartment and with two igniters powered by one power group and two by the second power group. Additional coverage is provided above the loop compartments at elevation 162′ with four igniters above each loop compartment and powered by different power groups.

- **Pressurizer Compartment –** Hydrogen releases within the pressurizer compartment would flow up through the compartment toward the dome region. Igniter coverage is provided within the compartment consists of a total of four igniters at two different elevations covering the perimeter of the compartment with two igniters powered by one power group and two by the second power group. Additional coverage is provided above the pressurizer compartment at elevation 162′ with two igniters above powered by different power groups.

- **Tunnel Connection Loop Compartments –** The tunnel between the loop compartments and extending downward into the reactor coolant drain tank cavity is provided with four igniters for hydrogen control. Releases within the reactor cavity or from the loop compartment may flow through this vertical access tunnel. Igniter coverage is provided over the width of the tunnel at three separate elevations and is powered by different power groups.

- **Refueling Cavity –** Hydrogen releases from the reactor cavity or from the potentially from the reactor coolant loops may flow up past the refueling cavity seal ring and through the refueling cavity to the dome region. Igniter coverage provided within the refueling consists of a total of four igniters at two different elevations covering the perimeter of the compartment with two igniters powered by one power group and two by the second power group. Additional coverage is provided above the refueling cavity at elevation 162′ with four igniters powered by different power groups.

- **Southeast Valve and Accumulator Rooms –** Hydrogen releases within the southeast valve or accumulator rooms will rise with the mass and energy releases to near the ceiling and exit either through the stairwell on the west wall or through piping penetration holes in the ceiling. The hydrogen control protection is provided by two igniters, one located near the ceiling of each of the adjoining rooms. The igniters are powered by different power groups and provide backup control for each other.

Table 6.2.4-6 (Sheet 3 of 3)

IGNITER LOCATION

- **East Valve, Northeast Accumulator, and Northeast Valve Room –** Hydrogen releases within the east valve, northeast accumulator or valve rooms will rise with the mass and energy releases to near the ceiling and exit either through the enlarged vent area surrounding the discharge piping from the core makeup tank located at the 107′ 2″ elevation and through other piping penetration holes in the ceiling. The hydrogen control protection is provided by three igniters, one located near the ceiling of each of the adjoining rooms. The igniters are powered by different power groups and provide backup control for each other.

- **North CVS Equipment Room –** Hydrogen releases within the CVS equipment room will rise from the piping or equipment located on the CVS module to near the ceiling, pass over the outer barrier wall and flow up through the stairwell or ceiling grating. Hydrogen control is provided by two igniters located near the ceiling of the equipment room between the equipment module and the major relief paths from the compartment. The igniters are powered by different power groups.

- **IRWST –** Hydrogen releases into the IRWST are controlled by the distribution of igniters internal to the IRWST and within the vents from and into the IRWST. Two igniters on different power groups are located within the IRWST below the tank roof of the IRWST and above the spargers. In the event of hydrogen releases via the spargers, the igniters directly above the release points will provide the most immediate point of recombination. Should the environment within the IRWST be inerted or otherwise not be ignited by the assemblies above the sparger, the hydrogen will be ignited as it exhausts from the IRWST at any of four of the vents fitted with igniter assemblies. Two of the four igniters are powered by one power group and two by the second power group. Finally, in the event that the IRWST is hydrogen rich and air is drawn into the IRWST the mixture will become flammable. In order to provide this recombination, the two inlet vents on the other side of the IRWST from the sparger and primary exhaust vents are fitted an igniter each.

- **Lower Compartment Area –** Hydrogen releases within the lower compartment will rise with the mass and energy releases to near the ceiling and exit either through the north stairwell or along the circumferential gap between the operating deck and the containment shell. The hydrogen control protection is provided by eleven igniters spread over the potential release areas and located either just above the mezzanine deck elevation or near the ceiling. This approach provides wide coverage over the entire compartment area at two separate elevations. The igniters are split between the two separate power groups.

- **Upper Compartment –** Hydrogen control is provided at three separate levels within the upper compartment. At the 162-176 foot elevations, 10 igniters are distributed over the area primarily above the major release flow paths including the loop compartments, refueling cavity, pressurizer compartment and above the stairwell from the lower compartment area. The igniters are split between the two power groups. At 228 foot elevation, an igniter is provided in each quadrant at the mid region of the upper compartment with two igniters on each of the two power groups. At the upper region elevation 257 four additional igniters are located to initiate recombination of hydrogen not ignited at either the source or along its flow path. The four igniters are split between the two power groups.

Table 6.2.4-7

SUBCOMPARTMENT/AREA IGNITER COVERAGE

	Igniter Coverage (Elevation)[1]	
Subcompartment	**Power Group 1**	**Power Group 2**
Reactor Cavity	1(El 91′) 3 (El 95′) 13, 5, 55 (El 120′) 58 (El 132′) 8, 12 (El 139′)	4 (El 95′) 2 (El 99′) 11, 7, 56 (El 120′) 57 (El 132′) 6, 14 (El 139′)
Loop Compartment 01	13 (El 120′) 12 (El 139′)	11 (El 120′) 14 (El 139′)
Loop Compartment 02	5 (El 120′) 8 (El 139′)	7 (El 120′) 6 (El 139′)
Pressurizer Compartment	49 (El 154′) 60 (El 135′)	50 (El 154′) 59 (El 135′)
Tunnel connecting Loop Compartments	1 (El 91′) 3 (El 95′) 31 (El 120′)	4 (El 95′) 2 (El 99′) 30 (El 120′)
Southeast Valve Room	21 (El 105′)	20 (El 105′)
Southeast Accumulator Room	21 (El 105′)	20 (El 105′)
East Valve Room	18 (El 105′)	19 (El 105′)
Northeast Accumulator Room	18 (El 105′)	17, 19 (El 105′)
Northeast Valve Room	18 (El 105′)	17 (El 105′)
North CVS Equipment Room	34 (El 105′)	33 (El 105′)
Lower Compartment Area (CMT and Valve area)	22 (El 133′) 27, 28, 29, 31, 32 (El 120′)	23, 24, 25 (El 133′) 26, 30 (El 120′)
IRWST Compartment	35, 37 (El 135′)	36, 38 (El 135′)
IRWST Interior	9 (El 133′)	10 (El 133′)
IRWST Inlet	16 (El 133′)	15 (El 133′)
Refueling Cavity	55 (El 120′) 58 (El 132′)	56 (El 120′) 57 (El 132′)
Upper Compartment		
Lower Region	39, 42, 44, 43, 47 (El 162′-176′)	40, 41, 45, 46, 48 (El 162′-176′)
Mid Region	51, 54 (El 228′)	52, 53 (El 228′)
Upper Region	61, 63 (El 257′)	62, 64 (El 257′)

Note:
1. Elevations are approximate.

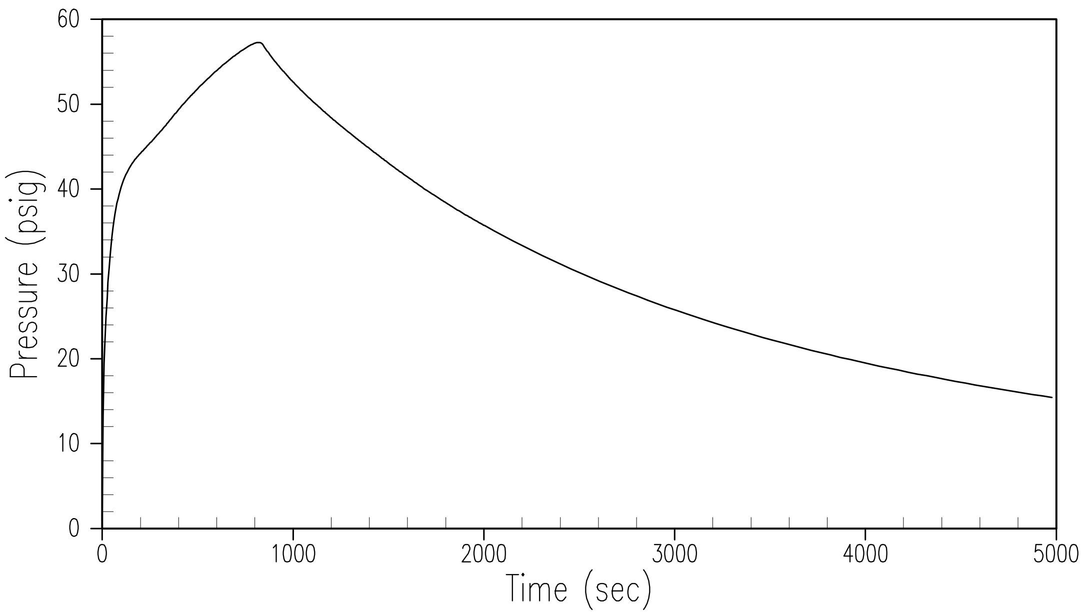


Figure 6.2.1.1-1

AP1000 Containment Response for Full DER MSLB – 30% Power

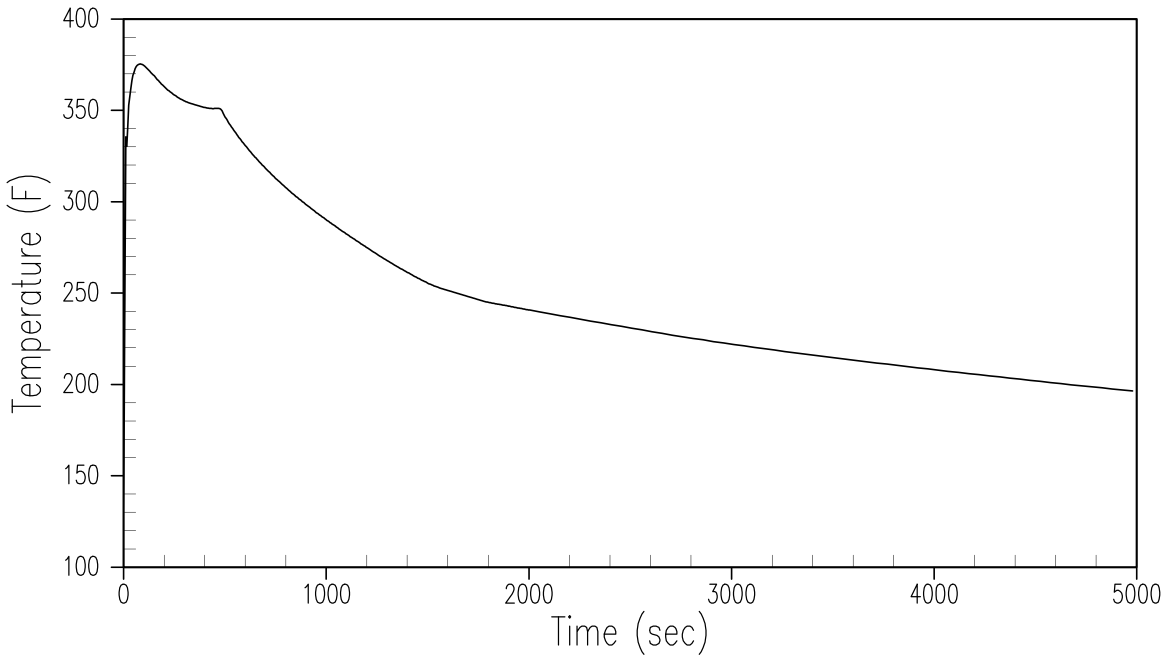


Figure 6.2.1.1-2

AP1000 Containment Response for Full DER MSLB – 101% Power

Figures 6.2.1.1-3 and 6.2.1.1-4 not used.

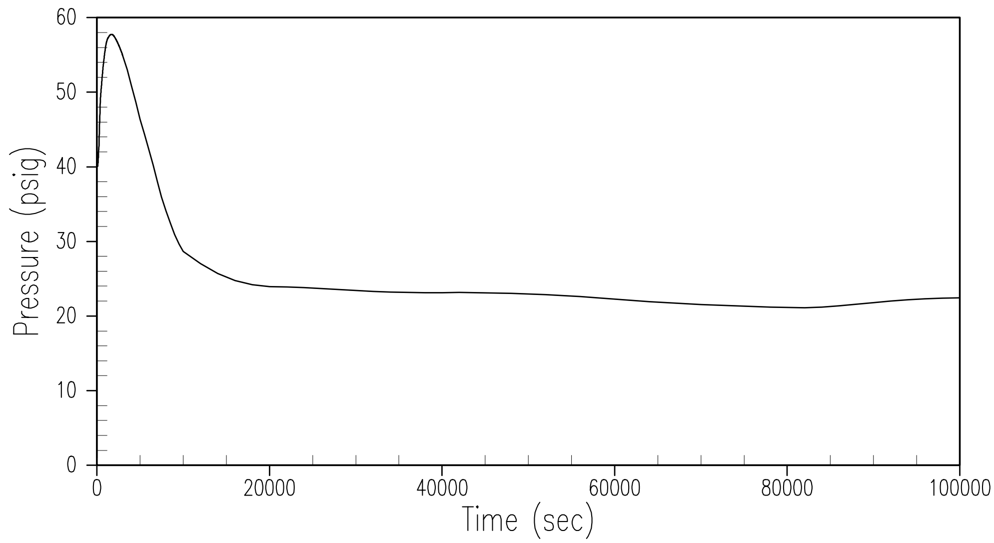


Figure 6.2.1.1-5

AP1000 Containment Pressure Response for DECLG LOCA

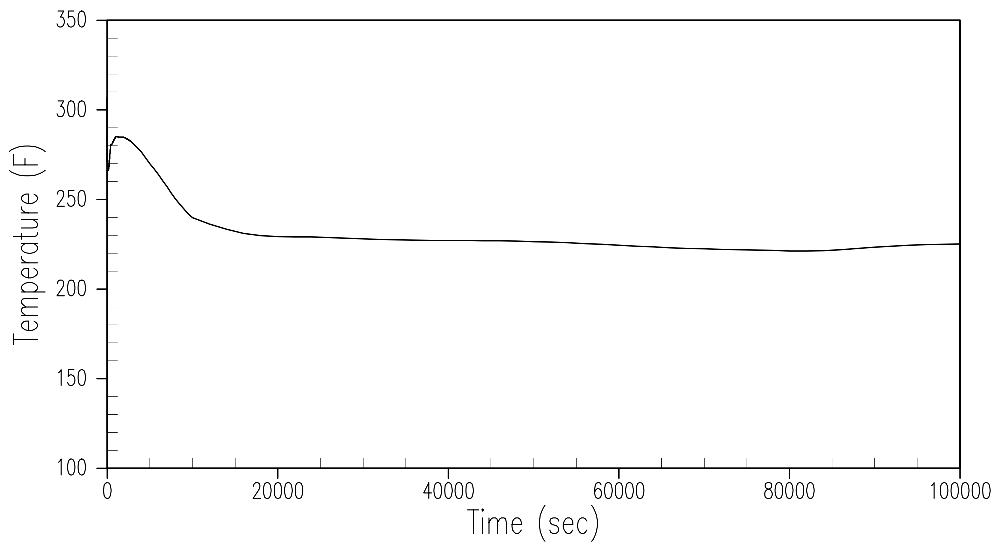


Figure 6.2.1.1-6

AP1000 Containment Temperature Response to DECLG LOCA

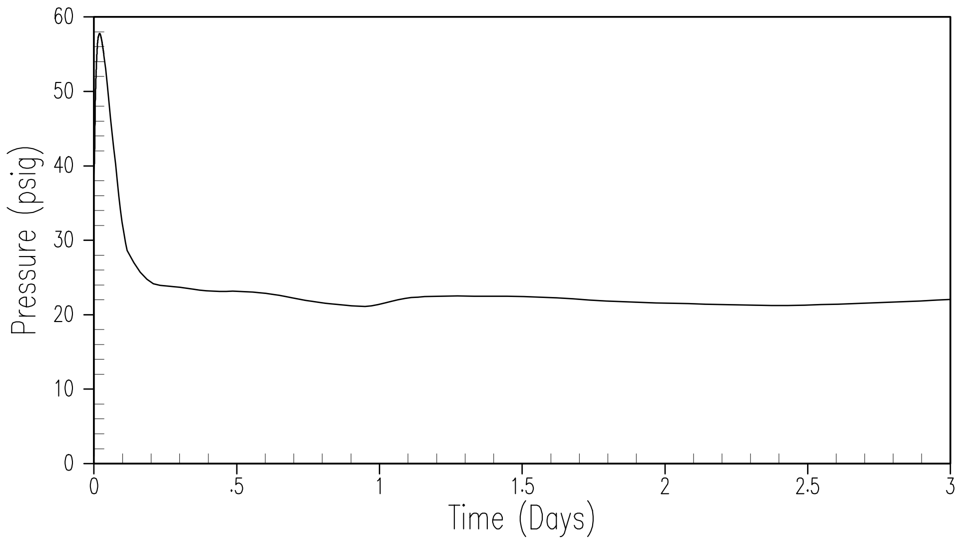


Figure 6.2.1.1-7

AP1000 Containment Pressure Response for DECLG LOCA – 3 Days

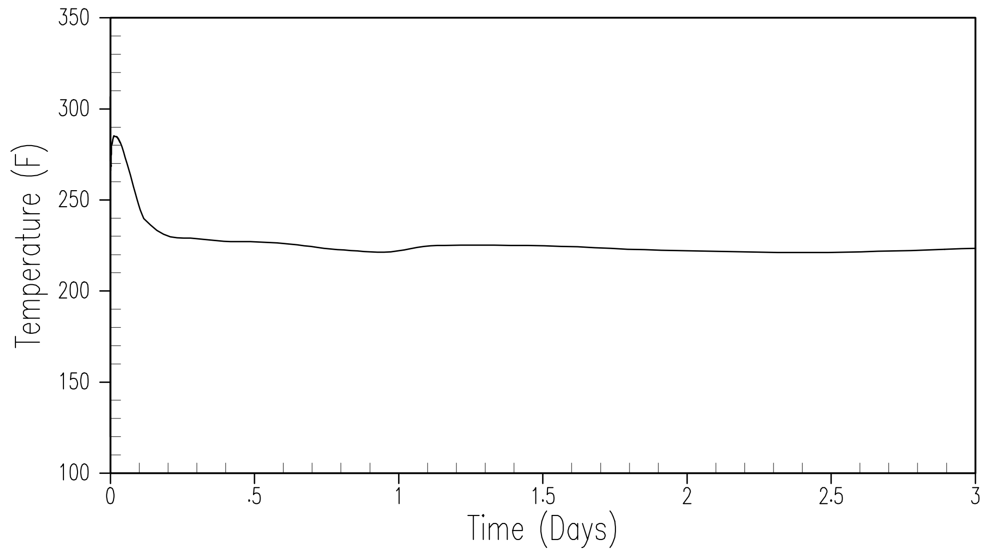


Figure 6.2.1.1-8

AP1000 Containment Temperature Response for DECLG LOCA – 3 Days

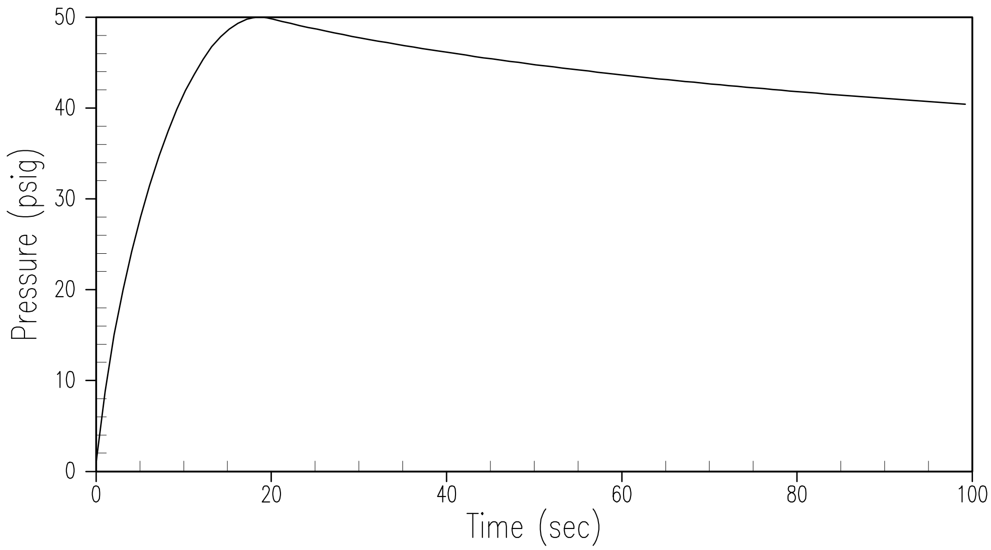


Figure 6.2.1.1-9

AP1000 Containment Pressure Response – DEHLG LOCA

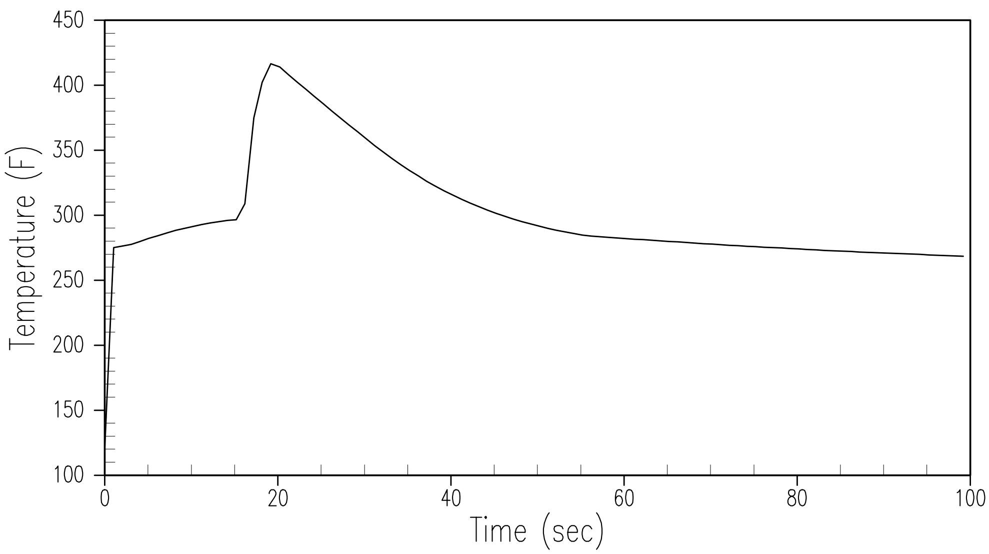


Figure 6.2.1.1-10

AP1000 Containment Response for DEHLG LOCA

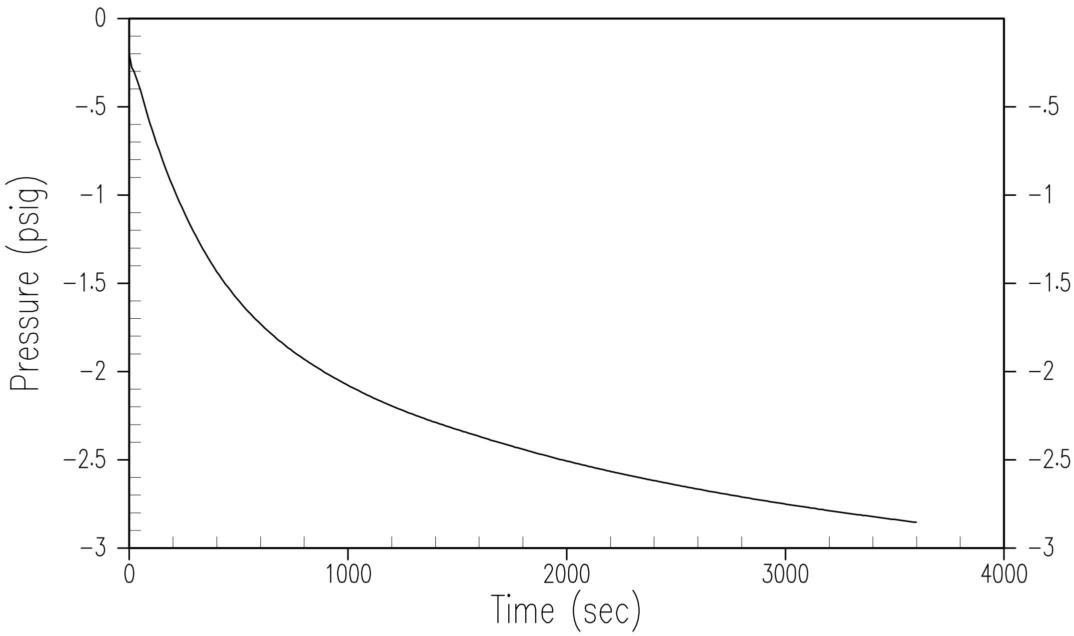


Figure 6.2.1.1-11

AP1000 External Pressure Analysis Containment Pressure vs. Time

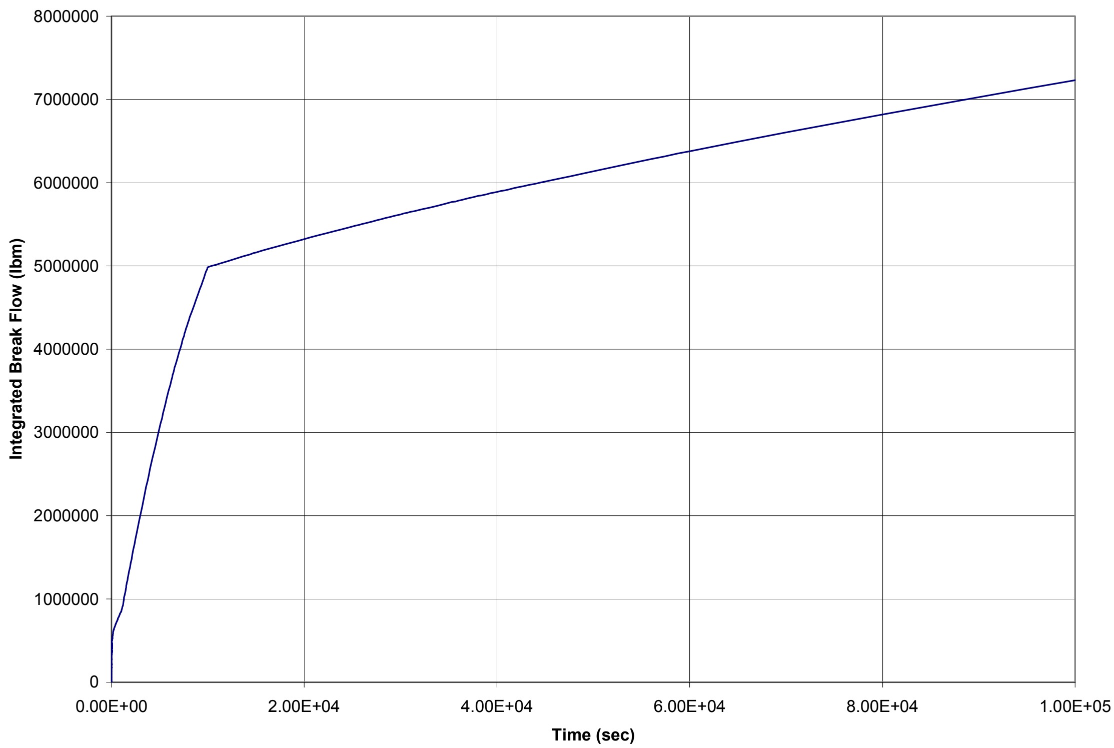


Figure 6.2.1.3-1

AP1000 DECLG Integrated Break Flow

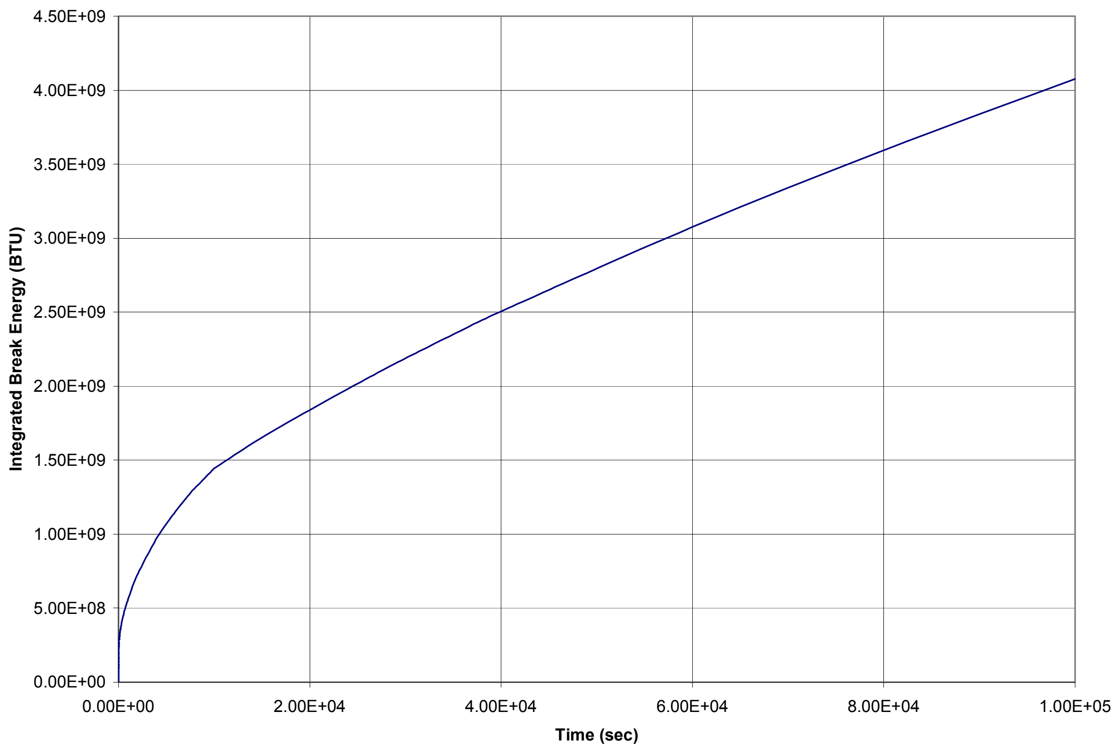


Figure 6.2.1.3-2

AP1000 DECLG LOCA Integrated Energy Released

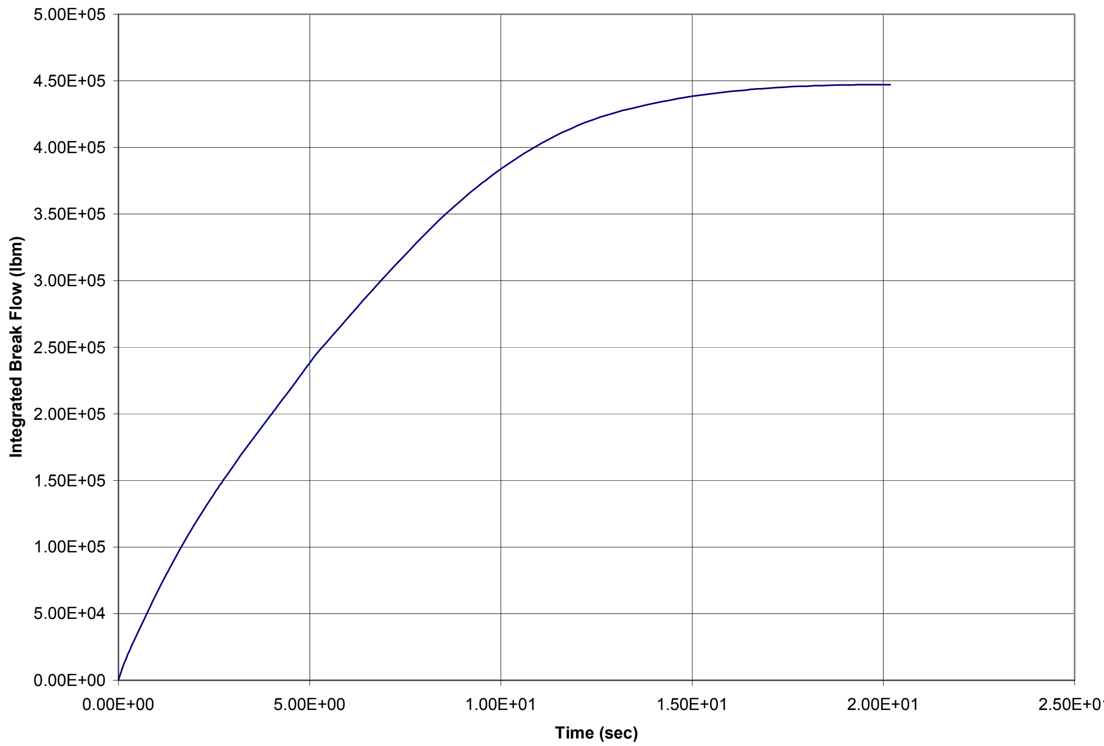


Figure 6.2.1.3-3

AP1000 DEHLG Integrated Break Flow

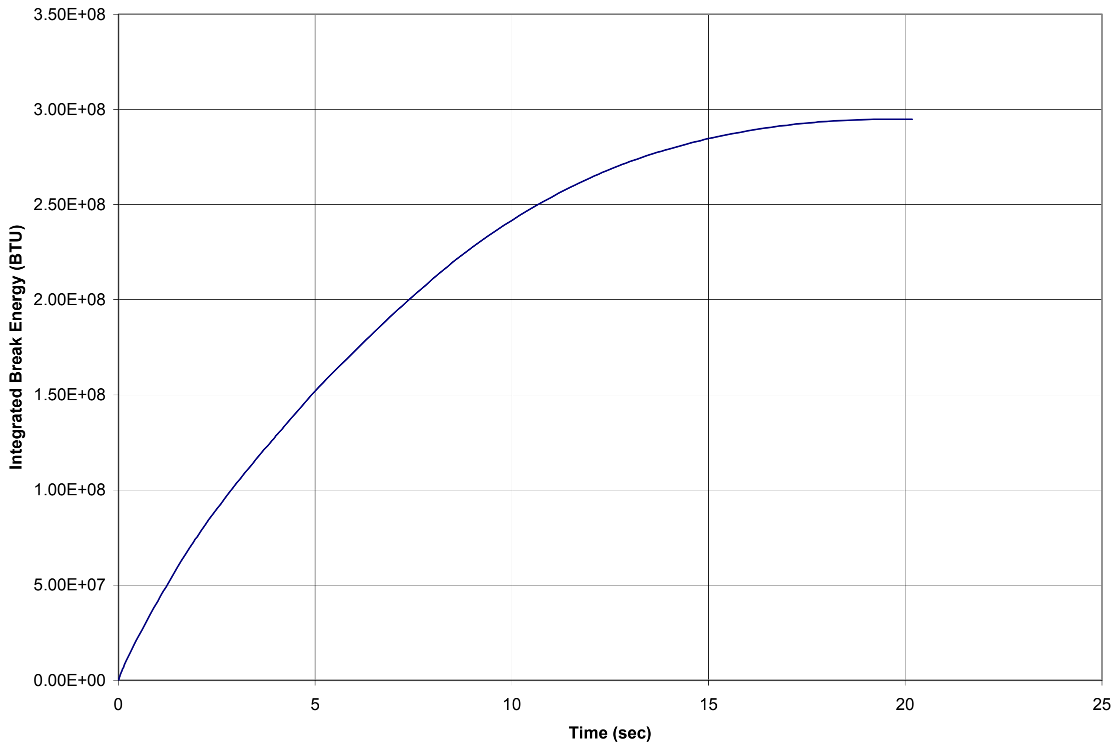


Figure 6.2.1.3-4

AP1000 DEHLG LOCA Integrated Energy Released

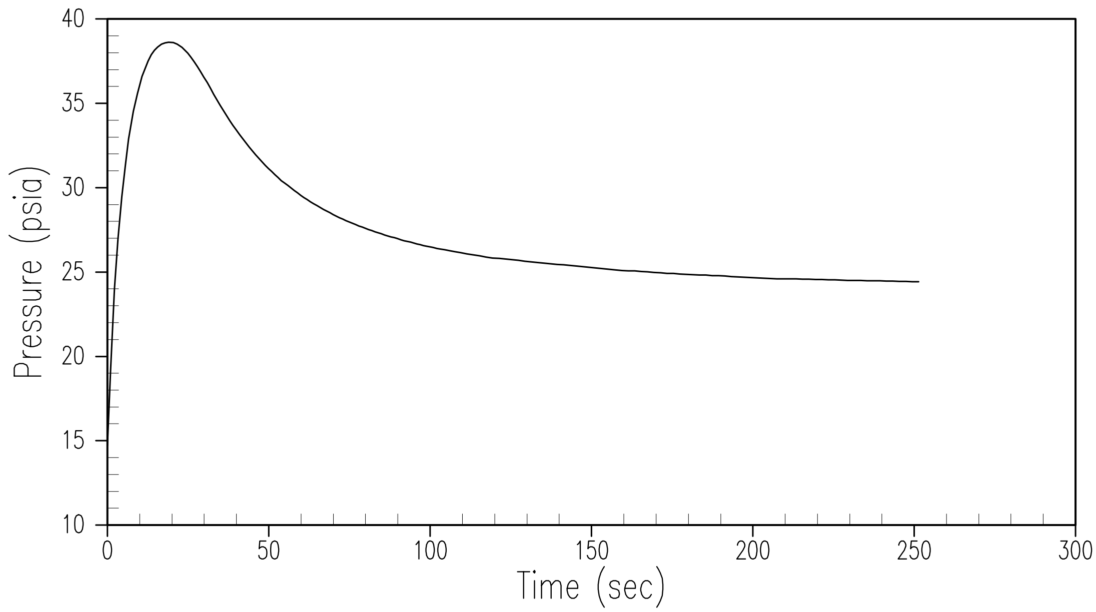
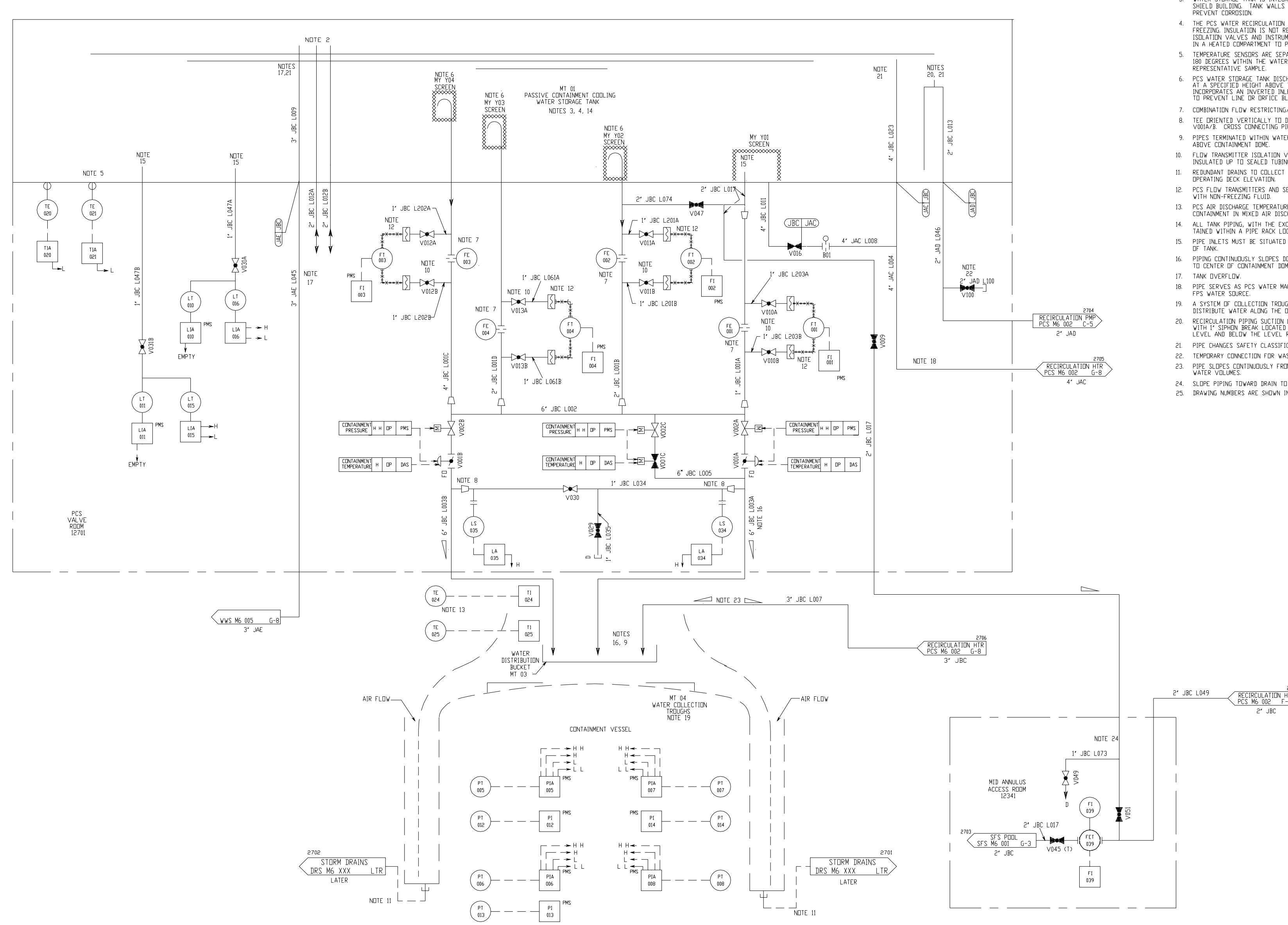


Figure 6.2.1.5-1

AP1000 Minimum Containment Pressure for DECLG LOCA

[This page intentionally blank]



NOTES:

1. THE SYSTEM LOCATOR CODE "APP-PCS" HAS BEEN OMITTED FROM ALL COMPONENT NUMBERS. THE COMPONENT CODE HAS BEEN OMITTED FROM ALL COMPONENTS EXCEPT EQUIPMENT. REFER TO THE P&ID LEGEND DRAWING APP-GW-M6-001, 002 AND 003 FOR ADDITIONAL INFORMATION REGARDING COMPONENT NUMBERING.
2. VENT PIPE ELEVATION MUST BE ABOVE OVERFLOW PIPE ELEVATION.
3. WATER STORAGE TANK IS INTEGRAL TO THE TOP OF THE CONTAINMENT SHIELD BUILDING. TANK WALLS ARE STAINLESS STEEL LINED TO PREVENT CORROSION.
4. THE PCS WATER RECIRCULATION LINES ARE INSULATED TO PREVENT FREEZING. INSULATION IS NOT REQUIRED FOR VENT, DRAIN AND ISOLATION VALVES AND INSTRUMENTATION WHICH ARE LOCATED IN A HEATED COMPARTMENT TO PREVENT FREEZING.
5. TEMPERATURE SENSORS ARE SEPARATED BY APPROXIMATELY 180 DEGREES WITHIN THE WATER STORAGE TANK TO PROVIDE REPRESENTATIVE SAMPLE.
6. PCS WATER STORAGE TANK DISCHARGE LINES ARE EACH TERMINATED AT A SPECIFIED HEIGHT ABOVE THE TANK BOTTOM. EACH PIPE INCORPORATES AN INVERTED INLET AND IS ENCLOSED WITHIN A SCREEN TO PREVENT LINE OR ORFICE BLOCKAGE.
7. COMBINATION FLOW RESTRICTING/FLOW MEASUREMENT ORIFICE.
8. TEE ORIENTED VERTICALLY TO DETECT VALVE WATER LEAKAGE FROM V001A/B. CROSS CONNECTING PIPING CONFIGURED TO DRAIN LEAKAGE.
9. PIPES TERMINATED WITHIN WATER DISTRIBUTION BUCKET SUSPENDED ABOVE CONTAINMENT DOME.
10. FLOW TRANSMITTER ISOLATION VALVES AND IMPULSE PIPING INSULATED UP TO SEALED TUBING.
11. REDUNDANT DRAINS TO COLLECT EXCESS PCS WATER AT OPERATING DECK ELEVATION.
12. PCS FLOW TRANSMITTERS AND SENSING LINES ARE FILLED WITH NON-FREEZING FLUID.
13. PCS AIR DISCHARGE TEMPERATURE ELEMENTS LOCATED ABOVE CONTAINMENT IN MIXED AIR DISCHARGE STREAM.
14. ALL TANK PIPING, WITH THE EXCEPTION OF THE DRAIN PENETRATIONS, ARE CONTAINED WITHIN A PIPE RACK LOCATED INSIDE THE TANK ALONG ITS OUTER WALL.
15. PIPE INLETS MUST BE SITUATED SIX INCHES ABOVE BOTTOM OF TANK.
16. PIPING CONTINUOUSLY SLOPES DOWNWARD FROM VALVES V001A/B TO CENTER OF CONTAINMENT DOME.
17. TANK OVERFLOW.
18. PIPE SERVES AS PCS WATER MAKEUP LINE AS WELL AS EMERGENCY FPS WATER SOURCE.
19. A SYSTEM OF COLLECTION TROUGHS AND WEIRS SERVES TO EVENLY DISTRIBUTE WATER ALONG THE OUTER CONTAINMENT SHELL SURFACE.
20. RECIRCULATION PIPING SUCTION LINE TERMINATES NEAR TANK BOTTOM WITH 1" SIPHON BREAK LOCATED ABOVE THE MINIMUM REQUIRED PCCWST LEVEL AND BELOW THE LEVEL REQUIRED FOR MINIMUM FIRE WATER VOLUME.
21. PIPE CHANGES SAFETY CLASSIFICATION AT TANK PENETRATION POINT.
22. TEMPORARY CONNECTION FOR WASHDOWN OF CONTAINMENT VESSEL.
23. PIPE SLOPES CONTINUOUSLY FROM A SINGLE HIGH POINT TO AVOID ANY TRAPPED WATER VOLUMES.
24. SLOPE PIPING TOWARD DRAIN TO AVOID POTENTIAL FOR FREEZING.
25. DRAWING NUMBERS ARE SHOWN IN INTERFACE FLAGS WITHOUT PREFIX "APP",

Figure 6.2.2-1 (Sheet 1 of 2)

Passive Containment Cooling System
Piping and Instrumentation Diagram
(REF) PCS 001

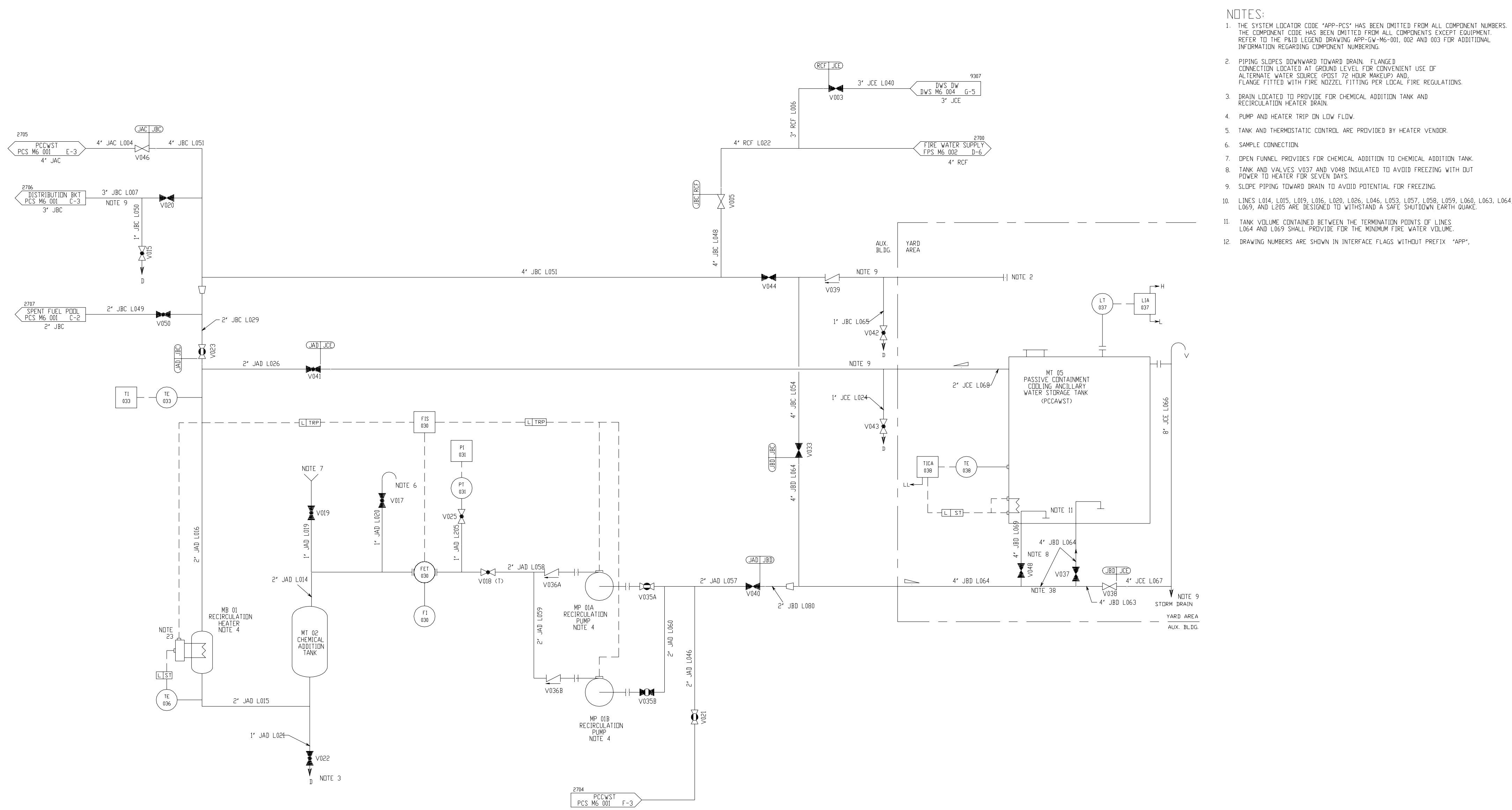


Figure 6.2.2-1 (Sheet 2 of 2)

Passive Containment Cooling System
Piping and Instrumentation Diagram
(REF) PCS 002

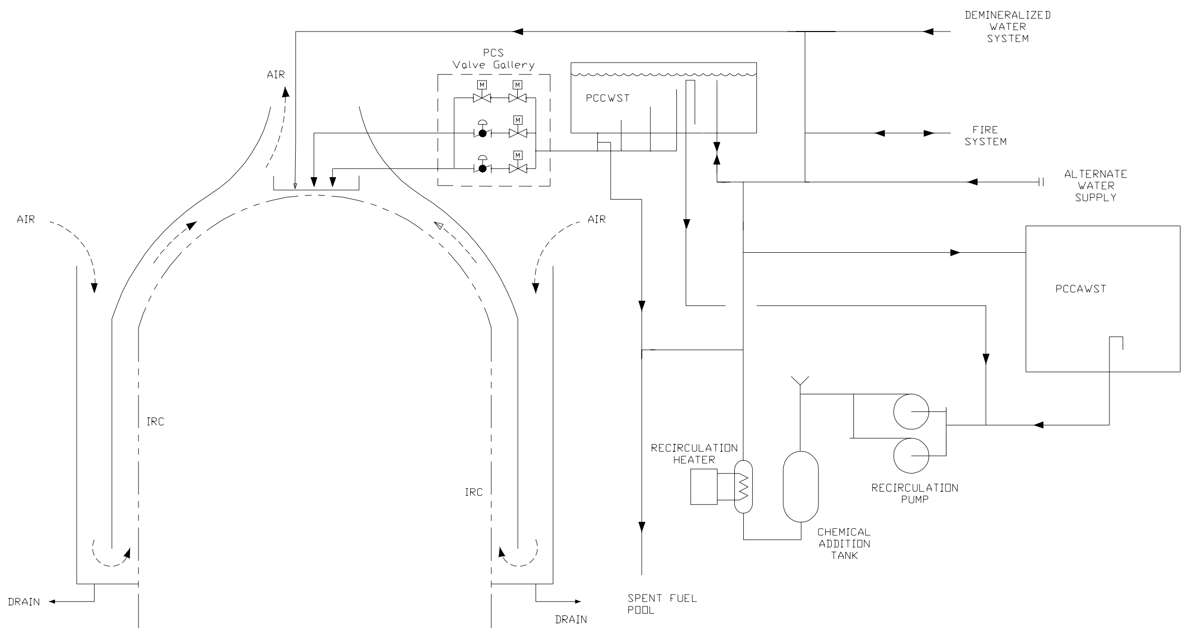


Figure 6.2.2-2

Simplified Sketch of Passive Containment Cooling System

Figures 6.2.4-1 through 6.2.4-4 not used.

Withheld under 10 CFR 2.390.

Figure 6.2.4-5

Hydrogen Igniter Locations – Section View

Withheld under 10 CFR 2.390.

Figure 6.2.4-6

Hydrogen Igniter Locations
Plan View Elevation 82′-6″

Withheld under 10 CFR 2.390.

Figure 6.2.4-7

Hydrogen Igniter Locations – Section View

Withheld under 10 CFR 2.390.

Figure 6.2.4-8

Hydrogen Igniter Locations
Plan View Elevation 96′-6″

Withheld under 10 CFR 2.390.

Figure 6.2.4-9

Hydrogen Igniter Locations
Plan View Elevation 118′-6″

Withheld under 10 CFR 2.390.

Figure 6.2.4-10

Hydrogen Igniter Locations
Plan View Elevation 135′-3″

Withheld under 10 CFR 2.390.

Figure 6.2.4-11

Hydrogen Igniter Locations
Plan View Elevation 162′-0″

Withheld under 10 CFR 2.390.

Figure 6.2.4-12

Hydrogen Igniter Locations
Plan View Elevation 210′-0″

Withheld under 10 CFR 2.390.

Figure 6.2.4-13

Hydrogen Igniter Locations Section A-A

[This page intentionally blank]

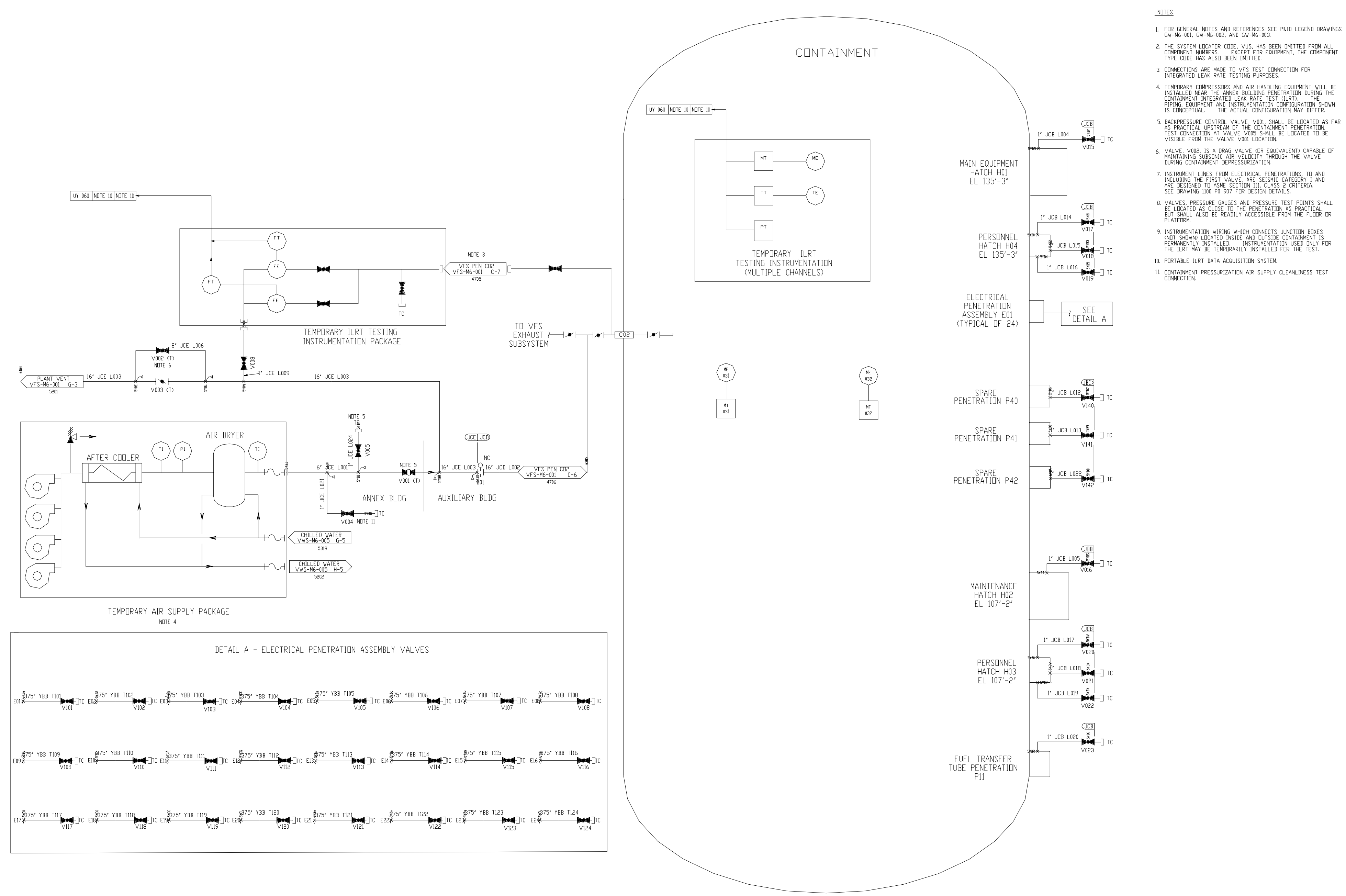


Figure 6.2.5-1

Containment Leak Rate Test System
Piping and Instrumentation Diagram

6.3 Passive Core Cooling System

The primary function of the passive core cooling system is to provide emergency core cooling following postulated design basis events. To accomplish this primary function, the passive core cooling system is designed to perform the following functions:

- Emergency core decay heat removal

  Provide core decay heat removal during transients, accidents or whenever the normal heat removal paths are lost. This heat removal function is available at reactor coolant system conditions including shutdowns. During refueling operations, when the IRWST is drained into the refueling cavity, other passive means of core decay heat removal are utilized. Subsection 6.3.3.4.4 provides a description of how this is accomplished.

- Reactor coolant system emergency makeup and boration

  Provide reactor coolant system makeup and boration during transients or accidents when the normal reactor coolant system makeup supply from the chemical and volume control system is unavailable or is insufficient.

- Safety injection

  Provide safety injection to the reactor coolant system to provide adequate core cooling for the complete range of loss of coolant accidents, up to and including the double-ended rupture of the largest primary loop reactor coolant system piping.

- Containment pH control

  Provide for chemical addition to the containment during post-accident conditions to establish floodup chemistry conditions that support radionuclide retention with high radioactivity in containment and to prevent corrosion of containment equipment during long-term floodup conditions.

The passive core cooling system is designed to operate without the use of active equipment such as pumps and ac power sources. The passive core cooling system depends on reliable passive components and processes such as gravity injection and expansion of compressed gases. The passive core cooling system does require a one-time alignment of valves upon actuation of the specific components.

6.3.1 Design Basis

The passive core cooling system is designed to perform its safety-related functions based on the following considerations:

- It has component redundancy to provide confidence that its safety-related functions are performed, even in the unlikely event of the most limiting single failure occurring coincident with postulated design basis events.

- Components are designed and fabricated according to industry standard quality groups commensurate with its intended safety-related functions.
- It is tested and inspected at appropriate intervals, as defined by the ASME Code, Section XI, and by technical specifications.
- It performs its intended safety-related functions following events such as fire, internal missiles or pipe breaks.
- It is protected from the effects of external events such as earthquakes, tornadoes, and floods.
- It is designed to be sufficiently reliable, considering redundancy and diversity, to support the plant core melt frequency and significant release frequency goals.

6.3.1.1 Safety Design Basis

The passive core cooling system is designed to provide emergency core cooling during events involving increases and decreases in secondary side heat removal and decreases in reactor coolant system inventory. Subsection 6.3.3 provides a description of the design basis events. The performance criteria are provided in subsection 6.3.1 and also described in Chapter 15, under the respective event sections.

6.3.1.1.1 Emergency Core Decay Heat Removal

For postulated non-LOCA events, where a loss of capability to remove core decay heat via the steam generators occurs, the passive core cooling system is designed to perform the following functions:

- The passive residual heat removal heat exchanger automatically actuates to provide reactor coolant system cooling and to prevent water relief through the pressurizer safety valves.
- The passive residual heat removal heat exchanger is capable of automatically removing core decay heat following such an event, assuming the steam generated in the in-containment refueling water storage tank is condensed on the containment vessel and returned by gravity via the in-containment refueling water storage tank condensate return gutter.
- The passive residual heat removal heat exchanger, in conjunction with the passive containment cooling system, is designed to remove decay heat for an indefinite time in a closed-loop mode of operation. The passive residual heat removal heat exchanger is designed to cool the reactor coolant system to 420°F in 36 hours, with or without reactor coolant pumps operating. This allows the reactor coolant system to be depressurized and the stress in the reactor coolant system and connecting pipe to be reduced to low levels. This also allows plant conditions to be established for initiation of normal residual heat removal system operation.
- During a steam generator tube rupture event, the passive residual heat removal heat exchanger removes core decay heat and reduces reactor coolant system temperature and

pressure, equalizing with steam generator pressure and terminating break flow, without overfilling the steam generator.

6.3.1.1.2 Reactor Coolant System Emergency Makeup and Boration

For postulated non-LOCA events, sufficient core makeup water inventory is automatically provided to keep the core covered and to allow for decay heat removal. In addition, this makeup prevents actuation of the automatic depressurization system for a significant time.

For postulated events resulting in an inadvertent cooldown of the reactor coolant system, such as a steam line break, sufficient borated water is automatically provided to makeup for reactor coolant system shrinkage. The borated water also counteracts the reactivity increase caused by the resulting system cooldown.

For a Condition II steam line break described in Chapter 15, return to power is acceptable if there is no core damage. For this event, the automatic depressurization system is not actuated.

For a large steam line break, the peak return to power is limited so that the offsite dose limits are satisfied. Following either of these events, the reactor is automatically brought to a subcritical condition.

For safe shutdown, the passive core cooling system is designed to supply sufficient boron to the reactor coolant system to maintain the technical specification shutdown margin for cold, post-depressurization conditions, with the most reactive rod fully withdrawn from the core. The automatic depressurization system is not expected to actuate for these events.

6.3.1.1.3 Safety Injection

The passive core cooling system provides sufficient water to the reactor coolant system to mitigate the effects of a loss of coolant accident. In the event of a large loss of coolant accident, up to and including the rupture of a hot or cold leg pipe, where essentially all of the reactor coolant volume is initially displaced, the passive core cooling system rapidly refills the reactor vessel, refloods the core, and continuously removes the core decay heat. A large break is a rupture with a total cross-sectional area equal to or greater than one square foot. Although the criteria for mechanistic pipe break are used to limit the size of pipe rupture considered in the design and evaluation of piping systems, as described in subsection 3.6.3, such criteria are not used in the design of the passive core cooling system.

Sufficient water is provided to the reactor vessel following a postulated loss of coolant accident so that the performance criteria for emergency core cooling systems, described in Chapter 15, are satisfied.

The automatic depressurization system valves, provided as part of the reactor coolant system, are designed so that together with the passive core cooling system they:

- Satisfy the small loss of coolant accident performance requirements

- Provide effective core cooling for loss of coolant accidents from when the passive core cooling system is actuated through the long-term cooling mode.

6.3.1.1.4 Safe Shutdown

The functional requirements for the passive core cooling system specify that the plant be brought to a stable condition using the passive residual heat removal heat exchanger for events not involving a loss of coolant. For these events, the passive core cooling system, in conjunction with the passive containment cooling system, has the capability to establish safe shutdown conditions, cooling the reactor coolant system to about 420°F in 36 hours, with or without the reactor coolant pumps operating.

The core makeup tanks automatically provide injection to the reactor coolant system as the temperature decreases and pressurizer level decreases, actuating the core makeup tanks. The passive core cooling system can maintain stable plant conditions for a long time in this mode of operation, depending on the reactor coolant leakage and the availability of ac power sources. For example, with a technical specification leak rate of 10 gpm, stable plant conditions can be maintained for at least 10 hours. With a smaller leak a longer time is available. However in scenarios when ac power sources are unavailable for as long as 24 hours, the automatic depressurization system will automatically actuate.

For loss of coolant accidents and other postulated events where ac power sources are lost, or when the core makeup tank levels reach the automatic depressurization system actuation setpoint, the automatic depressurization system initiates. This results in injection from the accumulators and subsequently from the in-containment refueling water storage tank, once the reactor coolant system is nearly depressurized. For these conditions, the reactor coolant system depressurizes to saturated conditions at about 250°F within 24 hours. The passive core cooling system can maintain this safe shutdown condition indefinitely for the plant.

The basis used to define the passive core cooling system functional requirements are derived from Section 7.4 of the Standard Review Plan. The functional requirements are met over the range of anticipated events and single failure assumptions. The primary function of the passive core cooling system during a safe shutdown using only safety-related equipment is to provide a means for boration, injection, and core cooling. Details of the safe shutdown design bases are presented in subsection 5.4.7 and Section 7.4.

6.3.1.1.5 Containment pH Control

The passive core cooling system is capable of maintaining the desired post-accident pH conditions in the recirculation water after containment floodup. The pH adjustment is capable of maintaining containment pH within a range of 7.0 to 9.5, to enhance radionuclide retention in the containment and to prevent stress corrosion cracking of containment components during long-term containment floodup.

6.3.1.1.6 Reliability Requirements

The passive core cooling system satisfies a variety of reliability requirements, including redundancy (such as for components, power supplies, actuation signals, and instrumentation), equipment testing to confirm operability, procurement of qualified components, and provisions for periodic maintenance. In addition, the system provides protection in a number of areas including:

- Single active and passive component failures
- Spurious failures
- Physical damage from fires, flooding, missiles, pipe whip, and accident loads
- Environmental conditions such as high-temperature steam and containment floodup.

Subsection 6.3.1.2 includes specific nonsafety-related design requirements that help to confirm satisfactory system reliability.

6.3.1.2 Power Generation Design Basis

The passive core cooling system is designed to be sufficiently reliable to support the probabilistic risk analysis goals for core damage frequency and severe release frequency. In assessing the reliability for probabilistic risk analysis purposes, more realistic analysis is used for both the passive core cooling system performance and for plant response.

In the event of a small loss of coolant accident, the passive core cooling system limits the increase in peak clad temperature and core uncovery with design basis assumptions. For pipe ruptures of less than eight-inch nominal diameter size, the passive core cooling system is designed to prevent core uncovery with best estimate assumptions.

The passive residual heat removal heat exchanger and the in-containment refueling water storage tank are designed to delay significant steam release to the containment for at least one hour.

The frequency of automatic depressurization system actuation is limited to a low probability to reduce safety risks and to minimize plant outages. Equipment is located so that it is not flooded or it is designed so that it is not damaged by the flooding. Major plant equipment is designed for multiple occurrences without damage.

The pH control equipment is designed to minimize the potential for and the impact of inadvertent actuation.

The passive core cooling system is capable of supporting the required testing and maintenance, including capabilities to isolate and drain equipment.

6.3.2 System Design

The passive core cooling system is a seismic Category I, safety-related system. It consists of two core makeup tanks, two accumulators, the in-containment refueling water storage tank, the passive residual heat removal heat exchanger, pH adjustment baskets, and associated piping, valves, instrumentation, and other related equipment. The automatic depressurization system valves and

spargers, which are part of the reactor coolant system, also provide important passive core cooling functions.

The passive core cooling system is designed to provide adequate core cooling in the event of design basis events. The redundant onsite safety-related class 1E dc and UPS system provides power such that protection is provided for a loss of ac power sources, coincident with an event, assuming a single failure has occurred.

6.3.2.1 Schematic Piping and Instrumentation Diagrams

Figures 6.3-1 and 6.3-2 show the piping and instrumentation drawings of the passive core cooling system. Simplified flow diagrams are shown in Figures 6.3-3 and 6.3-4. The accident analysis results of events analyzed in Chapter 15 provide a summary of the expected fluid conditions in the passive core cooling system for the various locations shown on the simplified flow diagrams, for the specific plant conditions identified -- safety injection and decay heat removal.

The passive core cooling system is designed to supply the core cooling flow rates to the reactor coolant system specified in Chapter 15 for the accident analyses. The accident analyses flow rates and heat removal rates are calculated by assuming a range of component parameters, including best estimate and conservatively high and low values.

The passive core cooling system design is based on the six major components, listed in subsection 6.3.2.2, that function together in various combinations to support the four passive core cooling system functions:

- Emergency decay heat removal
- Emergency reactor makeup/boration
- Safety injection
- Containment pH control.

6.3.2.1.1 Emergency Core Decay Heat Removal at High Pressure and Temperature Conditions

For events not involving a loss of coolant, the emergency core decay heat removal is provided by the passive core cooling system via the passive residual heat removal heat exchanger. The heat exchanger consists of a bank of C-tubes, connected to a tubesheet and channel head arrangement at the top (inlet) and bottom (outlet). The passive residual heat removal heat exchanger connects to the reactor coolant system through an inlet line from one reactor coolant system hot leg (through a tee from one of the fourth stage automatic depressurization lines) and an outlet line to the associated steam generator cold leg plenum (reactor coolant pump suction).

The inlet line is normally open and connects to the upper passive residual heat removal heat exchanger channel head. The inlet line is connected to the top of the hot leg and is routed continuously upward to the high point near the heat exchanger inlet. The normal water temperature in the inlet line will be hotter than the discharge line.

The outlet line contains normally closed air-operated valves that open on loss of air pressure or on control signal actuation. The alignment of the passive residual heat removal heat exchanger (with

a normally open inlet motor-operated valve and normally closed outlet air-operated valves) maintains the heat exchanger full of reactor coolant at reactor coolant system pressure. The water temperature in the heat exchanger is about the same as the water in the in-containment refueling water storage tank, so that a thermal driving head is established and maintained during plant operation.

The heat exchanger is elevated above the reactor coolant system loops to induce natural circulation flow through the heat exchanger when the reactor coolant pumps are not available. The passive residual heat removal heat exchanger piping arrangement also allows actuation of the heat exchanger with reactor coolant pumps operating. When the reactor coolant pumps are operating, they provide forced flow in the same direction as natural circulation flow through the heat exchanger. If the pumps are operating and subsequently trip, then natural circulation continues to provide the driving head for heat exchanger flow.

The heat exchanger is located in the in-containment refueling water storage tank, which provides the heat sink for the heat exchanger.

Although gas accumulation is not expected, there is a vertical pipe stub on the top of the inlet piping high point that serves as a gas collection chamber. Level detectors indicate when gases have collected in this area. There are provisions to allow the operators to open manual valves to locally vent these gases to the in-containment refueling water storage tank.

The passive residual heat removal heat exchanger, in conjunction with the passive containment cooling system, can provide core cooling for an indefinite period of time. After the in-containment refueling water storage tank water reaches its saturation temperature (in about 2 hours), the process of steaming to the containment initiates.

Condensation occurs on the steel containment vessel, which is cooled by the passive containment cooling system. The condensate is collected in a safety-related gutter arrangement located at the operating deck level which returns the condensate to the in-containment refueling water storage tank. The gutter normally drains to the containment sump, but when the passive residual heat removal heat exchanger actuates, safety-related isolation valves in the gutter drain line shut and the gutter overflow returns directly to the in-containment refueling water storage tank. Recovery of the condensate maintains the passive residual heat removal heat exchanger heat sink for an indefinite period of time.

The passive residual heat removal heat exchanger is used to maintain a safe shutdown condition. It removes decay heat and sensible heat from the reactor coolant system to the in-containment refueling water storage tank, the containment atmosphere, the containment vessel, and finally to the ultimate heat sink–the atmosphere outside of containment. This occurs after in-containment refueling water storage tank saturation is reached and steaming to containment initiates.

6.3.2.1.2 Reactor Coolant System Emergency Makeup and Boration

The core makeup tanks provide reactor coolant system makeup and boration during events not involving loss of coolant when the normal makeup system is unavailable or insufficient. There are two core makeup tanks located inside the containment at an elevation slightly above the reactor

coolant loops. During normal operation, the core makeup tanks are completely full of cold, borated water. The boration capability of these tanks provides adequate core shutdown margin following a steam line break.

The core makeup tanks are connected to the reactor coolant system through a discharge injection line and an inlet pressure balance line connected to a cold leg. The discharge line is blocked by two normally closed, parallel air-operated isolation valves that open on a loss of air pressure or electrical power, or on control signal actuation. The core makeup tank discharge isolation valves are diverse from the passive residual heat removal heat exchanger outlet isolation valves discussed above. They use different globe valve body styles and different air operator types.

The pressure balance line from the cold leg is normally open to maintain the core makeup tanks at reactor coolant system pressure, which prevents water hammer upon initiation of core makeup tank injection.

The cold leg pressure balance line is connected to the top of the cold leg and is routed continuously upward to the high point near the core makeup tank inlet. The normal water temperature in this line will be hotter than the discharge line.

The outlet line from the bottom of each core makeup tank provides an injection path to one of the two direct vessel injection lines, which are connected to the reactor vessel downcomer annulus. Upon receipt of a safeguards actuation signal, the two parallel valves in each discharge line open to align the associated core makeup tank to the reactor coolant system.

There are two operating processes for the core makeup tanks, steam-compensated injection and water recirculation. During steam-compensated injection, steam is supplied to the core makeup tanks to displace the water that is injected into the reactor coolant system. This steam is provided to the core makeup tanks through the cold leg pressure balance line. The cold leg line only has steam flow if the cold legs are voided.

During water recirculation, hot water from the cold leg enters the core makeup tanks, and the cold water in the tank is discharged to the reactor coolant system. This results in reactor coolant system boration and a net increase in reactor coolant system mass.

The operating process for the core makeup tanks depends on conditions in the reactor coolant system, primarily voiding in the cold leg. When the cold leg is full of water, the cold leg pressure balance line remains full of water and the injection occurs via water recirculation. If reactor coolant system inventory decreases sufficiently to cause cold leg voiding, then steam flows through the cold leg balance lines to the core makeup tanks.

Following an event such as steam-line break, the reactor coolant system experiences a decrease in temperature and pressure due to an increase of energy removed by the secondary system as a consequence of the break. The cooldown results in a reduction of the core shutdown margin due to the negative moderator temperature coefficient. There is a potential return to power, assuming the most reactive rod cluster control assembly is stuck in its fully withdrawn position. The actuation of the core makeup tanks following this event provides injection of borated water via water recirculation to mitigate the reactivity transient and provide the required shutdown margin.

In case of a steam generator tube rupture, core makeup tank injection together with the steam generator overfill prevention logic terminates the reactor coolant system leak into the steam generator. This occurs without actuation of the automatic depressurization system and without operator action. In a steam generator tube rupture, the core makeup tanks operate in the water recirculation mode to provide borated water to compensate for reactor coolant system inventory losses and to borate the reactor coolant system. In case of a leak rate of 10 gallons per minute, the passive core cooling system can delay the automatic depressurization system actuation for at least 10 hours while providing makeup water to the reactor coolant system. After the actuation of the automatic depressurization system, the passive core cooling system provides sufficient borated water to compensate for reactor coolant system shrinkage and to provide the reactor coolant system boration.

6.3.2.1.3 Safety Injection During Loss of Coolant Accidents

The passive core cooling system uses four different sources of passive injection during loss of coolant accidents.

- Accumulators provide a very high flow for a limited duration of several minutes.
- The core makeup tanks provide a relatively high flow for a longer duration.
- The in-containment refueling water storage tank provides a lower flow, but for a much longer time.
- The containment is the final long-term source of water. It becomes available following the injection of the other three sources and floodup of containment.

The operation of the core makeup tanks is described in the subsection 6.3.2.1.2. During a loss of coolant accident, they provide injection rates commensurate with the severity of the loss of coolant accident. For a larger loss of coolant accident, and after the automatic depressurization system has been actuated, the cold legs are expected to be voided. In this situation, the core makeup tanks operate at their maximum injection rate with steam entering the core makeup tanks through the cold leg pressure balance lines.

Downstream of the parallel discharge isolation valves, the core makeup tank discharge line contains two check valves, in series, that normally remain open with or without flow in the line. These valves prevent reverse flow through this line, from the accumulator, that would bypass the reactor vessel in the event of a larger loss of coolant accident in the cold leg or the cold leg pressure balance line.

For smaller loss of coolant accidents the core makeup tanks initially operate in the water recirculation mode since the cold legs are water filled. During this water recirculation, the core makeup tanks remain full, but the cold, borated water is purged with hot, less borated cold leg water. The water recirculation provides reactor coolant system makeup and also effectively borates the reactor coolant system. As the accident progresses, when the cold legs void, the core makeup tanks switch to the steam displacement mode which provides higher flow rates.

The two accumulators contain borated water and a compressed nitrogen cover gas to provide rapid injection. They are located inside the reactor containment and the discharge from each tank is connected to one of the direct vessel injection lines. These lines connect to the reactor vessel downcomer. A deflector in the annulus directs the water flow downward to minimize core bypass flow. The water and gas volumes and the discharge line resistance provide several minutes of injection in a large loss of coolant accident.

The in-containment refueling water storage tank is located in the containment at an elevation slightly above the reactor coolant system loop piping. Reactor coolant system injection is possible only after the reactor coolant system has been depressurized by the automatic depressurization system or by a loss of coolant accident. Squib valves in the in-containment refueling water storage tank injection lines open automatically on a 4th stage automatic depressurization signal. Check valves, arranged in series with the squib valves, open when the reactor pressure decreases to below the in-containment refueling water storage tank injection head.

After the accumulators, core makeup tanks, and the in-containment refueling water storage tank inject, the containment is flooded up to a level sufficient to provide recirculation flow through the gravity injection lines back into the reactor coolant system.

The time that it takes until the initiation of containment recirculation flow varies greatly, depending on the specific event. With a break in a direct vessel injection line, the in-containment refueling water storage tank spills out through the break and floods the containment, along with reactor coolant system leakage, and recirculation can occur in several hours. In the event of automatic depressurization without a reactor coolant system break and with condensate return, the in-containment refueling water storage tank level decreases very slowly. Recirculation may not initiate for several days.

Containment recirculation initiates when the recirculation line valves are open and the containment flood-up level is sufficiently high. When the in-containment refueling water storage tank level decreases to a low level, the containment recirculation squib valves automatically open to provide redundant flow paths from the containment to the reactor.

These recirculation flow paths can also provide a suction flow path from the containment to the normal residual heat removal pumps, when they are operating after containment flood up. In addition, the squib valves in the recirculation paths containing normally open motor-operated valves can be manually opened to intentionally drain the in-containment refueling water storage tank to the reactor cavity during severe accidents. This action is modeled in the AP1000 probabilistic risk assessment.

A range of break sizes and locations are analyzed to verify the adequacy of passive core cooling system injection. These events include a no-break case, a complete severance of one (eight-inch) direct vessel injection line case, and other smaller break cases. Successful reactor coolant system depressurization to in-containment refueling water storage tank injection is achieved, as shown in Chapter 15.

In larger loss of coolant accidents, including double ended ruptures in reactor coolant system piping, the passive core cooling system can provide a large flow rate, from the accumulators, to

quickly refill the reactor vessel lower plenum and downcomer. The accumulators provide the required injection flow during the first part of the event including refilling the downcomer and lower plenum and partially reflooding the core. After the accumulators empty, the core makeup tanks complete the reflooding of the core. The subsequent in-containment refueling water storage tank injection and recirculation provide long-term cooling. Both injection lines are available since the injection lines are not the source of a large pipe break.

6.3.2.1.4 Containment pH Control

Control of the pH in the containment sump water post-accident is achieved through the use of pH adjustment baskets containing granulated trisodium phosphate (TSP). The baskets are located below the minimum post-accident floodup level, and chemical addition is initiated passively when the water reaches the baskets. The baskets are placed at least a foot above the floor to reduce the chance that water spills in containment will dissolve the TSP.

The TSP is designed to maintain the pH of the containment sump water in a range from 7.0 to 9.5. This chemistry reduces radiolytic formation of elemental iodine in the containment sump, consequently reducing the aqueous production of organic iodine, and ultimately reducing the airborne iodine in containment and offsite doses.

The chemical addition also helps to reduce the potential for stress corrosion cracking of stainless steel components in a post flood-up condition, where chlorides can leach out of the containment concrete and potentially affect these components during a long-term flood-up event.

6.3.2.1.5 Passive Core Cooling System Actuation

Table 6.3-1 lists the remotely actuated valves used by the various passive core cooling system components. The engineered safeguards features actuation signals used for these valves are described in Section 7.3. Table 6.3-1 shows the normal valve position, the valve position to actuate the associated component, and the failure position of the valve. The failed position represents the position that the valve fails upon loss of electrical power or other motive sources, such as instrument air.

Table 6.3-3 contains the failure mode and effects analysis for the active components of the passive core cooling system.

6.3.2.2 Equipment and Component Descriptions

Table 6.3-2 contains a summary of equipment parameters for major components of the passive core cooling system.

6.3.2.2.1 Core Makeup Tanks

The two core makeup tanks are vertical, cylindrical tanks with hemispherical upper and lower heads. They are made of carbon steel, clad on the internal surfaces with stainless steel. The core makeup tanks are AP1000 Equipment Class A and are designed to meet seismic Category I requirements. They are located inside containment on the 107-foot floor elevation. The core

makeup tanks are located above the direct vessel injection line connections to the reactor vessel, which are located at an elevation near the bottom of the hot leg.

During normal operation the core makeup tanks are completely filled with borated water and are maintained at reactor coolant system pressure by the cold leg pressure balance line. The temperature of the borated water in the core makeup tanks is about the same as the containment ambient temperature since the tanks are not insulated or heated.

The inlet line from the cold leg is sized for loss of coolant accidents, where the cold legs become voided and higher core makeup tank injection flows are required. The discharge line from each core makeup tank contains a flow-tuning orifice that provides a mechanism for the field adjustment of the injection line resistance. The orifice is used to establish the required flow rates assumed in the core makeup tank design. The core makeup tanks provide injection for an extended time after core makeup tank actuation. The duration of injection will be much longer when the core makeup tanks operate in the water recirculation mode as compared to the steam condensation mode.

Connections are provided for remotely adjusting the boron concentration of the borated water in each core makeup tank during normal plant operation, as required. Makeup water for the core makeup tank is provided by the chemical and volume control system. Samples from the core makeup tanks are taken periodically to check boron concentration.

Each core makeup tank has an inlet diffuser which is designed to reduce steam velocities entering the core makeup tank; thereby minimizing potential water hammer and reducing the amount of mixing that occurs during initial core makeup tank operation. The inlet diffuser flow area is $\geq 165\ in^2$.

The core makeup tanks are located inside the containment but outside the secondary shield wall. This facilitates maintenance and inspection.

Core makeup tank level and inlet and outlet line temperatures are monitored by indicators and alarms. The operator can take action as required to meet the technical specification requirements for core makeup tank operability.

6.3.2.2.2 Accumulators

The two accumulators are spherical tanks made of carbon steel and clad on the internal surfaces with stainless steel. The accumulators are AP1000 Equipment Class C and are designed to meet seismic Category I requirements. They are located inside the containment on the floor just below the core makeup tanks.

The accumulators are mostly filled with borated water and pressurized with nitrogen gas. The temperature of the borated water in the accumulators is about the same as the containment ambient temperature since the tanks are not insulated or heated. Each accumulator is connected to one of the direct vessel injection lines. During normal operation, the accumulator is isolated from the reactor coolant system by two check valves in series. When the reactor coolant system pressure falls below the accumulator pressure, the check valves open and borated water is forced into the

reactor coolant system by the gas pressure. Mechanical operation of the check valves is the only action required to open the injection path from the accumulators to the core.

The accumulators are designed to deliver a high flow of borated water to the reactor vessel in the event of a large loss of coolant accident. This large flow rate is used to quickly establish core cooling following the large loss of reactor coolant system inventory.

The injection line from each accumulator contains a flow-tuning orifice that provides a mechanism for the field adjustment of the injection line resistance. The orifice is used to establish the required flow rates assumed in the accumulator design. The accumulator provides injection for several minutes after reactor coolant system pressure drops below the static accumulator pressure.

Connections are provided for remotely adjusting the level and boron concentration of the borated water in each accumulator during normal plant operation, as required. Accumulator water level may be adjusted either by draining or by pumping borated water from the chemical and volume control system to the accumulator. Samples from the accumulators are taken periodically to check the boron concentration.

Accumulator pressure is provided by a supply of nitrogen gas and can be adjusted as required during normal plant operation. However, the accumulators are normally isolated from the nitrogen supply. Gas relief valves on the accumulators protect them from overpressurization. The system also includes the capability to remotely vent gas from the accumulator, if required.

The accumulators are located inside the containment and outside the secondary shield wall. This facilitates maintenance and inspection.

Accumulator level and pressure are monitored by indication and alarms. The operator can take action, as required, to meet the technical specification requirements for accumulator operability.

6.3.2.2.3 In-Containment Refueling Water Storage Tank

The in-containment refueling water storage tank is a large, stainless-steel lined tank located underneath the operating deck inside the containment. The in-containment refueling water storage tank is AP1000 Equipment Class C and is designed to meet seismic Category I requirements. The tank is constructed as an integral part of the containment internal structures, and is isolated from the steel containment vessel. See subsection 3.8.3 for additional information.

The bottom of the in-containment refueling water storage tank is above the reactor coolant system loop elevation so that the borated refueling water can drain by gravity into the reactor coolant system after it is sufficiently depressurized. The in-containment refueling water storage tank is connected to the reactor coolant system through both direct vessel injection lines. The in-containment refueling water storage tank contains borated water, at the existing temperature and pressure in containment.

Vents are installed in the roof of the in-containment refueling water storage tank. These vents are normally closed in order to contain water vapor and radioactive gases within the tank during normal operation and to prevent debris from entering the tank from the containment operating

deck. The vents open with a slight pressurization of the in-containment refueling water storage tank. These vents provide a path to vent steam released by the spargers or generated by the passive residual heat removal heat exchanger, into the containment atmosphere. Other vents also open on small pressure differentials, such as during a loss of coolant accident, to prevent damage to the in-containment refueling water storage tank. Overflows are provided from the in-containment refueling water storage tank to the refueling cavity to accommodate volume and mass increases during passive residual heat removal heat exchanger or automatic depressurization system operation, while minimizing the floodup of the containment.

The IRWST is stainless steel lined and does not contain material either in the tank or the recirculation path that could plug the outlet screens.

The in-containment refueling water storage tank contains one passive residual heat removal heat exchanger and two depressurization spargers. The top of the passive residual heat removal heat exchanger tubes are located underwater and extend down into the in-containment refueling water storage tank. The spargers are also submerged in the in-containment refueling water storage tank, with the spargers midarms located below the normal water level.

The in-containment refueling water storage tank is sized to provide the flooding of the refueling cavity for normal refueling, the post-loss of coolant accident flooding of the containment for reactor coolant system long-term cooling mode, and to support the passive residual heat removal heat exchanger operation. Flow out of the in-containment refueling water storage tank during the injection mode includes conservative allowances for spill flow during a direct vessel injection line break.

The in-containment refueling water storage tank can provide sufficient injection until the containment sump floods up high enough to initiate recirculation flow. The injection duration varies greatly, depending upon the specific event. A direct vessel injection line break more rapidly drains the in-containment refueling water storage tank and speeds containment floodup.

The containment floodup volume for a LOCA in PXS room B is less than 73,500 ft^3 (excluding the in-containment refueling water storage tank) below a containment elevation of 108 feet.

Connections to the in-containment refueling water storage tank provide for transfer to and from the reactor coolant system/refueling cavity via the normal residual heat removal system, purification and sampling via the spent fuel pit cooling system, and remotely adjusting boron concentration to the chemical and volume control system. Also, the normal residual heat removal system can provide cooling of the in-containment refueling water storage.

In-containment refueling water storage tank level and temperature are monitored by indicators and alarms. The operator can take action, as required, to meet the technical specification requirements for in-containment refueling water storage tank operability.

6.3.2.2.4 pH Adjustment Baskets

The passive core cooling system utilizes pH adjustment baskets for control of the pH level in the containment sump. The baskets are made of stainless steel with a mesh front that readily permits

contact with water. The baskets are designated AP1000 Equipment Class C, and are designed to meet seismic Category I requirements.

The total weight of TSP contained in the baskets is at least 27,540 pounds. The TSP, in granular form, is provided to raise the pH of the borated water in the containment following an accident to at least 7.0. After extended plant operation, the granular TSP may cake into a solid form as it absorbs moisture. Assuming that the TSP has caked, the dissolution time of the TSP is approximately 3 hours. Good mixing with the sump water is expected due to both basket construction and because the baskets are placed in locations conducive to recirculation flows post-accident. The baskets are designed for ease of replacement of the TSP.

6.3.2.2.5 Passive Residual Heat Removal Heat Exchanger

The passive residual heat removal exchanger consists of inlet and outlet channel heads connected together by vertical C-shaped tubes. The tubes are supported inside the in-containment refueling water storage tank. The top of the tubes is several feet below the in-containment refueling water storage tank water surface. The component data for the passive residual heat removal heat exchanger is shown in Table 6.3-2. The passive residual heat removal heat exchanger is AP1000 Equipment Class A and is designed to meet seismic Category I requirements.

The heat exchanger inlet piping connects to an inlet channel head located near the outside top of the tank. The inlet channel head and tubesheet are attached to the tank wall via an extension flange. The heat exchanger is supported by a frame which is attached to the IRWST floor and ceiling. The heat exchanger supports are designed to ASME Code, Section III, subsection NF. The extended flange is designed to accommodate thermal expansion. Figure 6.3-5 illustrates the relationship between these parts and the boundaries of design code jurisdiction. The heat exchanger outlet piping is connected to the outlet channel head, which is vertically below the inlet channel head, near the tank bottom. The outlet channel head has an identical structural configuration to the inlet channel head. Both channel head tubesheets are similar to the steam generator tubesheets and they have manways for inspection and maintenance access.

The passive residual heat removal heat exchanger is designed to remove sufficient heat so that its operation, in conjunction with available inventory in the steam generators, provide reactor coolant system cooling and prevents water relief through the pressurizer safety valves during loss of main feedwater or main feedline break events.

Passive residual heat removal heat exchanger flow and inlet and outlet line temperatures are monitored by indicators and alarms. The operator can take action, as required, to meet the technical specification requirements or follow emergency operating procedures for control of the passive residual heat removal heat exchanger operation.

6.3.2.2.6 Depressurization Spargers

Two reactor coolant depressurization spargers are provided. Each one is connected to an automatic depressurization system discharge header (shared by three automatic depressurization system stages) and submerged in the in-containment refueling water storage tank. Each sparger has four branch arms inclined downward. The connection of the sparger branch arms to the sparger hub are

submerged below the in-containment refueling water storage tank overflow level by ≤11.5 feet. The component data for the spargers is shown in Table 6.3-2. The spargers are AP1000 Equipment Class C and are designed to meet seismic Category I requirements.

The spargers perform a nonsafety-related function -- minimizing plant cleanup and recovery actions following automatic depressurization. They are designed to distribute steam into the in-containment refueling water storage tank, thereby promoting more effective steam condensation.

The first three stages of automatic depressurization system valves discharge through the spargers and are designed to pass sufficient depressurization venting flow, with an acceptable pressure drop, to support the depressurization system performance requirements. The installation of the spargers prevents undesirable and/or excessive dynamic loads on the in-containment refueling water storage tank and other structures.

Each sparger is sized to discharge at a flow rate that supports automatic depressurization system performance, which in turn, allows adequate passive core cooling system injection.

6.3.2.2.7 IRWST and Containment Recirculation Screens

The passive core cooling systems has two different sets of screens that are used following a LOCA; IRWST screens and containment recirculation screens. These screens prevent debris from entering the reactor and blocking core cooling passages during a LOCA. These screens are designed to comply with applicable licensing regulations including:

- GDC 35 of 10 CFR 50 Appendix A
- Regulatory Guide 1.82
- NUREG-0897

The operation of the passive core cooling system following a LOCA is described in subsection 6.3.2.1.3. Proper screen design, plant layout, and other factors prevent clogging of these screens by debris during accident operations.

6.3.2.2.7.1 General Screen Design Criteria

1. Screens are designed to Regulatory Guide 1.82, including:

   - Redundant screens are provided for each function

   - Separate locations are used for redundant screens

   - Screens are located well below containment floodup level. Each screen has a coarse and a fine screen, and a debris curb

   - Floors slope away from screens (not required for AP1000)

   - Drains do not impinge on screens

- Screens can withstand accident loads and credible missiles

- Screens have conservative flow areas to account for plugging. Operation of the non-safety-related normal residual heat removal pumps with suction from the IRWST and the containment recirculation lines is considered in sizing screens.

- System and screen performance are evaluated

- Screens have solid top cover. Containment recirculation screens have protective plates that are located no more than 1 foot above the top of the screens and extend at least 10 feet in front and 7 feet to the side of the screens. The plate dimensions are relative to the portion of the screens where water flows through the trash rack.

- Screens are seismically qualified

- Screen openings are sized to prevent blockage of core cooling

- Screens are designed for adequate pump performance. AP1000 has no safety-related pumps.

- Corrosion resistant materials are used for screens

- Access openings in screens are provided for screen inspection

- Screens are inspected each refueling

2. Low screen approach velocities limit the transport of heavy debris even with operation of normal residual heat removal pumps.

3. Metal reflective insulation is used on ASME class 1 lines because they are subject to loss-of-coolant accidents. Metal reflective insulation is also used on the reactor vessel, the reactor coolant pumps, the steam generators, and on the pressurizer because they have relatively large insulation surface areas and they are located close to large ASME class 1 lines. As a result, they are subject to jet impingement during loss-of-coolant accidents. A suitable equivalent insulation to metal reflective may be used. A suitable equivalent insulation is one that is enclosed such that LOCA jet impingement does not damage the insulation and generate debris or one that may be damaged by LOCA jet impingement as long as the resulting insulation debris are not transported to the containment recirculation screens.

   In order to provide additional margin, metal reflective insulation is used on lines that are subject to jet impingement during loss-of-coolant accidents that are not otherwise shielded from the blowdown jet. As a result, fibrous debris is not generated by loss-of-coolant accidents. Insulation located in a spherical region within a distance equal to 20 inside diameters of the LOCA pipe break is assumed to be affected by the LOCA when there are intervening components, supports, structures, or other objects. In the absence of intervening components, supports, structures, or other objects insulation in a cylindrical area extending out a distance equal to 45 inside diameters from the break along an axis that is a continuation

of the pipe axis and up to 5 inside diameters in the radial direction from the axis is assumed to be affected by the LOCA.

4. Coatings are not used on surfaces located close to the containment recirculation screens. The surfaces considered close to the screens are defined in subsection 6.3.2.2.7.3. Refer to subsection 6.1.2.1.6. These surfaces are constructed of materials that do not require coatings.

5. The IRWST is enclosed which limits debris egress to the IRWST screens.

6. Containment recirculation screens are located above lowest levels of containment.

7. Long settling times are provided before initiation of containment recirculation.

8. Air ingestion by safety-related pumps is not an issue in the AP1000 because there are no safety-related pumps. The normal residual heat removal system pumps are evaluated to show that they can operate with minimum water levels in the IRWST and in the containment.

9. A COL commitment for cleanliness program to limit debris in containment is provided.

10. Other potential sources of fibrous material, such as ventilation filters or fiber producing fire barriers, are not located in jet impingement damage zones or in the flood-up region.

6.3.2.2.7.2 IRWST Screens

The IRWST screens are located inside the IRWST at the bottom of the tank. Figure 6.3-6 shows a plan view and Figure 6.3-7 shows a section view of these screens. Two separate screens are provided in the IRWST, one at either end of the tank. The IRWST is closed off from the containment; its vents and overflows are normally closed by louvers. The potential for introducing debris inadvertently during plant operations is limited. A COL cleanliness program (refer to subsection 6.3.8.1) controls foreign debris from being introduced into the tank during maintenance and inspection operations. The Technical Specifications require visual inspections of the screens during every refueling outage.

The IRWST design eliminates sources of debris from inside the tank. Insulation is not used in the tank. Air filters are not used in the IRWST vents or overflows. Wetted surfaces in the IRWST are corrosion resistant such as stainless steel or nickel alloys; the use of these materials prevents the formation of significant amounts of corrosion products. In addition, the water is required to be clean because it is used to fill the refueling cavity for refueling; filtering and demineralizing by the spent fuel pit cooling system is provided during and after refueling.

During a LOCA, steam vented from the reactor coolant system condenses on the containment shell, drains down the shell to the operating deck elevation and is collected in a gutter. It is very unlikely that debris generated by a LOCA can reach the gutter because of its location. The gutter is covered with a trash rack which prevents larger debris from clogging the gutter or entering the IRWST through the two 4 inch drain pipes. The inorganic zinc coating applied to the inside surface of the containment shell is one potential source of debris that may enter the gutter and the IRWST. As described in subsection 6.1.2.1.5, failure of this coating produces a heavy powder

which if it enters the IRWST through the gutter will settle out on the bottom of the IRWST because of its high specific gravity. Settling is enhanced in the IRWST by low velocities in the tank and long tank drain down times.

The design of the IRWST screens reduces the chance of debris reaching the screens. The screens are oriented vertically such that debris that settles out of the water does not fall on the screens. A debris curb located at the base of the IRWST screens prevents high density debris from being swept along the floor by water flow to the IRWST screens. The IRWST screens are made up of a trash rack and a fine screen. The trash rack prevents larger debris from reaching the finer screen. The fine screen prevents debris larger than 0.125" from being injected into the reactor coolant system and blocking fuel cooling passages. The fine screen is a folded type that has more surface area than the trash rack to accommodate debris that could pass through the trash rack and be trapped on the fine screen.

The screen flow area is conservatively designed considering the operation of the nonsafety-related normal residual heat removal system pumps which produce a higher flow than the safety-related gravity driven IRWST injection/recirculation flows. As a result, when the normal residual heat removal system pumps are not operating there is a large margin to screen clogging.

6.3.2.2.7.3 Containment Recirculation Screens

The containment recirculation screens are oriented vertically along walls above the loop compartment floor (elevation 83 feet). Figure 6.3-8 shows a plan view and Figure 6.3-9 shows a section view of these screens. Two separate screens are provided as shown in Figure 6.3-3. The loop compartment floor elevation is significantly above (11.5 feet) the lowest level in the containment, the reactor vessel cavity. The bottom of the recirculation screen is two foot above the floor, providing a curb function.

During a LOCA, the reactor coolant system blowdown will tend to carry debris created by the accident (pipe whip/jets) into the cavity under the reactor vessel which is located away from and below the containment recirculation screens. As the accumulators, core makeup tanks and IRWST inject, the containment water level will slowly rise above the 108 foot elevation. The containment recirculation line opens when the water level in the IRWST drops to a low level setpoint a few feet above the final containment floodup level. When the recirculation lines initially open, the water level in the IRWST is higher than the containment water level and water flows from the IRWST backwards through the containment recirculation screen. This back flow tends to flush debris located close to the recirculation screens away from the screens. A cross connect pipe line interconnects the two recirculation screens so that both recirculation screens will operate, even in the case of a LOCA of a DVI line in a PXS valve room. Such a LOCA can flood the recirculation valves located in one of the PXS rooms before they are actuated, and the failure of these valves is assumed since they are not qualified to operate in such conditions. The recirculation valves in the other PXS valve room are unaffected.

The water level in the containment when recirculation begins is well above (~ 10 feet) the top of the recirculation screens. During the long containment floodup time, floating debris does not move toward the screens and heavy materials settle to the floors of the loop compartments or the reactor

vessel cavity. During recirculation operation the containment water level will not change significantly nor will it drop below the top of the screens.

The amount of debris that may exist following an accident is limited. Reflective insulation is used to preclude fibrous debris that can be generated by a loss of coolant accident and be postulated to reach the screens during recirculation. The nonsafety-related coatings used in the containment are designed to withstand the post accident environment. The containment recirculation screens are protected by plates located above them. These plates prevent debris from the failure of nonsafety-related coatings from getting into the water close to the screens such that the recirculation flow can cause the debris to be swept to the screens before it settles to the floor. Stainless steel is used on the underside of these plates and on surfaces located below the plates, above the bottom of the screens, 10 feet in front and 7 feet to the side of the screens to prevent coating debris from reaching the screens.

A COL cleanliness program (refer to subsection 6.3.8.1) controls foreign debris introduced into the containment during maintenance and inspection operations. The Technical Specifications require visual inspections of the screens during every refueling outage.

The design of the containment recirculation screens reduces the chance of debris reaching the screens. The screens are orientated vertically such that debris settling out of the water will not fall on the screens. The protective plates described above provide additional protection to the screens from debris. The bottom of the screens are located 2 feet above the floor, instead of using a debris curb, to prevent high density debris from being swept along the floor by water flow to the containment recirculation screens. The containment recirculation screens are made up of a trash rack and a fine screen. The trash rack prevents larger debris from reaching the finer screen. The fine screen prevents debris larger than 0.125" from being injected into the reactor coolant system and blocking fuel cooling passages. The fine screen prevents debris larger than 0.125" from being injected into the reactor coolant system and blocking fuel cooling passages. The fine screen is a folded type that has more surface area than the trash rack to accommodate debris that could pass through the trash rack and be trapped on the fine screen.

The screen flow area is conservatively designed, considering the operation of the normal residual heat removal system pumps, which produce a higher flow than the gravity driven IRWST injection/recirculation flows. As a result, when the normal residual heat removal system pumps are not operating there is even more margin in screen clogging.

6.3.2.2.8 Valves

Design features used to minimize leakage for valves in the passive core cooling system include:

- Packless valves are used for manual isolation valves that are 2 inches or smaller.

- Valves which are normally open, except check valves and those which perform control function, are provided with back seats to limit stem leakage.

6.3.2.2.8.1 Manual Globe, Gate, and Check Valves

Gate valves have backseats and external screw and yoke assemblies.

Globe valves, both “T” and “Y” styles, are full-ported with external screw and yoke construction.

Check valves are spring-loaded lift piston types for sizes 2 inches and smaller, and swing-type for sizes 2.5 inches and larger. Stainless steel check valves have no penetration welds other than the inlet, outlet, and bonnet. The check valve hinge is serviced through the bonnet.

The gasket of the stainless steel manual globe and gate valves is similar to those described in subsection 6.3.2.2.8.3 for motor-operated valves.

6.3.2.2.8.2 Manual Valves

Manual valves are generally used as maintenance isolation valves. When used for this function they are under administrative control. They are located so that no single valve can isolate redundant passive core cooling system equipment or they are provided with alarms in the main control room to indicate mispositioning.

To help preclude the possibility of passive core cooling system degradation due to valve mispositioning, line connections such as vent and drain lines, test connections, pressure points, flow element test points, flush connections, local sample points, and bypass lines are provided with double isolation or sealed barriers. The isolation is provided by one of the following methods:

- Two valves in series
- A single valve with a screwed cap or blind flange
- A single locked-closed valve
- A blind flange.

6.3.2.2.8.3 Motor-Operated Valves

The motor operators for gate valves are conservatively sized, considering the frictional component of the hydraulic unbalance on the valve disc, the disc face friction, and the packing box friction. For motor-operated valves, the valve disc is guided throughout the full disc travel to prevent chattering and to provide ease of gate movement. The seating surfaces are hard-faced to prevent galling and to reduce wear.

Where a gasket is employed for the body to bonnet joint, it is either a fully trapped, controlled compression, spiral wound asbestos (or a qualified asbestos substitute) gasket with provisions for seal welding or it is of the pressure seal design with provisions for seal welding.

The motor operator incorporates a hammer-blow feature that allows the motor to impact the disc away from the back seat upon closing. This hammer-blow feature impacts the discs and allows the motor to attain its operational speed prior to impact.

6.3.2.2.8.4 Motor-Operated Valve Controls

Remotely operated valves which do not receive a safeguards actuation signal, have their positions indicated on the main control board. When one of these valves is not in the ready position for injection during plant operation, this condition is indicated and alarmed in the main control room.

Spurious movement of a motor-operated valve due to an electrical fault in the motor actuation circuitry, coincident with loss of coolant accident, has been analyzed (Reference 1) and found to be an acceptably low probability event. In addition, power lockout in accordance with Branch Technical Position ICSB-18 is provided for those valves whose spurious movement could result in degraded passive core cooling system performance.

Table 6.3-1 provides a list of the remotely operated isolation valves in the passive core cooling system. These valves have various interlocks, automatic features, and position indication. Some valves have their control power locked out during normal plant operation. Periodic visual inspection and operability testing of the motor-operated valves in the passive core cooling system confirm valve operability. In addition, the location of the motor-operated valves within the containment, which are identified in Table 6.3-1, has been examined to identify remotely operated valves which may be submerged following a postulated loss of coolant accident.

See Section 3.4 for additional information on containment flooding effects.

6.3.2.2.8.5 Automatic Depressurization Valves

The automatic depressurization system consists of four different stages of valves. The first three stages each have two lines and each line has two valves in series; both normally closed. The fourth stage has four lines with each line having two valves in series; one normally open and one normally closed. The four stages, therefore, include a total of 20 valves. The four valve stages open sequentially.

The first stage, second-stage and third-stage valves have dc motor operators. The stage 1/2/3 control valves are normally closed globe valves; the isolation valves are normally closed gate valves. The fourth-stage valves are interlocked so that they can not open until reactor coolant system pressure has been substantially reduced. The fourth stage control valves are squib valves. There is a normally open motor-operated gate valve in series with each squib valve.

The first three stages have a common inlet header connected to the top of the pressurizer. The outlet of the first to third stages then combine to a common discharge line to one of the spargers in the in-containment refueling water storage tank. There is a second identical group of first- to third-stage valves with its own inlet and outlet line and sparger.

The fourth-stage valves connect directly to the top of the reactor coolant hot leg and vent directly to the steam generator compartment. There are also two groups of fourth stage valves, with one group in each steam generator compartment.

The automatic depressurization valves are designed to automatically open when actuated and to remain open for the duration of an automatic depressurization event. Valve stages 1 and 4 actuate

at discrete core makeup tank levels, as either tank's level decreases during injection or from spilling out a broken injection line. Valve stages 2 and 3 actuate based upon a timed delay after actuation of the preceding stage. This opening sequence provides a controlled depressurization of the reactor coolant system. The valve opening sequence prevents simultaneous opening of more than one stage, to allow the valves to sequentially open. The valve actuation logic is based on two-of-four level detectors, in either core makeup tank for automatic depressurization system stages 1 and 4.

The stage 1/2/3 automatic depressurization control valves are designed to open relatively slowly. During the actuation of each stage, the isolation valve is sequenced open before the control valve. Therefore, there is some time delay between stage actuation and control valve actuation.

The operators can manually open the first-stage valves to a partially open position to perform a controlled depressurization of the reactor coolant system. Additional information on the automatic depressurization valves is provided in subsection 5.4.6.

6.3.2.2.8.6 Low Differential Pressure Opening Check Valves

Several applications in the passive core cooling system gravity injection piping use check valves that open with low differential pressures. These check valves are installed in the following locations:

- The gravity injection line flow paths from the in-containment refueling water storage tank
- The containment recirculation lines that connect to the gravity injection lines

The check valves selected for these applications incorporate a simple swing-check design with a stainless steel body and hardened valve seats. The passive core cooling system check valves are safety-related, designed with their operating parts contained within the body, and with a low pressure drop across each valve. The valve internals are exposed to low temperature reactor coolant or borated refueling water.

During normal plant operation, these check valves are closed, with essentially no differential pressure across them. Confidence in the check valve operability is provided by operation at no differential pressure clean/cold fluid environment, the simple valve design, and the specified seat materials.

The check valves normally remain closed, except for testing or when called upon to open following an event to initiate passive core cooling system operation. The valves are not subject to the degradation from flow operation or impact loads caused by sudden flow reversal and seating, and they do not experience significant wear of the moving parts.

These check valves are periodically tested during shutdown conditions to demonstrate valve operation. These check valves are equipped with nonintrusive position sensors to indicate when the valves are open or closed.

In current plants, there are many applications of simple swing-check valves that have similar operating conditions to those in the passive core cooling system. The extensive operational history

and experience derived from similar check valves used in the safety injection systems of current pressurized water reactors indicate that the design is reliable. Check valve failure to open and common mode failures have not been significant problems.

6.3.2.2.8.7 Accumulator Check Valves

The accumulator check valve design is similar to the accumulator check valves in current pressurized water reactor applications. It is also similar to the low differential pressure opening check valve design described in subsection 6.3.2.2.8.6. The accumulator check valves are diverse from the core makeup tank valves because they use different check valve types.

During normal operation, the check valves are in the closed position with a nominal differential pressure across the disc of about 1550 psid. The valves remain in this position, except for testing or when called upon to open following an event. They are not subject to the degradation from flow operation or impact loads caused by sudden flow reversal and seating. They do not experience significant wear of the moving parts and they are expected to function with minimal backleakage.

The accumulators can accept some inleakage from the reactor coolant system without affecting availability. Continuous inleakage requires that the accumulator water volume and boron concentration be adjusted periodically to meet technical specification requirements.

The AP1000 accumulator check valves are periodically tested during shutdown conditions to demonstrate their operation.

6.3.2.2.8.8 Relief Valves

Relief valves are installed for passive core cooling system accumulators to protect the tanks from overpressure.

The passive core cooling system piping is reviewed to identify those lengths of piping that are isolated by normally closed valves and that do not have pressure relief protection in the piping section between the valves.

These piping sections include:

- Portions of in-containment passive core cooling system test lines that are not passive core cooling system accident mitigation flow paths and are not needed to achieve safe shutdown
- Piping vents, drains, and test connections that typically have two closed valves or one closed valve and a blind flange
- Check valve test lines with sections isolated by two normally closed valves.

The piping vents, drains, test connections, and check valve lines have design pressure/temperature conditions compatible with the process piping to which they connect. Valve leakage does not overpressurize the isolated piping sections and pressure relief provisions are not required.

6.3.2.2.8.9 Explosively Opening (Squib)Valves

Squib valves are used in several passive core cooling system lines in order to provide the following:

- Zero leakage during normal operation
- Reliable opening during an accident
- Reduced maintenance and associated personnel radiation exposure

Squib valves are used to isolate the incontainment refueling water storage tank injection lines and the containment recirculation lines. In these applications, the squib valves are not expected to be opened during normal operation and anticipated transients. In addition, after they are opened it is not necessary that they re-close.

In the incontainment refueling water storage tank injection lines, the squib valves are in series with normally closed check valves. In the containment recirculation lines, the squib valves are in series with normally closed check valves in two lines and with normally open motor operated valves in the other two lines. As a result, inadvertent opening of these squib valves will not result in loss of reactor coolant or in draining of the incontainment refueling water storage tank.

The type of squib valve used in these applications provides zero leakage in both directions. It also allows flow in both directions. A valve open position sensor is provided for these valves. The IRWST injection squib valves and the containment recirculation squib valves in series with check valves are diverse from the other containment recirculation squib valves. They are designed to different design pressures.

Squib valves are also used to isolate the fourth stage automatic depressurization system lines. These squib valves are in series with normally open motor operated gate valves. Actuation of these squib valves requires signals from two separate protection logic cabinets. This helps to prevent spurious opening of these squib valves. The type of squib valve used in this application provides zero leakage of reactor coolant out of the reactor coolant system. The reactor coolant pressure acts to open the valve. A valve open position sensor is provided for these valves.

6.3.2.3 Applicable Codes and Classifications

Sections 5.2 and 3.2 list the equipment ASME Code and seismic classification for the passive core cooling system. Most of the piping and components of the passive core cooling system within containment are AP1000 Equipment Class A, B, or C and are designed to meet seismic Category I requirements. Equipment Class C components and piping, that provide an emergency core cooling function, have augmented weld inspection requirements (see subsection 3.2.2.5). Some system piping and components that do not perform safety-related functions are nonsafety-related.

The requirements for the control, actuation, and Class 1E devices are presented in Chapters 7 and 8.

6.3.2.4 Material Specifications and Compatibility

Materials used for engineered safety feature components are given in Section 6.1. Materials for passive core cooling system components are selected to the meet the applicable material requirements of the codes in Section 5.2, as well as the following additional requirements:

- Parts of components in contact with borated water are fabricated of, or clad with, austenitic stainless steel or an equivalent corrosion-resistant material.
- Internal parts of components in contact with containment emergency sump solution during recirculation are fabricated of austenitic stainless steel or an equivalent corrosion resistant material.
- Valve seating surfaces are hard-faced to prevent failure and to reduce wear.
- Valve stem materials are selected for their corrosion resistance, high-tensile properties, and their resistance to surface scoring by the packing.

Section 6.1 summarizes the materials used for passive core cooling system components.

6.3.2.5 System Reliability

The reliability of the passive core cooling system is considered including periodic testing of the components during plant operation. The passive core cooling system is a redundant, safety-related system. The system is designed to withstand credible single active or passive failures.

The initiating signals for the passive core cooling system are derived from independent sources as measured from process parameters (pressurizer low pressure) or environmental (containment high pressure) variables. Redundant, as well as functionally independent variables, are measured to initiate passive core cooling system operation.

Redundant passive core cooling system components are physically separated and protected so that a single event cannot initiate a common failure.

Power sources for the passive core cooling system are divided into four independent divisions that are supplied from the Class 1E dc and UPS system. Sufficient battery capacity is maintained to provide required power to the emergency loads when onsite and offsite ac power sources are not available. Section 8.3 provides additional information.

The preoperational testing program confirms that the systems, as designed and constructed meet the functional design requirements. Section 14.2 provides additional information. The passive core cooling system is designed with the capability for on-line testing of its active components so the availability and operation status can be readily determined. Testing of passive components such as check valves, tanks, heat exchanger, and flow paths can be conducted during shutdown conditions. In addition, the integrity of the passive core cooling system is verified through examination of critical components during the routine in-service inspection. Section 3.9.6 provides additional information.

The reliability assurance program described in Section 16.2, extends to the procurement of passive core cooling system components. The procurement quality assurance program is described in Chapter 17.

The passive core cooling system is a redundant, safety-related system. During the long-term cooling period following a loss of coolant accident, once the passive core cooling system equipment has actuated, there is no long-term maintenance required. Components actuate to the safeguards actuation alignment and do not need subsequent position changes for long-term operation.

For long-term cooling, the reactor coolant system is depressurized to containment ambient pressure following a loss of coolant accident. During this period, the heat generated in the reactor core is the residual decay heat and the passive core cooling system provides the required decay heat removal.

Proper initial filling and venting of the passive core cooling system prevents water hammer from occurring in the passive core cooling system lines. In addition, the head of water provided by the various tanks keeps system lines full. The arrangement of the core makeup tank pressure equalization line design also reduces the potential for water hammer. High-point vents in the passive core cooling system lines are provided as a means for venting of lines. Fill and venting procedures for the passive core cooling system provide for the removal of air from the system.

The existence of high-point vents and the positive head of water provide means by which the operator can confirm water-solid passive core cooling system lines, where required.

6.3.2.5.1 Response to Active Failure

Treatment of active failures is described in Section 15.0.12.

An active failure is the failure of a powered component, a component of the electrical supply system, or instrumentation and control equipment to act on command to perform its function. One example is the failure of a motor-operated valve to move to its intended safeguards actuation position.

One change in the definition of active failures has been incorporated into the passive core cooling system design. The system has been specifically designed to treat check valve failures to reposition as active failures. More specifically, it is assumed that normally closed check valves may fail to open and normally open check valves may fail to close. Check valves that remain in the same position before and after an event are not considered active failures.

There are two exceptions to this treatment of check valve failures in the passive core cooling system. One exception is made for the accumulator check valves, which is consistent with the treatment of these specific check valves in currently licensed plant designs. The other exception is made for the core makeup tank check valves failure to re-open after they have closed during an accident. The valves are normally open, biased-opened check valves. This exception is based on the low probability of these check valves not re-opening within a few minutes after they have cycled closed during accumulator operation.

The failure mode and effects analysis provided in Table 6.3-3 provides a summary of the passive core cooling system response to single failure of the various active components required for system safeguards functions.

The following passive core cooling system motor-operated valves are not included in this analysis:

- Both accumulator discharge line motor-operated valves
- Both in-containment refueling water storage tank gravity injection line motor-operated valves.
- Both containment recirculation line motor-operated valves.
- Both core makeup tank inlet line motor-operated valves
- The passive residual heat removal heat exchanger inlet line motor-operated valve

These valves are normally in the required position for actuation of the associated component, they have redundant position indications and alarms, and they also receive confirmatory open actuation signals. The accumulator, incontainment refueling water storage tank and passive residual heat removal heat exchanger valves have their power removed and locked out. The core makeup tank and the containment recirculation line have redundant series controllers. Therefore, these valves are not considered in the failure modes and effects analysis.

The analysis illustrates that the passive core cooling system can sustain an active failure in either the short-term or long-term and meet the required level of performance for core cooling. The short-term operation of the active components of the passive core cooling system following a steam line rupture or a steam generator tube rupture is similar to that following a loss of coolant accident. The same analysis is applicable and the passive core cooling system can sustain the failure of a single active component and meet the level of performance for the addition of shutdown reactivity.

Portions of the passive core cooling system are also relied upon to provide boration and makeup during a safety-related shutdown. The passive core cooling system can sustain an active failure and perform the required functions necessary to establish safe shutdown conditions. Safe shutdown operation of the passive core cooling system is described in Section 7.4.

6.3.2.5.2 Response to Passive Failure

Treatment of passive failures is described in subsection 15.0.12.

A passive failure is the structural failure of a static component which limits the component's effectiveness in carrying out its design function. Examples include cracking of pipes, sprung flanges, or valve packing leaks. The passive core cooling system can sustain a single passive failure during the long-term phase and still retain an intact flow path to the core to supply sufficient flow to keep the core covered and to remove decay heat.

Since the passive core cooling system equipment is inside the containment, offsite dose caused by passive failures is not a concern. Also, with actuation of the automatic depressurization system, the reactor coolant system pressure is very close to containment pressure. Therefore, it is not necessary to isolate or realign the passive core cooling system following a passive failure.

The passive core cooling system flow paths are separated into redundant lines, either of which can provide minimum core cooling functions and return spilled water from the floor of the containment back to the reactor coolant system. For the long-term passive core cooling system function, adequate core cooling capacity exists with one of the two redundant flow paths.

6.3.2.5.3 Lag Times

Lag times for initiation and operation of the passive core cooling system are controlled by repositioning of valves. Some valves are normally in the position required for safety-related system function and therefore, their valve operation times are not considered. For those valves that reposition to initiate safety-related system functions, the valve repositioning times are less than the times assumed in the accident analyses. These lag times refer to the time after initiation of the safeguards actuation signal.

It is acceptable for the core makeup tank injection to be delayed several minutes following actuation due to high initial steam condensation rates in the tank.

6.3.2.5.4 Potential Boron Precipitation

Boron precipitation in the reactor vessel is prevented by sufficient flow of passive core cooling system water through the core to limit the increase in boron concentration of the water remaining in the reactor vessel. Water along with steam leaves the core and exits the RCS through the fourth stage ADS lines. These valves connect to the hot leg and open in about 20 minutes after a loss of coolant accident or an automatic depressurization system actuation.

6.3.2.5.5 Safe Shutdown

During a safe shutdown, the passive core cooling system provides redundancy for boration, makeup, and heat removal functions. Section 7.4 provides additional information about safe shutdown.

6.3.2.6 Protection Provisions

The measures taken to protect the system from damage that might result from various events are described in other sections, as listed below.

- Protection from dynamic effects is presented in Section 3.6.
- Protection from missiles is presented in Section 3.5.
- Protection from seismic damage is presented in Sections 3.7, 3.8, 3.9, and 3.10.
- Protection from fire is presented subsection 9.5.1.
- Environmental qualification of equipment is presented in Section 3.11.
- Thermal stresses on the reactor coolant system are presented in Section 5.2.

6.3.2.7 Provisions for Performance Testing

The passive core cooling system includes the capability for determination of the integrity of the pressure boundary formed by series passive core cooling system check valves. Additional information on testing can be found in subsection 6.3.6.

6.3.2.8 Manual Actions

The passive core cooling system is automatically actuated for those events as presented in subsection 6.3.3. Following actuation, the passive core cooling system continues to operate in the injection mode until the transition to recirculation initiates automatically following containment floodup.

Although the passive core cooling system operates automatically, operator actions would be beneficial, in some cases, in reducing the consequences of an event. For example, in a steam generator tube rupture with no operator action, the protection and safety monitoring system automatically terminates the leak, prevents steam generator overfill, and limits the offsite doses. However, the operator can initiate actions, similar to those taken in current plants, to identify and isolate the faulted steam generator, cool down and depressurize the reactor coolant system to terminate the break flow to the steam generator, and stabilize plant conditions.

Section 7.5 describes the post-accident monitoring instrumentation available to the operator in the main control room following an event.

6.3.3 Performance Evaluation

The events described in subsection 6.3.1 result in passive core cooling system actuation and are mitigated within the performance criteria. For the purpose of evaluation in Chapters 15 and 19, the events that result in passive core cooling system actuation are categorized as follows:

A. Increase in heat removal by the secondary system

   1. Inadvertent opening of a steam generator power-operated atmospheric steam relief or safety valve

   2. Steam system piping failure.

B. Decrease in heat removal by the secondary system

   1. Loss of Main Feedwater Flow
   2. Feedwater system piping failure.

C. Decrease in reactor coolant system inventory

   1. Steam generator tube rupture

   2. Loss of coolant accident from a spectrum of postulated reactor coolant system piping failures

3. Loss of coolant due to a rod cluster control assembly ejection accident

   (This event is enveloped by the reactor coolant system piping failures.)

D. Shutdown Events (Chapter 19)

1. Loss of Startup Feedwater

2. Loss of normal residual heat removal system with reactor coolant system pressure boundary intact

3. Loss of normal residual heat removal system during mid-loop operation

4. Loss of normal residual heat removal system with refueling cavity flooded.

The events listed in groups A and B are non-LOCA events where the primary protection is provided by the passive core cooling system passive residual heat removal heat exchanger. For these events, the passive residual heat removal heat exchanger is actuated by the protection and monitoring system for the following conditions:

- Steam generator low narrow range level, coincident with startup feedwater low flow
- Steam generator low wide range level
- Core makeup tank actuation
- Automatic depressurization actuation
- Pressurizer water level - High 3
- Manual actuation

The events listed in group C above are events involving the loss of reactor coolant where the primary protection is by the core makeup tanks and accumulators. For these events the core makeup tanks are actuated by the protection and monitoring system for the following conditions:

- Pressurizer low pressure

- Pressurizer low level

- Steam line low pressure

- Containment high pressure

- Cold leg low temperature

- Steam generator low wide range level, coincident with reactor coolant system high hot leg temperature

- Manual actuation

In addition to initiating passive core cooling system operation, these signals initiate other safeguards automatic actions including reactor trip, reactor coolant pump trip, feedwater isolation, and containment isolation. The passive core cooling system actuation signals are described in Section 7.3.

The core makeup tanks and passive residual heat removal heat exchangers are also actuated by the Diverse Actuation System as described in subsection 7.7.1.11.

Upon receipt of an actuation signal, the actions described in subsection 6.3.2.1 are automatically initiated to align the appropriate features of the passive core cooling system.

For non-LOCA events, the passive residual heat removal heat exchanger is actuated so that it can remove core decay heat.

For loss of coolant accidents, the core makeup tanks deliver borated water to the reactor coolant system via the direct vessel injection nozzles. The accumulators deliver flow to the direct vessel injection line whenever reactor coolant system pressure drops below the tank static pressure. The in-containment refueling water storage tank provides gravity injection once the reactor coolant system pressure is reduced to below the injection head from the in-containment refueling water storage tank. The passive core cooling system flow rates vary depending upon the type of event and its characteristic pressure transient.

As the core makeup tanks drain down, the automatic depressurization system valves are sequentially actuated. The depressurization sequence establishes reactor coolant pressure conditions that allow injection from the accumulators, and then from the in-containment refueling water storage tank and the containment recirculation path. Therefore, an injection source is continually available.

The events listed in group D occur during shutdown conditions that are characterized by slow plant responses and mild thermal-hydraulic transients. In addition, some of the passive core cooling system features need to be isolated to allow the plant to be in these conditions or to perform maintenance on the system. The protection and monitoring system automatically actuates gravity injection from the IRWST to provide core cooling during shutdown conditions prior to refueling cavity floodup. In addition, the operator can also manually actuate other passive core cooling system equipment, such as the passive residual heat removal heat exchanger, to provide core cooling during shutdown conditions when the equipment does not automatically actuate.

6.3.3.1 Increase in Heat Removal by the Secondary System

A number of events that could result in an increase in heat removal from the reactor coolant system by the secondary system have been postulated. For each event, consideration has been given to operation of nonsafety-related systems that could affect the event results. The operation of the startup feedwater system and the chemical and volume control system makeup pumps can affect these events. Analyses of these events, both with and without these nonsafety-related systems operating, are presented in Section 15.1. For those events resulting in passive core cooling system actuation, the following summarizes passive core cooling system performance.

6.3.3.1.1 Inadvertent Opening of a Steam Generator Relief or Safety Valve

Subsection 15.1.4 provides a description of an inadvertent opening of a steam generator relief or safety valve, including criteria and analytical results.

For this event, upon generation of a safeguards actuation signal the reactor is tripped, the core makeup tanks are actuated, and the reactor coolant pumps are tripped. Since the core makeup tanks are actuated, the passive residual heat removal heat exchanger is also actuated. The main steam lines are also isolated to prevent blowdown of more than one steam generator. The core makeup tanks operate with water recirculation injection to provide borated water to the reactor vessel downcomer plenum for reactor coolant system inventory and reactivity control. The trip of the reactor initially brings the reactor sub-critical. The rapid reactor coolant system cool down may result in the reactor returning to critical because the rate of positive reactivity addition (reactor coolant system temperature reduction) exceeds the rate of negative reactivity addition (boron from the core makeup tank). As the event continues, the reactor coolant system cooldown will slow down such that the continued core makeup tank boration will return the reactor sub-critical. The departure from nucleate boiling design basis is met, thereby preventing fuel damage.

During this event, the startup feedwater system is assumed to malfunction so that it injects water at the maximum flow rate. This injection continues until feedwater isolation occurs on low reactor coolant system temperature. The feedwater isolation signal terminates the feedwater addition from the startup feedwater system. The passive residual heat removal heat exchanger is also assumed to function in this event. This heat removal mechanism continues throughout the duration of the event.

For this event, the core makeup tanks operate in the water recirculation mode, providing boration and injection flow without draining. Therefore, the automatic depressurization system is not actuated on the lowering of the core makeup tank level.

Subsequent to stabilizing plant conditions and satisfying passive core cooling system termination criteria, the operator terminates passive core cooling system operation and initiates normal plant shutdown operations.

6.3.3.1.2 Steam System Pipe Failure

The most severe core conditions resulting from a steam system piping failure are associated with a double-ended rupture of a main steam line, occurring at zero power. Effects of smaller piping failures at higher power levels are bounded by the double-ended rupture at zero power. Subsection 15.1.5 provides a description of this event, including criteria and analytical results.

For this event, the passive core cooling system functions as described in subsection 6.3.3.1.1 for the inadvertent opening of a steam generator relief or safety valve. However, this piping failure constitutes a more severe cooldown transient. The malfunctioning of the startup feedwater system is considered as it was in the inadvertent steam generator depressurization. The trip of the reactor initially brings the reactor sub-critical. The rapid reactor coolant system cool down may result in the reactor returning to critical because the rate of positive reactivity addition (reactor coolant system temperature reduction) exceeds the rate of negative reactivity addition (boron from the core

makeup tank). As the event continues, the reactor coolant system cooldown will slow down such that the continued core makeup tank boration will return the reactor sub-critical. The departure from nucleate boiling design basis is met.

For this event, the reactor coolant system may depressurize sufficiently to permit the accumulators to deliver makeup water to the reactor coolant system. The core makeup tanks inject via water recirculation without draining. Therefore, the automatic depressurization system is not actuated on the lowering of the core makeup tank level. Subsequent to stabilizing plant conditions and satisfying passive core cooling system termination criteria, the operator terminates passive core cooling system operation and initiates a normal plant shutdown.

6.3.3.2 Decrease in Heat Removal by the Secondary System

A number of events have been postulated that could result in a decrease in heat removal from the reactor coolant system by the secondary system. For each event, consideration has been given to operation of nonsafety-related systems that could affect the consequences of an event. The operation of the startup feedwater system and the chemical and volume control system makeup pumps can affect these events. Analyses of these events, both with and without these nonsafety-related systems operating, are presented in Section 15.2. For those events resulting in passive core cooling system actuation, the following summarizes passive core cooling system performance.

6.3.3.2.1 Loss of Main Feedwater

The most severe core conditions resulting from a loss of main feedwater system flow are associated with a loss of flow at full power. The heat-up transient effects of loss of flow at reduced power levels are bounded by the loss of flow at full power. Subsection 15.2.7 provides a description of this event, including criteria and analytical results.

For this event, the passive residual heat removal heat exchanger is actuated. If the core makeup tanks are not initially actuated, they actuate later when passive residual heat exchanger cooling sufficiently reduces pressurizer level. The passive residual heat removal heat exchanger serves to remove core decay heat and the core makeup tanks inject a borated water solution directly into the reactor vessel downcomer annulus. Since the reactor coolant pumps are tripped on actuation of the core makeup tanks, the passive residual heat removal heat exchanger operates under natural circulation conditions. The core makeup tanks operate via water recirculation, without draining, to maintain reactor coolant system inventory. Therefore, the automatic depressurization system is not actuated on the lowering of the core makeup tank level. Since the event is characterized by a heat-up transient, the injection of negative reactivity is not required and is not taken credit for in the analysis to control core reactivity.

The reactor coolant system does not depressurize to permit the accumulators to deliver makeup water to the reactor coolant system. Subsequent to stabilizing plant conditions and satisfying passive core cooling system termination criteria, the operator terminates passive core cooling system operation and initiates a normal plant shutdown.

6.3.3.2.2 Feedwater System Pipe Failure

The most severe core conditions resulting from a feedwater system piping failure are associated with a double-ended rupture of a feed line at full power. Depending on break size and power level, a feedwater system pipe failure could cause either a reactor coolant system cooldown transient or a reactor coolant system heat-up transient. Only the reactor coolant system heat-up transient is evaluated as a feedwater system pipe failure, since the spectrum of cooldown transients is bounded by the steam system pipe failure analyses. The heat-up transient effects of smaller piping failures at reduced power levels are bounded by the double-ended feed line rupture at full power. Subsection 15.2.8 provides a description of this event, including criteria and analytical results.

For this event, the passive residual heat removal heat exchanger and the core makeup tanks are actuated. The passive residual heat removal heat exchanger serves to remove core decay heat, and the core makeup tanks inject a borated water solution directly into the reactor vessel downcomer. Since the reactor coolant pumps are tripped on actuation of the core makeup tanks, the passive residual heat removal heat exchanger operates under natural circulation conditions. The core makeup tanks operate via water recirculation to maintain reactor coolant system inventory. Since the event is characterized by a heat-up transient, the injection of negative reactivity is not required and is not taken credit for in the analysis to control core reactivity.

The reactor coolant system does not depressurize to permit the accumulators to deliver makeup water to the reactor coolant system. Subsequent to stabilizing plant conditions and satisfying passive core cooling system termination criteria, the operator terminates passive core cooling system operation and initiates normal plant shutdown operations.

6.3.3.3 Decrease in Reactor Coolant System Inventory

A number of events have been postulated that could result in a decrease in reactor coolant system inventory. For each event, consideration has been given to operation of nonsafety-related systems that could affect the consequences of the event. The operation of the startup feedwater system and the chemical and volume control system makeup pumps can affect these events. Analyses of these events, both with and without these nonsafety-related systems operating, are presented in Section 15.6. For those events which result in passive core cooling system actuation, the following summarizes passive core cooling system performance.

6.3.3.3.1 Steam Generator Tube Rupture

Although a steam generator tube rupture is an event that results in a decrease in reactor coolant system inventory, severe core conditions do not result from a steam generator tube rupture. The event analyzed is a complete severance of a single steam generator tube that occurs at power with the reactor coolant contaminated with fission products, corresponding to continuous operation with a limited amount of defective fuel rods. Effects of smaller breaks are bounded by the complete severance. Subsection 15.6.3 provides a description of this event, including criteria and analytical results.

For this event, the nonsafety-related makeup pumps are automatically actuated when reactor coolant system inventory decreases and a reactor trip occurs, followed by actuation of the startup

feedwater pumps. The startup feedwater flow initiates on low steam generator level following the reactor trip and automatically throttles feedwater flow to maintain programmed steam generator level, limiting overfill of the faulted steam generator. The makeup pumps automatically function to maintain the programmed pressurizer level. The operators are expected to take actions similar to those in current plants to identify and isolate the faulted steam generator, cooldown and depressurize the reactor coolant system to terminate the break flow into the steam generator, and stabilize plant conditions.

If the operator fails to take timely or correct actions in response to the leak, or if the makeup pumps and/or the startup feedwater pumps malfunction with excessive flow, then the water level in the faulted steam generator continues to increase. This actuates safety-related overfill protection and automatically isolates the startup feedwater pumps and the chemical and volume control system makeup pumps. The core makeup tanks subsequently actuate on low pressurizer level, if they are not already actuated. Actuation of the core makeup tanks automatically actuates the passive residual heat removal system heat exchanger.

The core makeup tanks operate via water recirculation to provide borated water directly into the reactor vessel downcomer to maintain reactor coolant system inventory. The passive residual heat removal heat exchanger serves to remove core decay heat. Since the reactor coolant pumps are automatically tripped on actuation of the core makeup tanks, the passive residual heat removal heat exchanger operates under natural circulation flow conditions. The passive residual heat removal heat exchanger, in conjunction with the core makeup tanks, remove core decay heat and reduce reactor coolant system temperature. As the reactor coolant system cools and the inventory contracts, pressurizer level and pressure decrease, equalizing with steam generator pressure and terminating break flow.

If the nonsafety-related systems fail to start, the core makeup tanks and the passive residual heat removal heat exchangers automatically actuate. Their response is similar to that previously described, except that the faulted steam generator level is lower.

In these events, the plant conditions are stabilized without actuating the automatic depressurization system. Once plant conditions are stable, the operator completes a normal plant shutdown.

6.3.3.3.2 Loss of Coolant Accident

A loss of coolant accident is a rupture of the reactor coolant system piping or branch piping that results in a decrease in reactor coolant system inventory that exceeds the flow capability of the normal makeup system. Ruptures resulting in break flow within the capability of the normal makeup system do not result in decreasing reactor coolant system pressure and actuation of the passive core cooling system. The maximum break size for which the normal makeup system can maintain reactor coolant system pressure is obtained by comparing the calculated flow from the reactor coolant system through the postulated break with the charging pump makeup flow at a reactor coolant system pressure that is above the low pressure safeguards actuation setpoint. The makeup flow rate from one makeup pump is adequate to maintain pressurizer pressure for a break through a 0.375-inch diameter hole. Therefore, the normal makeup system can maintain reactor coolant system pressure and permit the operator to execute an orderly shutdown.

For the purpose of evaluation, the spectrum of postulated piping breaks in the reactor coolant system is divided into major pipe breaks (large break) and minor pipe breaks (small breaks). The large break is a rupture with a total cross-sectional area equal to or greater than one square foot. The small break is defined as a rupture with a total cross-sectional area less than one square foot. Section 15.6 provides a description of this event, including criteria and analytical results.

For either event, the core makeup tanks are actuated upon receipt of a safeguards actuation signal. These tanks provide high-pressure injection. For large breaks, or after the automatic depressurization system is actuated, the accumulators also provide injection. After automatic depressurization system actuation, the in-containment refueling water storage tank, and the containment recirculation sump, provide low pressure injection.

The core makeup tanks can operate via water recirculation or steam-compensated injection during LOCAs. For smaller loss of coolant accidents, the reactor coolant system inventory is sufficient to establish water recirculation. For larger break sizes, when the pressurizer empties and voiding occurs in the cold legs steam-compensated injection initiates. When the cold legs void, the core makeup tank flow increases.

As the core makeup tanks drain, their level sequences the automatic depressurization system valve stages. As the level drops in the core makeup tank, the first-stage actuates. The first-stage valves are connected to the top of the pressurizer and discharge to the in-containment refueling water storage tank via the automatic depressurization system spargers. After a time delay, the second-stage is actuated. The second stage valves are connected with the same flow path as the first-stage valves. After an additional time delay, the third-stage is actuated. The third stage valves are identical to the second-stage valves. As the core makeup tank drops to a low level the fourth-stage is actuated. The fourth stage valves are connected to both hot legs and they discharge directly to the reactor coolant system loop compartments at an elevation just above the maximum containment flood-up level.

The in-containment refueling water storage tank line squib valves are opened on the fourth stage actuation signal. Check valves arranged in series with the squib valves remain closed until the reactor depressurizes. After depressurization, the in-containment refueling water storage tank provides injection flow. The flow continues until containment flood-up initiates containment recirculation.

For large breaks or following automatic depressurization system initiation, the accumulators provide rapid injection to the reactor vessel through the same connections used by the core makeup tanks and the in-containment refueling water storage tank injection. The accumulators begin to inject when the reactor coolant system depressurizes to about 700 psig. During the loss of coolant accident transient, flow to the reactor coolant system is dependent on the reactor coolant system pressure transient. The passive core cooling system water injected into the reactor coolant system provides for heat transfer from the core, prevents excessive core clad temperatures, and refloods the core (for large loss of coolant accidents) or keeps the core covered (for small loss of coolant accidents).

For small loss of coolant accidents, the control rods provide the initial core shutdown and the boron in the passive core cooling system tanks add negative reactivity to provide adequate shutdown at low temperatures.

Following the initial thermal-hydraulic transient for a loss of coolant accident event, the passive core cooling system continues to supply water to the reactor coolant system for long-term cooling. When the water level in the in-containment refueling water storage tank drops to a low-low level, the water level in the containment has increased to a sufficient level to provide recirculation flow. The in-containment refueling water storage tank low-low level signal opens the squib valves in the lines between the containment and the gravity injection line. Initially, some of the water remaining in the tank drains to the containment until the water levels equalize. During this drain, injection to the core continues. The redundant flow paths provide continued cooling of the core by recirculation of the water in the containment. Figure 6.3-3 provides process flow information illustrating passive core cooling system performance for the various modes of system operation.

6.3.3.3.3 Passive Residual Heat Removal Heat Exchanger Tube Rupture

Although a passive residual heat removal heat exchanger tube rupture is an event that results in a decrease in reactor coolant system inventory, severe core conditions do not result from this event. There is a spectrum of heat exchanger tube leak sizes that are possible. For a small initiating leak, the passive core cooling system temperature instrumentation for the heat exchanger is used to identify that this is a heat exchanger leak. If the leak rate is less than the Technical Specification limits, plant operation can continue indefinitely. If the leak rate exceeds the Technical Specification limits the plant would be shut down to repair the heat exchanger.

If a severe tube leak occurs, the operators can use available instrumentation to identify the leak source. Action can then be taken to remotely isolate the heat exchanger by closing the motor-operated inlet isolation valve, which is normally open. The plant would be shut down to repair the heat exchanger.

This event is addressed in Section 15.6.

6.3.3.4 Shutdown Events

The passive core cooling system components are available whenever the reactor is critical and when reactor coolant energy is sufficiently high to require passive safety injection. During low-temperature physics testing, the core decay heat levels are low and there is a negligible amount of stored energy in the reactor coolant. Therefore, an event comparable in severity to events occurring at operating conditions is not possible and passive core cooling system equipment is not required. The possibility of a loss of coolant accident during plant startup and shutdown has been considered.

During shutdown conditions, some of the passive core cooling system equipment is isolated. In addition, since the normal residual heat removal system is not a safety-related system, its loss is considered.

As a result, gravity injection is automatically actuated when required during shutdown conditions prior to refueling cavity floodup, as discussed in subsection 6.3.3.3.2. The operator can also manually actuate other passive core cooling system equipment, such as the passive residual heat removal heat exchanger, if required for accident mitigation during shutdown conditions when the equipment does not automatically actuate.

6.3.3.4.1 Loss of Startup Feedwater During Hot Standby, Cooldowns, and Heat-ups

During normal cooldowns, the steam generators are supplied by the startup feedwater pumps and steam from the steam generator is directed to either the main condenser or to the atmosphere. There are two nonsafety-related startup feedwater pumps, each of which is capable of providing sufficient feedwater flow to both steam generators to remove decay heat. These pumps are also automatically loaded on the nonsafety-related diesel-generators in the event offsite power is lost. Since these pumps are nonsafety-related, their failure is considered.

In the event of a loss of startup feedwater, the passive residual heat removal heat exchanger is automatically actuated on low steam generator water level and provides safety-related heat removal. The passive residual heat removal heat exchanger can maintain the reactor coolant system temperature, as well as provide for reactor coolant system cooldown to conditions where the normal residual heat removal system can be operated.

Since the chemical and volume control system makeup pumps are nonsafety-related, they may not be available. In this case, the core makeup tanks automatically actuate as the cooldown continues and the pressurizer level decreases. The core makeup tanks operate in a water recirculation mode to maintain reactor coolant system inventory while the passive residual heat removal heat exchanger is operating.

The in-containment refueling water storage tank provides the heat sink for the passive residual heat removal heat exchanger. Initially, the heat addition increases the water temperature. Within one to two hours, the water reaches saturation temperature and begins to boil. The steam generated in the in-containment refueling water storage tank discharges to containment. Because the containment integrity is maintained during cooldown Modes 3 and 4, the passive containment cooling system provides the safety-related ultimate heat sink. Therefore, most of the steam generated in the in-containment refueling water storage tank is condensed on the inside of the containment vessel and drains back into the in-containment refueling water storage tank via the condensate return gutter arrangement. This allows it to indefinitely function as a heat sink.

6.3.3.4.2 Loss of Normal Residual Heat Removal Cooling With The Reactor Coolant System Pressure Boundary Intact

During normal shutdown conditions, the normal residual heat removal system is placed into service at about 350°F to accomplish reactor coolant system cooldown to refueling temperatures. The normal residual heat removal system piping is safety-related and meets seismic Category I requirements to prevent pipe breaks that could result in a significant loss of reactor coolant during system operation. The pump motors and the electrical power supplies are nonsafety-related.

The system is designed so that with single failure of an active system component, it can maintain the plant in a hot shutdown condition (<350°F). It is also possible to perform a reactor coolant system cooldown, but at a slower rate than with full system capability. Heat removed by the normal residual heat removal system is transferred to the component cooling water system and then to the service water system. The heat removal path is powered by the nonsafety-related diesel-generators in the event that offsite power is lost.

Since the normal residual heat removal pumps are nonsafety-related, they may not be available. In this case, the reactor coolant system pressure boundary remains intact and the passive residual heat removal heat exchanger provides the safety-related heat removal flow path.

The normal residual heat removal system is operated once the reactor coolant system temperature is too low to support sufficient steam production for decay heat removal. With a loss of shutdown cooling, the reactor coolant system temperature does not increase sufficiently to initiate steam generator steaming and to reduce steam generator level. This is because the steam generators are normally filled, with a nitrogen purge established, during shutdown conditions. The loss of cooling would result in the heat up of the reactor coolant system and a pressure increase resulting in the normal residual heat removal system relief valve opening. This loss of fluid would result in a decrease in the pressurizer level; which a low pressurizer level signal automatically actuates the core make tanks and the passive residual heat removal heat exchanger. The passive residual heat removal heat exchanger could also be manually actuated.

The passive residual heat removal heat exchanger is capable of functioning at low reactor coolant system temperatures and pressures, but it may not be able to maintain the initial reactor coolant system temperature. It can remove sufficient heat to maintain the reactor coolant system within the normal residual heat removal system design limits (400°F). This permits the normal residual heat removal system to be placed back in operation when it becomes available.

For this event, the reactor coolant system temperature is expected to increase and expand into the pressurizer. Reactor coolant system injection should not be required. The makeup pumps are aligned for automatic operation in the event that pressurizer level decreases, due to leakage. However, since they are nonsafety-related, they are considered unavailable for reactor coolant system makeup. Therefore should safety-related makeup be required, the core makeup tanks would automatically actuate and operate via water recirculation injection. For some scenarios, the core makeup tanks could drain down and actuate the automatic depressurization system valves. This would lead to injection via the in-containment refueling water storage tank and containment recirculation paths.

6.3.3.4.3 Loss of Normal Residual Heat Removal Cooling During Reduced Inventory

During reactor coolant system maintenance, the most limiting shutdown condition anticipated is with the reactor coolant level reduced and the reactor coolant system pressure boundary opened. It is normal practice to open the steam generator channel head manway covers to install the hot leg and cold leg nozzle dams during a refueling outage. In this situation, the normal residual heat removal system is used to cool the reactor coolant system. The AP1000 incorporates many features to reduce the probability of losing the normal residual heat removal system. However,

since the normal residual heat removal system is nonsafety-related, its failure has been considered. The normal residual heat removal system is described subsection 5.4.7.

In reduced inventory operation with the reactor coolant system depressurized and the pressure boundary opened, the passive residual heat removal heat exchanger is unable to remove the decay heat because the reactor coolant system cannot heat sufficiently above the in-containment refueling water storage tank temperature.

In this situation, core cooling is provided by the safety-related passive core cooling system, using gravity injection from the in-containment refueling water storage tank, while venting through the automatic depressurization system valves (and possibly through other openings in the reactor coolant system).

Prior to draining the reactor coolant system inventory below the no-load pressurizer level, the core makeup tanks are isolated to preclude inadvertent draining into the reactor coolant system while preparing for midloop operation. During plant shutdown, at 1000 psig, the accumulators are isolated to prevent inadvertent injection. In this configuration, the core makeup tanks and accumulators are isolated from the reactor coolant system, however these valves can be remotely opened with operator action to provide additional makeup water injection, if required.

Before the core makeup tanks are isolated, the automatic depressurization first-, second-, and third-stages valves are opened manually be the operators. The automatic depressurization system first-, second- and third-stage valves are required to remain open whenever the reactor coolant inventory is reduced or the upper core internals are in place. During an extended loss of normal residual heat removal system operation the stage one, two and three vent paths may not provide sufficient vent capability to allow gravity injection of water from the in-containment refueling water storage tank because of pressurizer surge line flooding. As a result, two of the automatic depressurization stage four paths are required to be operable in these conditions. The stage four valves are automatically opened by a signal from the protection and monitoring system on a low hot leg level signal following a time delay.

The in-containment refueling water storage tank injection squib valves automatically open via the same low hot leg level signal that opens the automatic depressurization stage four valves. The operators can also open these injection and depressurization valves via the diverse actuation system. Once these valves open, injection from the in-containment refueling water storage tank provides gravity injection for core cooling. When the in-containment refueling water storage tank level drops to a low level, the squib valves in the containment recirculation line automatically open. This action initiates containment recirculation flow, with flow passing through the in-containment refueling water storage tank gravity injection lines, which provides long-term core cooling.

This arrangement provides automatic core cooling protection, while in reduced inventory operation while also providing protection (an evacuation alarm and sufficient time to evacuate) for maintenance personnel in containment during midloop operation. The time delay also provides the operators with time to take actions to restore nonsafety-related decay heat removal prior to actuating the passive core cooling system.

During reduced inventory conditions the capability of closing the containment is required. After the containment is closed, containment recirculation can continue indefinitely, with the decay heat generating steam which condenses on the containment vessel and drains back into the in-containment refueling water storage tank.

6.3.3.4.4 Loss of Normal Residual Heat Removal Cooling During Refueling

The normal residual heat removal system is normally used for decay heat removal during refueling operation. Its failure is considered because it is not a safety-related system. In this case, it is assumed that the reactor vessel head is removed and the water from the in-containment refueling water storage tank has been transferred to the refueling cavity, which is flooded to its high level condition. The passive residual heat removal heat exchanger is not available and containment integrity is expected to be relaxed with air locks and/or equipment hatches open.

Assuming that the refueling cavity was just flooded when the normal residual heat removal system fails, the refueling cavity water heats up to saturation temperature in about nine hours. With the slow heat-up of the refueling cavity water, there is ample time to close containment before significant steaming to the containment begins. The Technical Specifications require that containment closure capability be maintained during refueling MODES such that closure of the containment can be assumed. With the containment closed, water will not be lost from containment and long-term cooling can be maintained without subsequent need for cooling water makeup. Without closing the containment, boiling would reduce the water level to the top of the fuel assemblies in about five days.

6.3.4 Post-72 Hour Actions

The AP1000 passive core cooling system design includes safety-related equipment that is sufficient to automatically establish and maintain safe shutdown conditions for the plant following design basis events. The passive core cooling system can maintain safe shutdown conditions for 72 hours after an event without operator action and without both nonsafety-related onsite and offsite power.

There is only one action that may be required to provide long-term core cooling. There is a potential need for containment inventory makeup. The need for makeup to containment is directly related to the leakrate from the containment. With the maximum allowable containment leakrate, makeup to containment is not needed for about one month. A safety-related connection is available in the normal residual heat removal system to align a temporary makeup source to containment.

6.3.5 Limits on System Parameters

The analyses show that the design basis performance of the passive core cooling system is sufficient to meet the core cooling requirements following an event, with the minimum engineered safety features equipment operating. To provide this capability in the event of the single failure of components, technical specifications are established for reactor operation. The technical specifications are provided in Chapter 16.

The passive core cooling system equipment is not required to operate to support either normal power operation or shutdown operation of the plant. This reduces the probability that the passive core cooling system equipment is unavailable due to maintenance. Planned maintenance on the passive core cooling system equipment is accomplished during shutdown operations when the core temperatures are low, decay heat levels are low, and the Technical Specifications do not require availability of the equipment.

The principal system parameters and the number of components that may be out of operation during testing, quantities and concentrations of coolant available, and allowable time for operation in a degraded status are provided in the technical specifications.

If efforts to restore the operable status of the passive core cooling system equipment are not accomplished within technical specification requirements, the plant is required to be placed in a lower operational mode.

6.3.6 Inspection and Testing Requirements

6.3.6.1 Preoperational Inspection and Testing

Preoperational inspections and tests of the passive core cooling system are performed to verify the operability of the system prior to loading fuel. This testing includes valve inspection and testing, flow testing, and verification of heat removal capability.

Preoperational testing of the passive core cooling system is completed in conjunction with testing of the reactor coolant system following flushing and hydrostatic testing, with the system cold and the reactor vessel head removed. The passive core cooling system is aligned for normal power operation. This testing provides the following information:

- Satisfactory safeguards actuation signal generation and transmission
- Valve operating times
- Injection starting times
- Injection delivery rates

The preoperational testing program includes testing of the following passive core cooling system components:

- Core makeup tanks
- Accumulators
- In-containment refueling water storage tank
- Containment recirculation
- Passive residual heat removal heat exchanger

Conformance with the recommendations of Regulatory Guide 1.79 is described in subsection 1.9.1. Preoperational testing of the passive core cooling system is conducted in accordance with the requirements presented in subsection 14.2.9.1.3.

6.3.6.1.1 Flow Testing

Initial verification of the resistance of the passive core cooling injection lines is performed by conducting a series of flow tests for the core makeup tanks, accumulators, in-containment refueling water storage tank, and containment recirculation piping. The calculated flow resistances are bounded by the resistances used in the Chapter 15 safety analyses.

6.3.6.1.2 Heat Transfer Testing

Initial verification of the heat transfer capability of the passive residual heat removal heat exchanger is performed by conducting a natural circulation test. This test is conducted during hot functional testing of the reactor coolant system. Measurements of heat exchanger flow rate and inlet and outlet temperatures are recorded, and calculations are performed to verify that the heat transfer performance of the heat exchanger is greater than that provided in Table 6.3-2.

6.3.6.1.3 Preoperational Inspections

Preoperational inspections are performed to verify that important elevations associated with the passive core cooling system components are consistent with the accident analyses presented in Chapter 15. The following elevations are verified:

– The bottom inside surface of each core makeup tank is at least 7.5 feet above the direct vessel injection nozzle centerline.

– The bottom inside surface of the in-containment refueling water storage tank is at least 3.4 feet above the direct vessel injection nozzle centerline.

– The centerline of the upper passive residual heat removal heat exchanger channel head is at least 26.3 feet above the hot leg centerline.

– The pH baskets are located below plant elevation 107 feet, 2 inches.

Inspections of the passive core cooling system tanks and pH adjustment baskets are conducted to verify that the actual tank volumes are greater than or equal to volume assumed in the Chapter 15 accident analyses. Inspections to determine dimensions of the core makeup tanks, accumulators, in-containment refueling water storage tank, and pH adjustment baskets are conducted, and calculations are performed to verify that actual volume is not less than the corresponding minimum required volume listed in Table 6.3-2.

6.3.6.2 In-Service Testing and Inspection

In-service testing and inspection of the passive core cooling system components and the associated support systems are planned. The passive core cooling system components and systems are designed to meet the intent of the ASME Code, Section XI, for in-service testing. A description of the in-service testing program is provided in subsection 3.9.6.

Two basic types of in-service testing are performed on the passive core cooling system components:

- Periodic exercise testing of active components during power operation (for example, cycling of specific valves)
- Operability testing of specific passive core cooling system features during plant shutdown (for example, accumulator injection flow to the reactor vessel or leak testing of containment isolation valves during selected plant shutdown.

The passive core cooling system includes specific features to support in-service test performance:

- Remotely operated valves can be exercised during routine plant maintenance
- Level, pressure, flow, and valve position instrumentation is provided for monitoring required passive core cooling system equipment during plant operation and testing
- Permanently installed test lines and connections are provided for operability testing

6.3.7 Instrumentation Requirements

Instrumentation channels employed for actuation of passive core cooling system operation are described in Section 7.3. This subsection describes the instrumentation provided for monitoring passive core cooling system components during normal plant operation and also during passive core cooling system post-accident operation. Alarms are annunciated in the main control room.

6.3.7.1 Pressure Indication

6.3.7.1.1 Accumulator Pressure

Two pressure channels are installed on each accumulator. The pressure indications are used to confirm that accumulator pressure is within bounds of the assumptions used in the safety analysis. Each channel provides pressure indication in the main control room and also provides high-pressure and low-pressure alarms.

6.3.7.1.2 Passive Residual Heat Removal Heat Exchanger Pressure

One pressure indicator is installed on the passive residual heat removal heat exchanger inlet line. The pressure indication is used to assist the operators in determining if there is a leak in the passive residual heat removal heat exchanger. The instrument provides pressure indication in the main control room.

6.3.7.2 Temperature Indication

6.3.7.2.1 Core Makeup Tank Inlet Line Temperature

Individual temperature channels are installed on the inlet line for each core makeup tank. The temperature indication is used to determine if there is a sufficient thermal gradient for system

operation. Each channel provides temperature indication in the main control room and also provides a low-temperature alarm.

6.3.7.2.2 Passive Residual Heat Removal Heat Exchanger Inlet Temperature

One temperature channel is installed on the inlet line to the passive residual heat removal heat exchanger. The temperature indication is used to detect reactor coolant system leakage into the passive residual heat removal heat exchanger, either through the discharge valves or from tube leakage into the in-containment refueling water storage tank, and to identify the leakage path. The channel provides temperature indication in the main control room and also provides a high-temperature alarm.

6.3.7.2.3 In-Containment Refueling Water Storage Tank Temperature

Four temperature channels are installed on the in-containment refueling water storage tank. The temperature indications are used to confirm that in-containment refueling water storage tank temperature is within the bounds of the assumptions used in the safety analysis. The temperature indications are also used to monitor in-containment refueling water storage tank temperature during passive core cooling system operation. Each channel provides temperature indication and high-temperature alarms in the main control room.

6.3.7.2.4 Core Makeup Tank Outlet Line Temperature

Two temperature channels are installed, one on each core makeup tank outlet line. The temperature indication is used to detect reactor coolant system leakage into the core makeup tanks. Each channel provides temperature indication in the main control room and also provides a high-temperature alarm.

6.3.7.2.5 Direct Vessel Injection Line Temperature

Two temperature channels are installed, one on each direct vessel injection line. The temperature indication is used to detect reactor coolant system leakage back through the direct vessel injection lines to the core makeup tanks, accumulator, or in-containment refueling water storage tank. Each channel provides temperature indication in the main control room.

6.3.7.2.6 Passive Residual Heat Removal Heat Exchanger Inlet High Point Temperature

One temperature channel is installed on the passive residual heat removal heat exchanger inlet line. The temperature indication is used to determine that the temperature in the inlet is within the bounds of the assumptions used in the safety analysis. The channel provides temperature indication and a low temperature alarm in the main control room.

6.3.7.3 Passive Residual Heat Removal Heat Exchanger Outlet Flow Indication

Two flow channels are installed on the passive residual heat removal outlet line. The flow indications are used to monitor and control passive residual heat removal heat exchanger operation. Each channel provides flow indication in the main control room.

6.3.7.4 Level Indication

6.3.7.4.1 Core Makeup Tank Level

Ten level channels are installed on each core makeup tank. There are 2 wide range level channels which are used to confirm that the core makeup tanks are maintained at full water level during normal operation. There are four narrow range level channels which are used to control the actuation of the automatic depressurization system stage 1 valves. There are four narrow range level channels which are used to control the actuation of the automatic depressurization system stage 4 valves. Each wide range channel provides level indication and alarms in the main control room. Each narrow range channel provides discrete level setpoints for indications and alarms in the main control room and for actuation of the automatic depressurization system. Each set of four narrow range channels share upper and lower level tap connections with the core makeup tanks; a failure modes and effects analysis confirms the ability of this arrangement to tolerate single failures (Reference 2).

6.3.7.4.2 Accumulator Level

Two level channels are installed on each accumulator. The level indications are used to confirm that accumulator level is within bounds of the assumptions used in the safety analysis. Each channel provides level indication and both high and low level alarms in the main control room.

6.3.7.4.3 In-Containment Refueling Water Storage Tank Level

Six level channels are installed on the in-containment refueling water storage tank. There are two narrow range channels. These level indications are used to confirm that in-containment refueling water storage tank level is within the bounds of the assumptions used in the safety analysis. There are four wide range level channels. These level indications are used to provide containment recirculation valve repositioning. Each channel provides level indication in the main control room and provides level alarms.

The in-containment refueling water storage tank is sized and the level alarm setpoints selected to provide adequate in-containment refueling water storage tank injection (and spill flow to containment for a direct vessel injection line break) until containment flood-up is sufficient to provide recirculation flow.

6.3.7.4.4 Containment Level

Three level channels are installed on the containment. The level indications are used to monitor containment level from the reactor vessel cavity up to the maximum containment flood-up elevation. Each channel provides level indication and alarms in the main control room.

6.3.7.5 Containment Radiation Level

Four channels are installed for the containment radiation. The radiation indications are used to monitor containment conditions. Each channel provides radiation indication and high radiation alarms in the main control room. Section 11.5 provides additional information.

6.3.7.6 Valve Position Indication and Control

6.3.7.6.1 Valve Position Indication

Individual valve position is provided for the safety-related, remotely actuated valves listed in Table 6.3-1. In addition, valve position is provided for certain manually operated valves, as described in subsection 6.3.2.2.8.2, that can isolate redundant passive core cooling equipment, if mispositioned. The incontainment refueling water injection check valves, containment recirculation check valves, accumulator check valves, and the core makeup tank check valves have nonintrusive position indication.

For passive core cooling system valves with position indication, alarms in the main control room are provided to alert the operators to valve mispositioning.

6.3.7.6.2 Valve Position Control

Valve controls are provided for remotely operated passive core cooling system valves. Table 6.3-1 provides a list of the passive core cooling system remotely operated valves. These remotely operated valves have controls in the main control room. This table also provides references to specific sections in DCD Chapter 7 that provide additional descriptions of the valve controls.

6.3.7.6.2.1 Accumulator Motor-Operated Valve Controls

As part of the plant shutdown procedures, the operator is required to close the accumulator motor-operated valves. This prevents a loss of accumulator water inventory to the reactor coolant system when the reactor coolant system is depressurized. The valves are closed after the reactor coolant system has been depressurized to below the setpoint to block the safeguards actuation signal. The redundant pressure and level alarms on each accumulator function to alert the operator to close these valves, if any are inadvertently left open. Power is locked out after the valves are closed. During plant startup, the operator is directed by plant procedures to energize and open these valves prior to reaching the reactor coolant system pressure setpoint that unblocks the safeguards actuation signal. Redundant indication and alarms are available to alert the operator if a valve is inadvertently left closed once the reactor coolant system pressure increases beyond the setpoint. Power is also locked out after these valves are opened.

The accumulator isolation valves are not required to move during power operation. For a description of limiting conditions for operation and surveillance requirements of these valves, refer to the technical specifications. The accumulator isolation valves receive a safeguards actuation signal to confirm that they are open in the event of an accident. As a result of the power lock out, technical specifications, and the redundant position indication and alarms, the valve controls are nonsafety-related.

6.3.7.6.2.2 In-Containment Refueling Water Storage Tank Injection Motor-Operated Valve Controls

The motor-operated valves in each in-containment refueling water storage tank injection line are normally open during all modes of normal plant operation. Power to these valves is locked out. Redundant valve position indication and alarms are provided to alert the operator if a valve is

inadvertently closed. The technical specifications specify surveillances to show that these valves are open. These valves also receive a safeguards actuation signal to confirm that they are open in the event of an accident. As a result of the power lock out, the redundant position indication and alarms and the technical specifications the valve controls are nonsafety-related.

6.3.7.6.2.3 Passive Residual Heat Removal Heat Exchanger Inlet Motor-Operated Valve Control

The motor-operated valve in the passive residual heat removal heat exchanger inlet line is normally open during normal plant operation. Power to this valve is locked out. Redundant valve position indications and alarms are provided to alert the operator if the valve is open. This valve also receives an actuation signal to confirm that it is open in the event of an accident.

6.3.7.7 Automatic Depressurization System Actuation at 24 Hours

A timer is used to automatically actuate the automatic depressurization system if offsite and onsite power are lost for about 24 hours. This prevents discharging the Class 1E dc power sources such that they are no longer able to operate the automatic depressurization system valves. If power becomes available to the dc batteries and they are no longer discharging prior to activation of the timer, then the automatic depressurization system actuation would be delayed. If the plant does not need actuation of the automatic depressurization system based on having stable pressurizer level, full core makeup tanks, and high and stable in-containment refueling water storage tank levels, the operators are directed to de-energize all loads on the 24-hour batteries. This action will block actuation of the automatic depressurization system and allow for its actuation later should the plant conditions unexpectedly degrade.

6.3.8 Combined License Information

6.3.8.1 Containment Cleanliness Program

The Combined License applicants referencing the AP1000 will address preparation of a program to limit the amount of debris that might be left in the containment following refueling and maintenance outages. The cleanliness program will limit the storage of outage materials (such as temporary scaffolding and tools) inside containment during power operation consistent with COL item 6.3.8.2.

6.3.8.2 Verification of Water Sources for Long-Term Recirculation Cooling Following a LOCA

The Combined License applicants referencing the AP1000 will perform an evaluation consistent with Regulatory Guide 1.82, revision 3, and subsequently approved NRC guidance, to demonstrate that adequate long-term core cooling is available considering debris resulting from a LOCA together with debris that exists before a LOCA. As discussed in DCD subsection 6.3.2.2.7.1, a LOCA in the AP1000 does not generate fibrous debris due to damage to insulation or other materials included in the AP1000 design. The evaluation will consider resident fibers and particles that could be present considering the plant design, location, and containment cleanliness program. The determination of the characteristics of such resident debris will be based on sample measurements from operating plants. The evaluation will also consider the potential for the generation of chemical debris (precipitants). The potential to generate such debris will be

determined considering the materials used inside the AP1000 containment, the post-accident water chemistry of the AP1000, and the applicable research/testing.

6.3.9 References

1. WCAP-8966, "Evaluation of Mispositioned ECCS Valves," September 1977.

2. WCAP-13594 (P), WCAP-13662 (NP), "FMEA of Advanced Passive Plant Protection System," Revision 1, June 1998.

Table 6.3-1

PASSIVE CORE COOLING SYSTEM - REMOTE ACTUATION VALVES

	Normal Position	Actuation Position	Failed Position	Notes
Core Makeup Tanks				
CMT inlet isolation MOV (V002A/B)	Open	Open	As is	(1,4)
CMT outlet isolation AOV (V014A/B,V015A/B)	Closed	Open	Open	
Accumulators				
Accumulator discharge MOV (V027A/B)	Open	Open	As is	(2,4)
In-Containment Refueling Water Storage Tank				
IRWST injection line MOV (V121A/B)	Open	Open	As is	(2,4)
IRWST injection line squib (V123A/B, V125A/B)	Closed	Open	As is	
Containment Recirculation Sump Valves				
Recirculation line MOVs (V117A/B)	Open	Open	As is	(2,4)
Recirculation line squib valves (V118A/B, 120A/B)	Closed	Open	As is	
Passive Residual Heat Removal Heat Exchanger				
PRHR HX inlet MOV (V101)	Open	Open	As is	(2,4)
PRHR HX outlet AOVs (V108A/B)	Closed	Open	Open	
IRWST gutter isolation AOVs (V130A/B)	Open	Closed	Closed	
Automatic Depressurization System Valves				
ADS Stage 1 MOVs (V001A/B, V011A/B)	Closed	Open	As is	
ADS Stage 2 MOVs (V002A/B, V012A/B)	Closed	Open	As is	
ADS Stage 3 MOVs (V003A/B, V013A/B)	Closed	Open	As is	
ADS Stage 4 MOVs (V014A/B/C/D)	Open	Open	As is	(3)
ADS Stage 4 squib valves (V004A/B/C/D)	Closed	Open	As is	

Notes:
(1) These valves are normally in the correct post-accident position, but receive confirmatory actuation signals to redundant controllers.
(2) These valves are normally in the correct post-accident position with their power locked out. They also receive confirmatory actuation signals.
(3) These valves are normally in the correct post-accident position, but receive confirmatory actuation signals.
(4) The operation of these valves is not safety-related.

Table 6.3-2 (Sheet 1 of 2)

COMPONENT DATA - PASSIVE CORE COOLING SYSTEM

Passive RHR HX		
Number	1	
Type	Vertical C-Tube	
Case	Design	
Heat transfer (BTU/hr)	2.01 E+08	
	Tube side	Shell side
Fluid	Reactor coolant	IRWST water
Design flow (lb/hr)	5.03 E+05	N/A
Temperature in (°F)	567	120
out (°F)	199	N/A
Design pressure (psig)	2485	N/A
Design temperature (°F)	650	N/A
Material	Alloy 690	N/A
AP1000 equipment class	A	N/A
Core Makeup Tanks		
Number	2	
Type	Vertical, cylindrical, hemispherical heads	
Volume (cubic feet)	2500	
Design pressure (psig)	2485	
Design temperature (°F)	650	
Material	Carbon-steel, stainless steel clad	
AP1000 equipment class	A	
Accumulators		
Number	2	
Type	Spherical	
Volume (cubic feet)	2000	
Design pressure (psig)	800	
Design temperature (°F)	300	
Material	Carbon-steel, stainless steel clad	
AP1000 equipment class	C	

Table 6.3-2 (Sheet 2 of 2)

COMPONENT DATA - PASSIVE CORE COOLING SYSTEM

IRWST		
Number	1	
Type	Integral to containment internal structure	
Volume, minimum water (cubic feet)	73,900	
Design pressure (psig)	5	
Design temperature (°F)	150 *	
Material	Wetted surfaces are stainless steel	
AP1000 equipment class	C	
Spargers		
Number	2	
Type	Cruciform	
Flow area of holes (in^2)	274	
Design pressure (psig)	600	
Design temperature (°F)	500	
Material	Stainless Steel	
AP1000 equipment class	C	
pH Adjustment Baskets		
Number	4	
Type	Rectangular	
Volume minimum total (cubic feet)	560	
Material	Stainless steel	
AP1000 equipment class	C	
Screens	IRWST	Containment Recirculation
Number	2	2
Surface area, trash rack (square feet)	≥70	≥70
Surface area, fine screen (square feet)	≥140	≥140
Material	Stainless steel	Stainless steel
AP1000 equipment class	C	C

Note:
* Several times during plant life, the refueling water could reach 250°F.

Table 6.3-3 (Sheet 1 of 4)

FAILURE MODE AND EFFECTS ANALYSIS - PASSIVE CORE COOLING SYSTEM ACTIVE COMPONENTS

Component	Failure Mode	Plant Condition	Effect on System Operation	Failure Detection Method	Remarks
CMT outlet isolation AOVs V014A/B, V015A/B Normally closed/ fail open	Failure to open on demand	All design basis events	No safety-related effect since each valve has a redundant, parallel isolation AOV, actuated by a separate division, which provides flow through a parallel branch line for the affected CMT. The other CMT is unaffected.	Valve position indication alarm in MCR and at RSW	
CMT discharge line check valves V016A/B, V017A/B Normally open	Failure to close on reverse flow	All design basis events	No safety-related effect since each valve has a redundant, series check valve which closes to prevent reverse flow, during a cold leg (large) LOCA or cold leg balance line break, preventing accumulator flow from bypassing the reactor vessel.	Valve position indication alarm in MCR and at RSW	
Accumulator nitrogen supply/vent valves V021A/B, V045 Normally closed/ fail closed	Spurious opening	All design basis events	No safety-related effect since each valve has either a normally closed redundant, series isolation SOV or a check valve in each vent flow path, that prevents accumulator nitrogen from leaking out of the accumulator, which could degrade accumulator injection.	No valve position indication Accumulator low pressure alarm in MCR and at RSW	
Accumulator nitrogen supply containment isolation AOV V042 Normally open/ fail closed	Failure to close on demand	All design basis events	No safety-related effect since each valve has a redundant, series isolation check valve which independently closes on reverse flow in the line, preventing reactor coolant from leaking out of containment.	Valve position indication alarm in MCR and at RSW	
Accumulator nitrogen supply containment isolation check valve V043 Normally open	Failure to close on reverse flow	All design basis events	No safety-related effect since each valve has a redundant, series isolation AOV, actuated by a separate division, which closes to prevent reactor coolant from leaking out of containment.	No valve position indication	

Table 6.3-3 (Sheet 2 of 4)

FAILURE MODE AND EFFECTS ANALYSIS - PASSIVE CORE COOLING SYSTEM ACTIVE COMPONENTS

Component	Failure Mode	Plant Condition	Effect on System Operation	Failure Detection Method	Remarks
PRHR HX outlet line isolation AOVs V108A/B Normally closed/ fail open	Failure to open	All design basis events	No safety-related effect since each valve has a redundant, parallel isolation AOV, actuated by a separate division, which opens to provide PRHR HX flow through a parallel branch line.	Valve position indication alarm in MCR and at RSW PRHR HX flow indication in MCR & RSW	
IRWST gravity injection line check valves V122A/B, V124A/B Normally closed	Failure to open	All design basis events	No safety-related effect since each valve has a redundant flow path through a check valve and a squib valve that open to provide gravity injection through a parallel branch line. The other IRWST gravity injection line is unaffected.	Valve position indication alarm in MCR and at RSW	
IRWST gravity injection line squib valves V123A/B, V125A/B Normally closed/ fail as is	Failure to open	All design basis events	No safety-related effect since each valve has a redundant flow path through a check valve and a squib valve that open to provide gravity injection through a parallel branch line. The other IRWST gravity injection line is unaffected.	Valve position indication alarm in MCR and at RSW	
IRWST gutter isolation valves V130A/B Normally open/fail closed	Failure to close	All design basis events	No safety-related effect since each valve has a redundant, series isolation AOV, actuated by a separate division, which closes to divert the gutter flow into the IRWST.	Valve position indication alarm in MCR and at RSW	
Containment recirculation line check valves V119A/B Normally closed	Failure to open	All design basis events	No safety-related effect since each valve has a redundant flow path through a MOV and a squib valve, actuated by separate divisions, that open to provide recirculation through a parallel branch line. The other containment recirculation line is unaffected.	Valve position indication alarm in MCR and at RSW	

Table 6.3-3 (Sheet 3 of 4)

FAILURE MODE AND EFFECTS ANALYSIS - PASSIVE CORE COOLING SYSTEM ACTIVE COMPONENTS

Component	Failure Mode	Plant Condition	Effect on System Operation	Failure Detection Method	Remarks
Containment recirculation line squib valves V120A/B Normally closed/ fail as is	Failure to open	All design basis events	No safety-related effect since each valve has a redundant flow path through a MOV and a squib valve, actuated by separate divisions, that open to provide recirculation through a parallel branch line. The other containment recirculation line is unaffected.	Valve position indication alarm in MCR and at RSW	
Containment recirculation line squib valves V118A/B Normally closed/ fail as is	Failure to open	All design basis events	No safety-related effect since each valve has a redundant flow path through a check valve and a squib valve, actuated by separate divisions, that independently open to provide recirculation through a parallel branch line. The other containment recirculation line is unaffected.	Valve position indication alarm in MCR and at RSW	
Accumulator fill/ drain line isolation AOVs V232A/B Normally closed/ fail closed	Spurious opening	All design basis events	No safety-related effect since each valve has either a normally closed redundant, series isolation valve or a check valve in each drain flow path, which prevents draining water from the accumulator.	Valve position indication alarm in MCR and at RSW	
CMT fill line isolation AOVs V230A/B Normally closed/ fail closed	Spurious opening	All design basis events	No safety-related effect since each valve has a redundant, series check valve that closes on reverse flow and prevents draining water from the CMT.	Valve position indication alarm in MCR and at RSW	
CMT fill line check valves V231A/B Normally closed	Failure to close on reverse flow	All design basis events	No safety-related effect since each valve has a normally closed redundant, series AOV that prevents draining water from the CMT.	No valve position indication CMT low level indication alarm in MCR and at RSW	

Table 6.3-3 (Sheet 4 of 4)

FAILURE MODE AND EFFECTS ANALYSIS - PASSIVE CORE COOLING SYSTEM ACTIVE COMPONENTS

Component	Failure Mode	Plant Condition	Effect on System Operation	Failure Detection Method	Remarks
ADS Stage 1 to 3 MOVs and Stage 4 squib valves V001A/B, V011A/B, V002A/B, V012A/B, V003A/B, V013A/B, V004A/B/C/D Normally closed/ fail as is	Failure to open on demand	All design basis events	Failure to open blocks reactor coolant system vent flow through the one of two parallel branch lines of the affected ADS valve stage. Failure of a Stage 4 ADS valve is the most limiting single valve failure from the standpoint of ADS performance, based on this stage being the largest valve size. With the failure of ADS path, the ADS vent flow capacity is reduced, but safety analysis has demonstrated that the limiting Stage 4 ADS valve failure still meets design basis reactor coolant system venting requirements.	Valve position indication alarm in MCR and at RSW	
Class 1E direct current and UPS system distribution switchgear division IDSA DS 1 IDSB DS 1 IDSC DS 1 IDSD DS 1	Failure of a dc power source	All design basis events	Failure of a single dc power source from either Division A or Division B is the most limiting dc failure. The limiting PXS components are the IRWST injection/containment recirc. valves and the ADS valves. Failure of either of these dc power sources can prevent actuation of the ADS Stage 1 and Stage 3 MOVs in one group of ADS valves. The other ADS valves are unaffected by this failure. This dc power failure can also cause failure of one (of 4) IRWST injection squib valves and one (of 4) squib recirculation valves. The ADS vent flow and IRWST injection/containment recirculation capacity is reduced, but safety analysis has demonstrated that this limiting valve failure combination still meets design basis reactor coolant system venting/injection requirements.	Valves position indication alarm in MCR and at RSW	For other PXS components, the loss of a Class 1E division either actuates the affected AOVs to a fail-safe position, or does not affect MOVs which are already in appropriate positions

[This page intentionally blank]

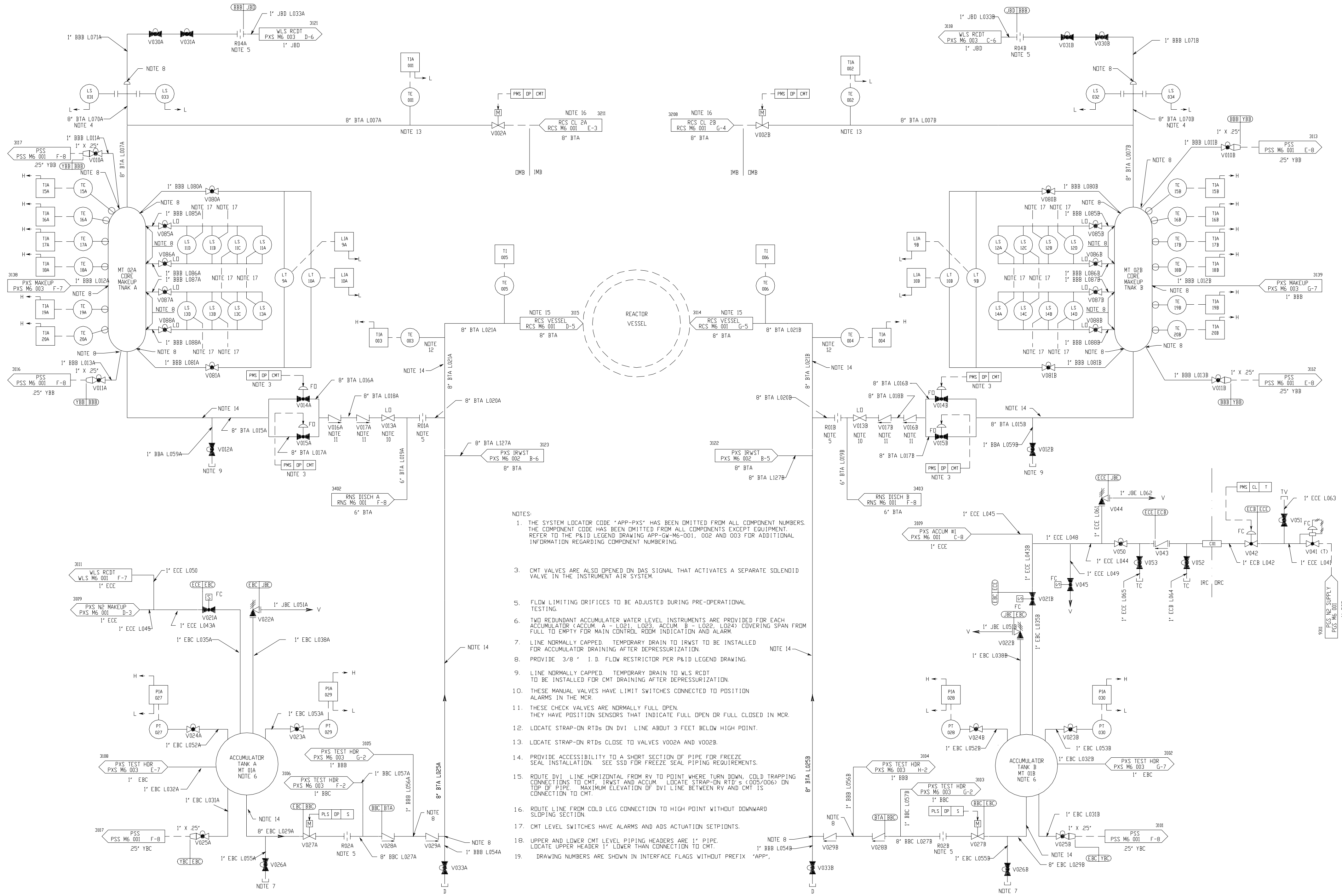


Figure 6.3-1

Passive Core Cooling System
Piping and Instrumentation Diagram (Sheet 1)

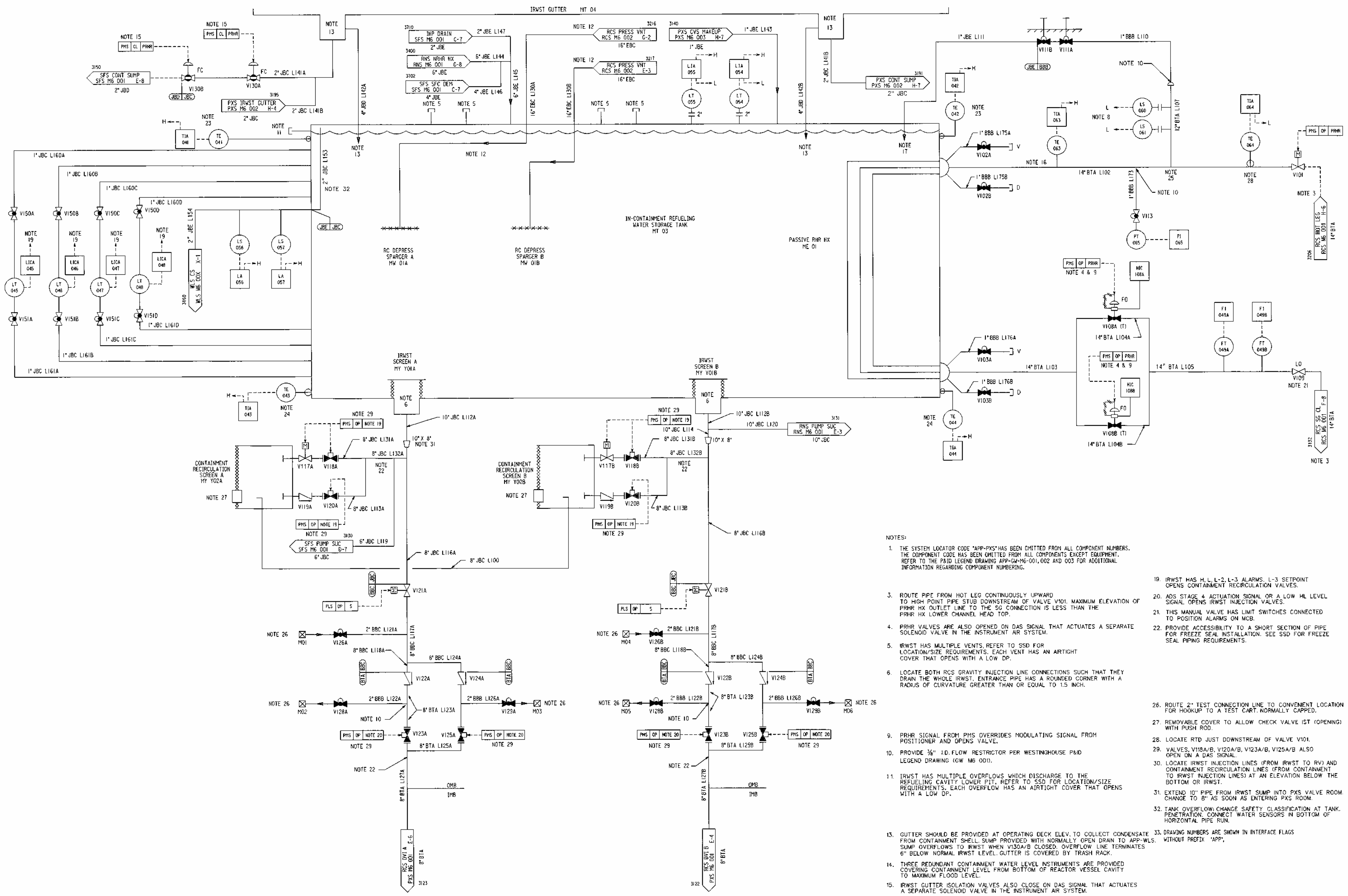
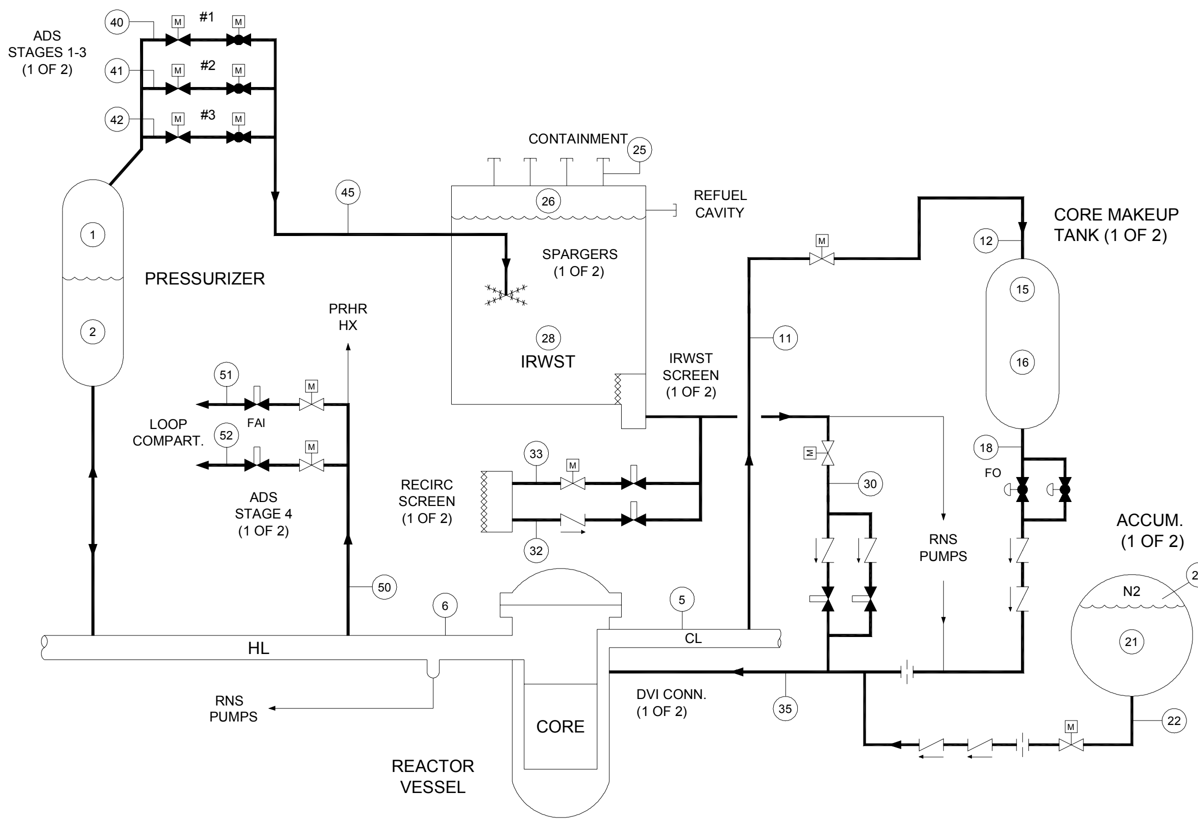


Figure 6.3-2

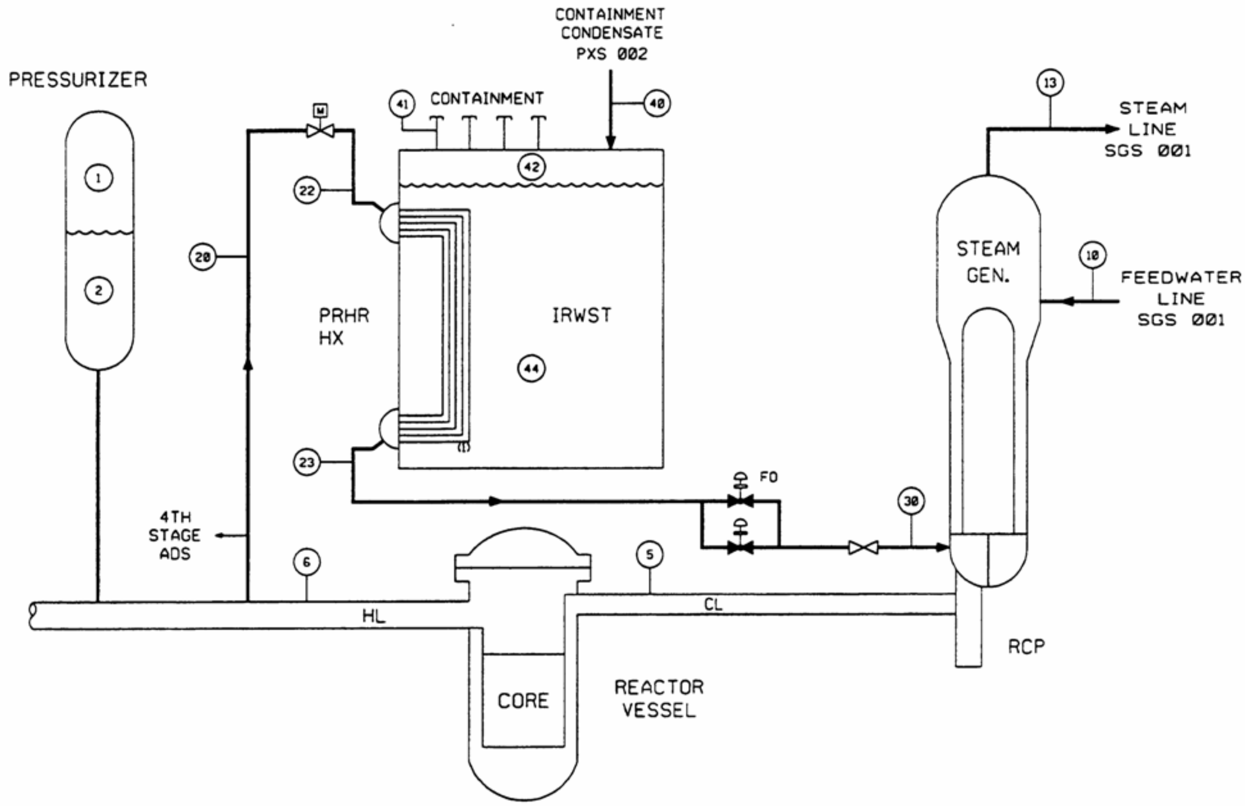
Passive Core Cooling System
Piping and Instrumentation Diagram (Sheet 2)



Inside Reactor Containment

Figure 6.3-3

Passive Safety Injection
(REF) RCS & PXS



Inside Reactor Containment

Figure 6.3-4

Passive Decay Heat Removal
(REF) RCS & PXS

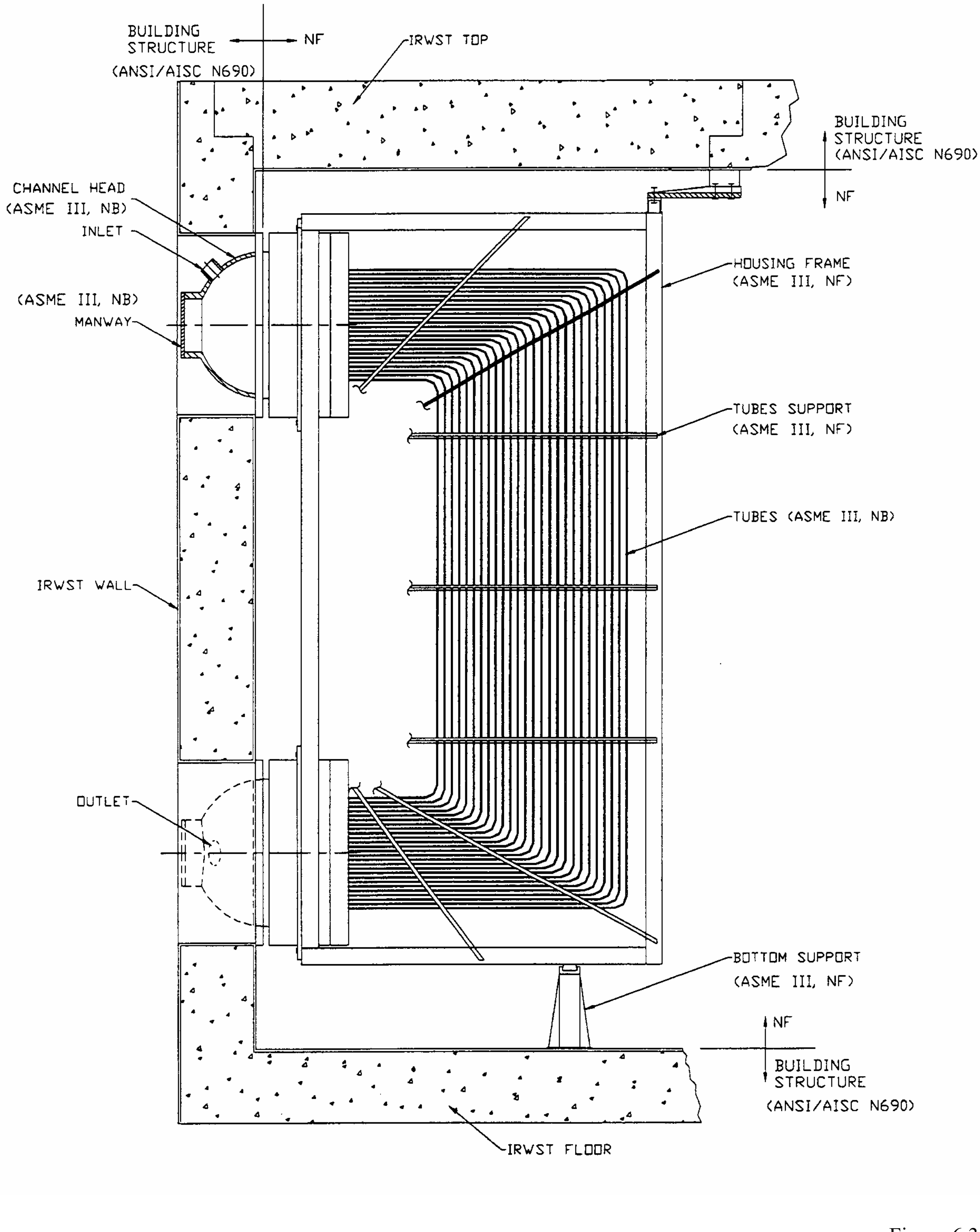


Figure 6.3-5

Passive Heat Removal Heat Exchanger

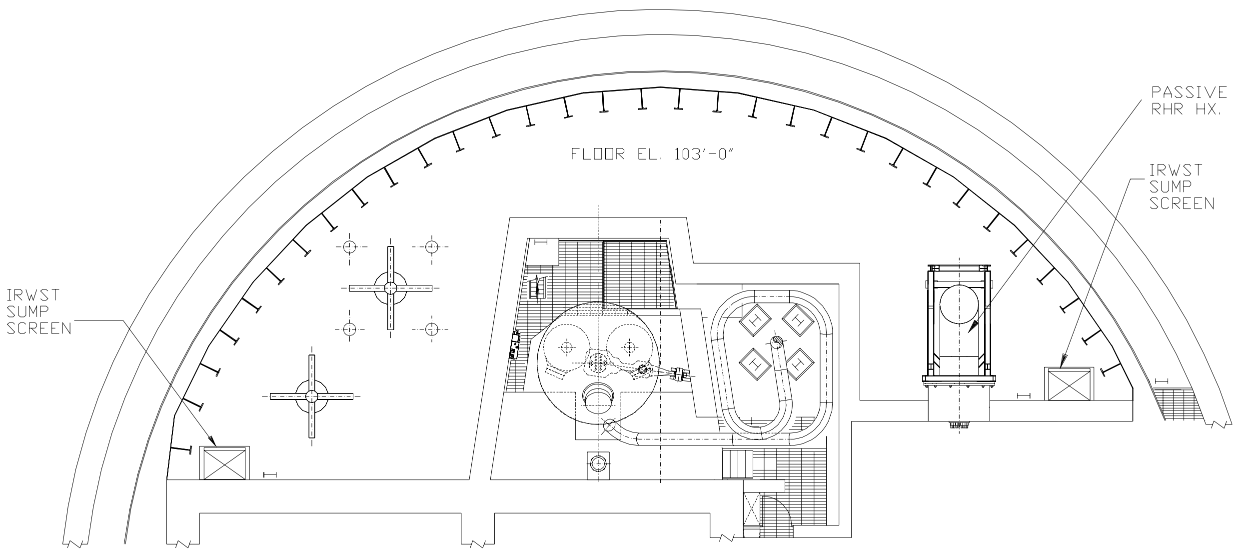


Figure 6.3-6

IRWST Screen Plan Location

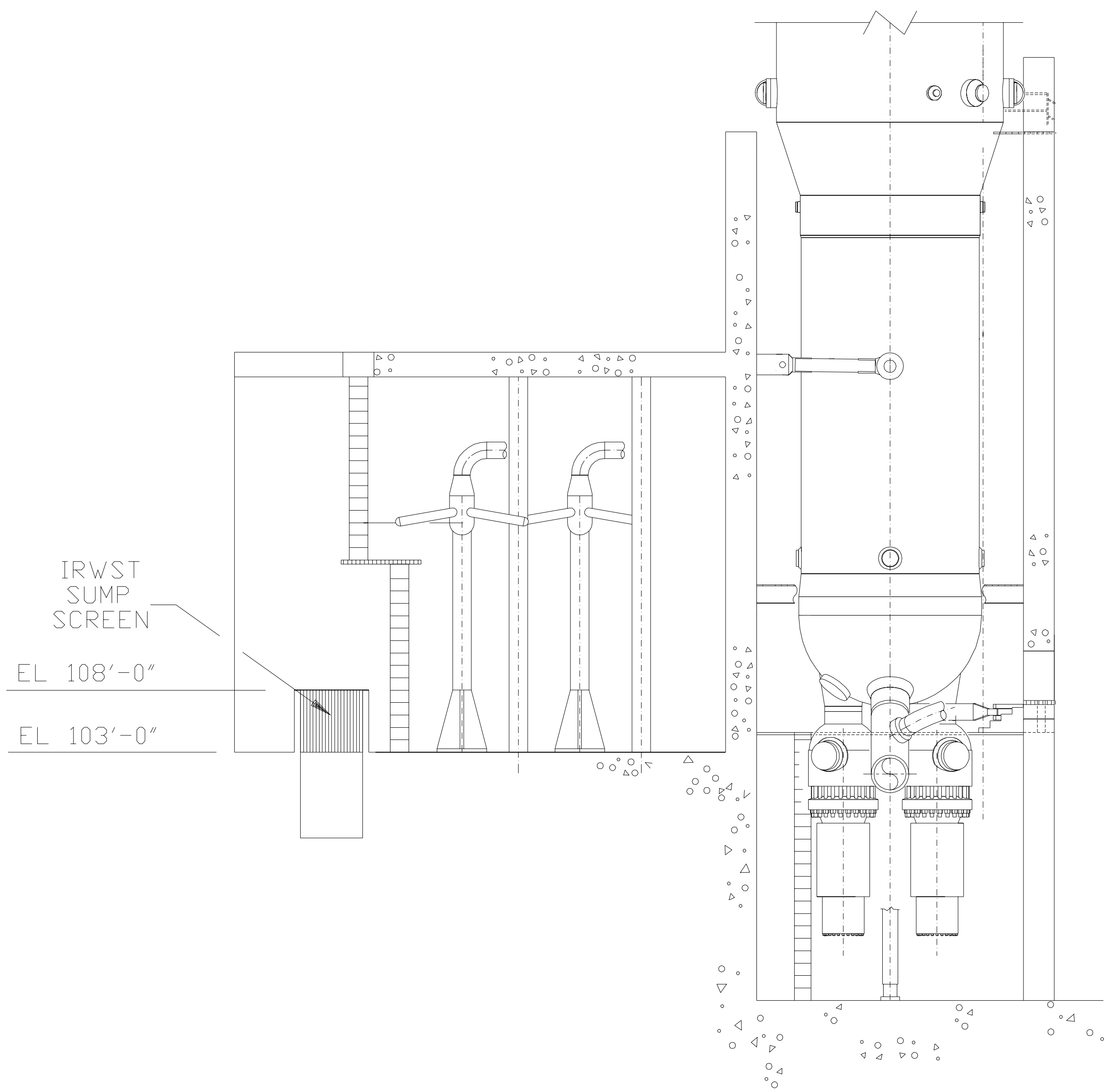


Figure 6.3-7

IRWST Screen Section Location

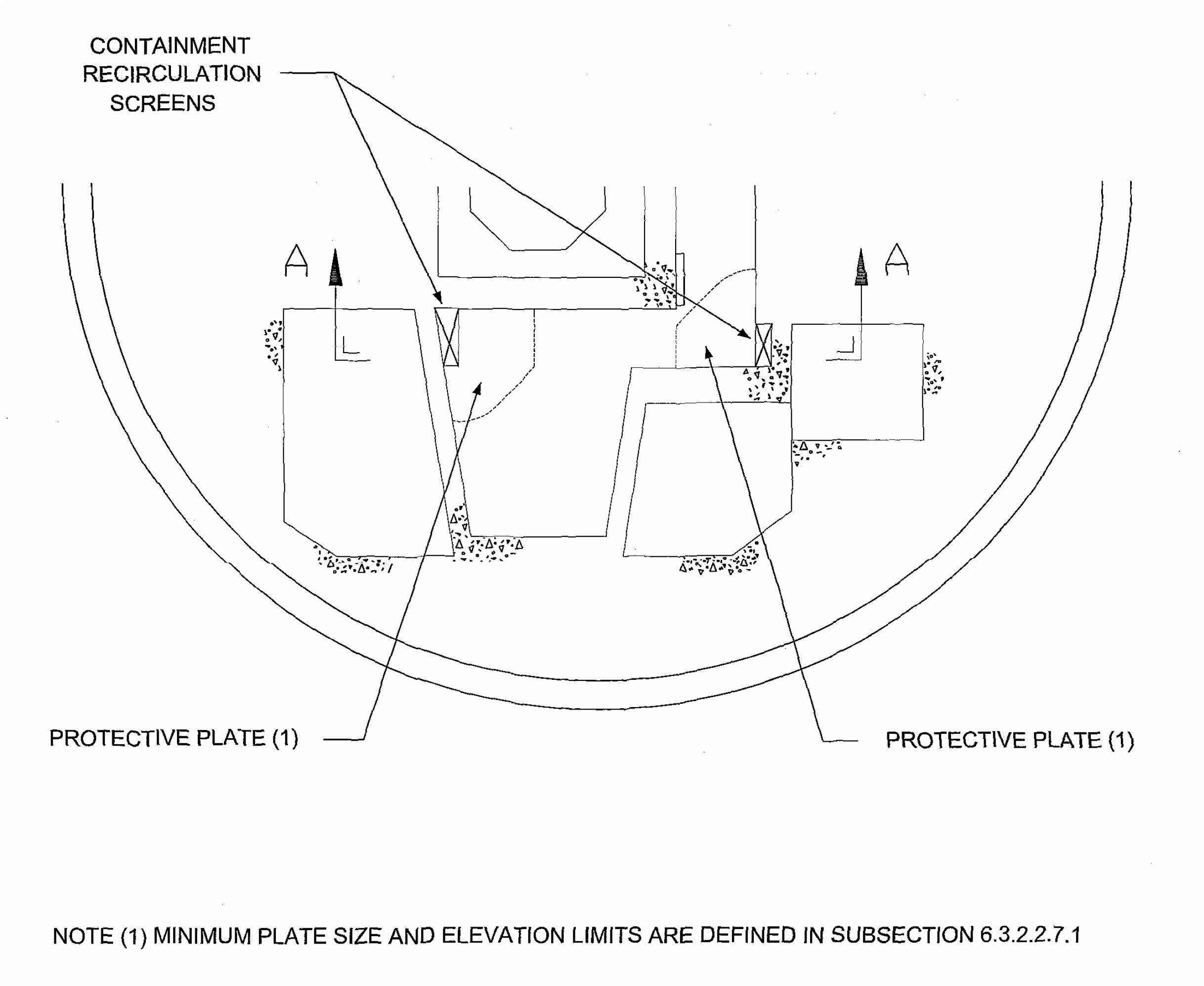


Figure 6.3-8

Containment Recirculation Screen Location Plan

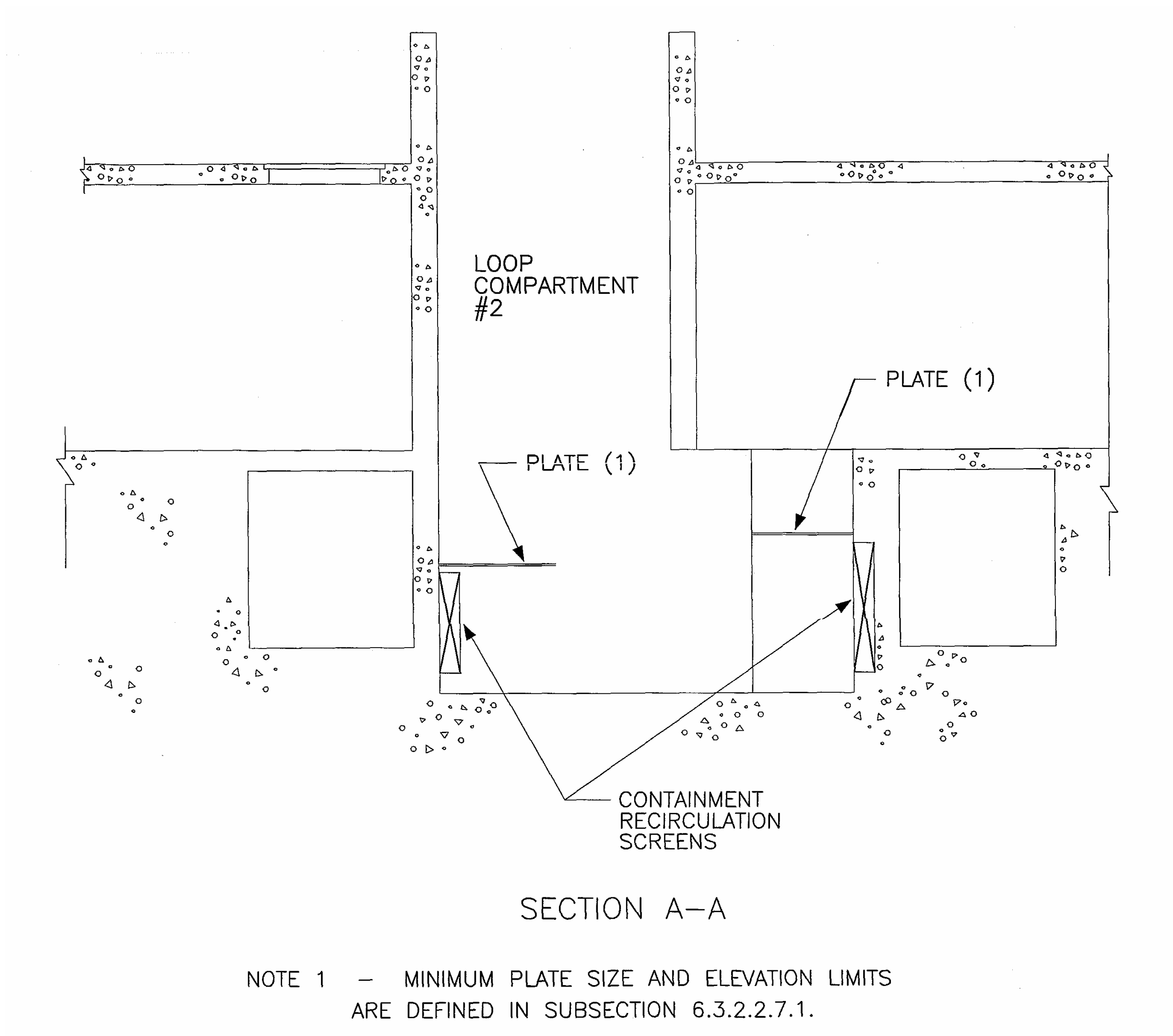


Figure 6.3-9

Containment Recirculation Screen Location Elevation

6.4 Habitability Systems

The habitability systems are a set of individual systems that collectively provide the habitability functions for the plant. The systems that make up the habitability systems are the:

- Nuclear island nonradioactive ventilation system (VBS)
- Main control room emergency habitability system (VES)
- Radiation monitoring system (RMS)
- Plant lighting system (ELS)
- Fire Protection System (FPS)

When a source of ac power is available, the nuclear island nonradioactive ventilation system (VBS) provides normal and abnormal HVAC service to the main control room (MCR), technical support center (TSC), instrumentation and control rooms, dc equipment rooms, battery rooms, and the nuclear island nonradioactive ventilation system equipment room as described in subsection 9.4.1.

If ac power is unavailable for more than 10 minutes or if “high-high” particulate or iodine radioactivity is detected in the main control room supply air duct, which would lead to exceeding General Design Criteria 19 operator dose limits, the protection and safety monitoring system automatically isolates the main control room and operator habitability requirements are then met by the main control room emergency habitability system (VES). The main control room emergency habitability system is capable of providing emergency ventilation and pressurization for the main control room. The main control room emergency habitability system also provides emergency passive heat sinks for the main control room, instrumentation and control rooms, and dc equipment rooms.

Radiation monitoring of the main control room environment is provided by the radiation monitoring system. Smoke detection is provided in the VBS system. Emergency lighting is provided by the plant lighting system. Storage capacity is provided in the main control room for personnel support equipment. Manual hose stations outside the MCR and portable fire extinguishers are provided to fight MCR fires.

6.4.1 Safety Design Basis

The safety design bases discussed here apply only to the portion of the individual system providing the specified function. The range of applicability is discussed in subsection 6.4.4.

6.4.1.1 Main Control Room Design Basis

The habitability systems provide coverage for the main control room pressure boundary as defined in subsection 6.4.2.1. The following discussion summarizes the safety design bases with respect to the main control room:

- The habitability systems are capable of maintaining the main control room environment suitable for prolonged occupancy throughout the duration of the postulated accidents discussed in Chapter 15 that require protection from the release of radioactivity. Refer to

Section 3.1 and subsections 6.4.4 and 15.6.5.3 for a discussion on conformance with General Design Criterion 19 and to Section 1.9 for a discussion on conformance with Generic Issue B-66.

- The main control room is designed to withstand the effects of an SSE and a design-basis tornado.

- A maximum main control room occupancy of up to 11 persons can be accommodated.

- The radiation exposure of main control room personnel throughout the duration of the postulated limiting faults discussed in Chapter 15 does not exceed the limits set by General Design Criterion 19.

- The emergency habitability system maintains CO_2 concentration to less than 0.5 percent for up to 11 main control room occupants.

- The habitability systems provide the capability to detect and protect main control room personnel from external fire, smoke, and airborne radioactivity.

- Automatic actuation of the individual systems that perform a habitability systems function is provided. Smoke detectors, radiation detectors, and associated control equipment are installed at various plant locations as necessary to provide the appropriate operation of the systems.

6.4.1.2 Instrumentation and Control Room/DC Equipment Rooms Design Basis

The habitability systems are also designed to service the instrumentation and control rooms and dc equipment rooms. The habitability systems are capable of maintaining the temperature in the instrumentation and control rooms and dc equipment rooms below the equipment qualification temperature limit throughout the duration of the postulated accidents discussed in Chapter 15, an SSE, or design-basis tornado.

6.4.2 System Description

Only the main control room emergency habitability system is discussed in this subsection. The remaining systems are described only as necessary to define their functions in meeting the safety-related design bases of the habitability systems. Descriptions of the nuclear island nonradioactive ventilation system, fire protection system, plant lighting system, and radiation monitoring system are found in subsections 9.4.1, 9.5.1, 9.5.3, and Section 11.5, respectively.

6.4.2.1 Definition of the Main Control Room Pressure Boundary

The main control room pressure boundary is located on elevation 117′-6″ in the auxiliary building, on the nuclear island. As shown in Figure 6.4-1, the pressure boundary encompasses the main control area, tagging room, operator area, shift supervisor’s office, clerk’s office, kitchen, and toilet facilities. The pressure boundary is represented by the line around the periphery of the

boundary in the figure. The stairwell leading down to elevation 100′ is specifically excluded from the boundary.

The areas, equipment, and materials to which the main control room operator requires access during a postulated accident are shown in Figure 6.4-1. This figure is a subset of Figure 1.2-8. Areas adjacent to the main control room are shown in Figures 1.2-25 and 1.2-31. The layout, size, and ergonomics of the operator workstations and wall panel information system depicted in Figure 6.4-1 do not reflect the results of the design process described in Chapter 18. The actual size, shape, ergonomics, and layout of the operator workstations and wall panel information system is an output of the design process in Chapter 18.

6.4.2.2 General Description

The main control room emergency habitability system air storage tanks are sized to deliver the required air flow to the main control room to meet the ventilation and pressurization requirements for 72 hours based on the performance requirements of subsection 6.4.1.1. Normal system makeup is provided by a connection to the breathable quality air compressor in the compressed and instrument air system (CAS). See subsection 9.3.1 for a description of the CAS. A connection for refilling operation is provided in the CAS.

The function of providing passive heat sinks for the main control room, instrumentation and control rooms, and dc equipment rooms is part of the main control room emergency habitability system. The heat sinks for each room are designed to limit the temperature rise inside each room during the 72-hour period following a loss of nuclear island nonradioactive ventilation system operation. The heat sinks consist primarily of the thermal mass of the concrete that makes up the ceilings and walls of these rooms.

To enhance the heat-absorbing capability of the ceilings, a metal form is attached to the interior surface of the concrete at selected locations. Metallic plates are attached perpendicular to the form. These plates extend into the room and act as thermal fins to enhance the heat transfer from the room air to the concrete. The specifics of the fin construction for the main control room and I&C room ceilings are described in subsection 3.8.4.1.2.

The normal operating temperatures in the main control room, instrumentation and control rooms, dc equipment rooms, and adjacent rooms are kept within a specified range by the nuclear island nonradioactive ventilation system in order to maintain a design basis initial heat sink capacity of each room. See subsection 9.4.1 for a description of the nuclear island nonradioactive ventilation system.

In the unlikely event that power to the nuclear island nonradioactive ventilation system is unavailable for more than 72 hours, MCR habitability is maintained by operating one of the two MCR ancillary fans to supply outside air to the MCR. See subsection 9.4.1 for a description of this cooling mode of operation. Doors and ducts may be opened to provide a supply pathway and an exhaust pathway. Likewise, outside air is supplied to division B and C instrumentation and control rooms in order to maintain the ambient temperature below the qualification temperature of the equipment.

The main control room emergency habitability system piping and instrumentation diagram is shown in Figure 6.4-2.

6.4.2.3 Component Description

The main control room emergency habitability system compressed air supply contains a set of storage tanks connected to a main and an alternate air delivery line. Components common to both lines include a manual isolation valve, a pressure regulating valve, and a flow metering orifice. Single active failure protection is provided by the use of redundant, remotely operated isolation valves, which are located within the MCR pressure boundary. In the event of insufficient or excessive flow in the main delivery line, the main delivery line is isolated and the alternate delivery line is manually actuated. The alternate delivery line contains the same components as the main delivery line with the exception of the remotely operated isolation valves, and thus is capable of supplying compressed air to the MCR pressure boundary at the required air flowrate. The VES piping and penetrations for the MCR envelope are designated as equipment Class C. Additional details on Class C designation are provided in subsection 3.2.2.5. The classification of VES components is provided in Table 3.2-3, as appropriate.

- Emergency Air Storage Tanks

  There are a total of 32 air storage tanks. The air storage tanks are constructed of forged, seamless pipe, with no welds, and conform to Section VIII and Appendix 22 of the ASME Code. The design pressure of the air storage tanks is 4000 psi. The storage tanks collectively contain a minimum storage capacity of 314,132 scf of air at a minimum pressure of 3400 psig.

- Pressure Regulating Valve

  Each compressed air supply line contains a pressure regulating valve located downstream of the common header. The pressure at the outlet of the valve is controlled via a self contained pressure control operator. The downstream pressure is set to approximately 100 psig so that the flow rate can be controlled by an orifice downstream of the valve.

- Flow Metering Orifice

  The flow rate of air delivered to the main control room pressure boundary is limited by an orifice located downstream of the pressure regulating valve. The orifice is sized to provide the required air flowrate to the main control room pressure boundary, with an upstream pressure of approximately 100 psig.

- Air Delivery Main Isolation Valve

  The pressure boundary of the compressed air storage tanks is maintained by normally closed remotely operated isolation valves in the main supply line. These valves are located within MCR pressure boundary downstream of the pressure regulating valve and automatically initiate air flow upon receipt of a signal to open (see subsection 6.4.3.2).

- Pressure Relief Isolation Valve

  To limit the pressure increase within the main control room, isolation valves are provided, one in each of redundant flowpaths, which open on a time delay after receipt of an emergency habitability system actuation signal. The valves provide a leak tight seal to protect the integrity of the main control room pressure boundary during normal operation, and are normally closed to prevent interference with the operation of the nonradioactive ventilation system.

- Main Air Flowpath Isolation Valve

  The main air flowpath contains a normally open, manually operated valve located within the MCR pressure boundary, upstream of the remotely operated air delivery main isolation valves. The valve is provided as a means of isolating and preserving the air storage tank's contents in the event of a pressure regulating valve malfunction.

- Air Delivery Alternate Isolation Valve

  The alternate air delivery flowpath contains a normally closed, manually operated valve, located within the MCR pressure boundary. The valve is provided as a means of manually activating the alternate air delivery flowpath in the event the main air delivery flowpath is inoperable.

- Pressure Relief Damper

  Pressure relief dampers are located downstream of the butterfly isolation valves, and are set to open on a differential pressure of at least 1/8-inch water gauge with respect to the surrounding areas. The differential pressure between the control room and the relief damper exhaust location is monitored to ensure that a positive pressure is maintained in the control room with respect to its surroundings.

- Control Room Access Doors

  Two sets of doors, with a vestibule between that acts as an airlock, are provided at the access to the main control room.

- Breathing Apparatus

  Self-contained portable breathing equipment with air bottles is stored inside the main control room pressure boundary. The amount of stored air is sufficient to provide a 6-hour supply of breathable air for up to 11 main control room occupants. This is backup protection to the permanently installed habitability systems.

6.4.2.4 Leaktightness

The main control room pressure boundary is designed for low leakage. It consists of cast-in-place reinforced concrete walls and slabs, and is constructed to minimize leakage through construction

joints and penetrations. The following features are applied as needed in order to achieve this objective:

- The outside surface of penetrations sleeves in contact with concrete are sealed with epoxy crack sealer. The piping and electrical cable penetrations are sealed with qualified pressure-resistant material compatible with penetration materials and/or cable jacketing.

- The interior or exterior surfaces of the main control room envelope (walls, floor, and ceiling) are coated with low permeability paint/epoxy sealant.

- Inside surfaces of penetrations and sleeves in contact with commodities (i.e., pipes and conduits, etc.) are sealed. Main control room pressure boundary HVAC isolation valves are qualified to shut tight against control room pressure.

- Penetration sealing materials are designed to withstand at least 1/4-inch water gauge pressure differential in an air pressure barrier. Penetration sealing material is gypsum cement or equivalent.

The piping, conduits, and electrical cable trays penetrating through any combination of main control room pressure boundary are sealed with seal assembly compatible with the materials of penetration commodities. Penetration sealing materials are selected to meet barrier design requirements and are designed to withstand specific area environmental design requirements and remain functional and undamaged during and following an SSE. No silicone sealant or other patching material is used on VES piping, valves, dampers, or penetrations forming the MCR pressure boundary. There are no adverse environmental effects on the MCR sealant materials resulting from postulated spent fuel pool boiling events.

The main control room pressure boundary main entrance is designed with an airlock-type double-door vestibule. The emergency exit door (stairs to elevation 100′) is normally closed, and remains closed under design basis source term conditions.

When the main control room pressure boundary is isolated in an accident situation, there is no direct communication with the outside atmosphere, nor is there communication with the normal ventilation system. Leakage from the main control room pressure boundary is the result of an internal pressure of at least 1/8-inch water gauge provided by emergency habitability system operation.

The exfiltration and infiltration analysis for nuclear island nonradioactive ventilation system operation is discussed in subsection 9.4.1.

6.4.2.5 Interaction with Other Zones and Pressurized Equipment

The main control room emergency habitability system is a self-contained system. There is no interaction between other zones and pressurized equipment.

For a discussion of the nuclear island nonradioactive ventilation system, refer to subsection 9.4.1.

6.4.2.6 Shielding Design

The design basis loss-of-coolant accident (LOCA) dictates the shielding requirements for the main control room. Main control room shielding design bases are discussed in Section 12.3. Descriptions of the design basis LOCA source terms, main control room shielding parameters, and evaluation of doses to main control room personnel are presented in Section 15.6.

The main control room and its location in the plant are shown in Figure 12.3-1.

6.4.3 System Operation

This subsection discusses the operation of the main control room emergency habitability system.

6.4.3.1 Normal Mode

The main control room emergency habitability system is not required to operate during normal conditions. The nuclear island nonradioactive ventilation system maintains the air temperature of a number of rooms within a predetermined temperature range. The rooms with this requirement include the rooms with a main control room emergency habitability system passive heat sink design and their adjacent rooms.

6.4.3.2 Emergency Mode

Operation of the main control room emergency habitability system is automatically initiated by either of the following conditions:

- “High-high” particulate or iodine radioactivity in the main control room supply air duct
- Loss of ac power for more than 10 minutes

Operation can also be initiated by manual actuation.

If radiation levels in the main control room supply air duct exceed the “high-high” setpoint, the nuclear island nonradioactive ventilation system is isolated from the main control room pressure boundary by automatic closure of the isolation devices located in the nuclear island nonradioactive ventilation system ductwork. At the same time, the main control room emergency habitability system begins to deliver air from the emergency air storage tanks to the main control room by automatically opening the isolation valves located in the supply line. The relief damper isolation valves also open allowing the pressure relief dampers to function.

After the main control room emergency habitability system isolation valves are opened, the air supply pressure is regulated by a self-contained regulating valve. This valve maintains a constant downstream pressure regardless of the upstream pressure. A constant air flow rate is maintained by the flow metering orifice downstream of the pressure regulating valve. This flow rate is sufficient to maintain the main control room pressure boundary at least 1/8-inch water gauge positive differential pressure with respect to the surroundings. The main control room emergency habitability system air flow rate is also sufficient to maintain the carbon dioxide levels below 0.5 percent concentration for 11 occupants and to maintain air quality within the guidelines of Table 1 and Appendix C, Table C-1, of Reference 1.

The emergency air storage tanks are sized to provide the required air flow to the main control room pressure boundary for 72 hours. After 72 hours, the main control room is cooled by drawing in outside air and circulating it through the room, as discussed in subsection 6.4.2.2.

The temperature and humidity in the main control room pressure boundary following a loss of the nuclear island nonradioactive ventilation system remain within limits for reliable human performance (References 2 and 3) over a 72-hour period. The initial values of temperature/relative humidity in the MCR are 75°F/60 percent. At 3 hours, when the non-1E battery heat loads are exhausted, the conditions are 87.2°F/41 percent. At 24 hours, when the 24 hour battery heat loads are terminated, the conditions are 84.4°F/45 percent. At 72 hours, the conditions are 85.8°F/ 39 percent.

Sufficient thermal mass is provided in the walls and ceiling of the main control room to absorb the heat generated by the equipment, lights, and occupants. The temperature in the instrumentation and control rooms and dc equipment rooms following a loss of the nuclear island nonradioactive ventilation system remains below acceptable limits as discussed in subsection 6.4.4. As in the main control room, sufficient thermal mass is provided surrounding these rooms to absorb the heat generated by the equipment. After 72 hours, the instrumentation and control rooms will be cooled by drawing in outside air and circulating it through the room, as discussed in subsection 6.4.2.2.

In the event of a loss of ac power, the nuclear island nonradioactive ventilation system isolation valves automatically close and the main control room emergency habitability system isolation valves automatically open. These actions protect the main control room occupants from a potential radiation release. In instances in which there is no radiological source term present, the compressed air storage tanks are refilled via a connection to the breathable quality air compressor in the compressed and instrument air system (CAS). The compressed air storage tanks can also be refilled from portable supplies by an installed connection in the CAS.

6.4.4 System Safety Evaluation

Doses to main control room personnel were calculated for both the situation in which the emergency habitability system (VES) is relied upon to limit the amount of activity the personnel are exposed to and the situation in which the nuclear island nonradioactive ventilation system (VBS) is available to pressurize the main control room with filtered air and provide recirculation cleanup. Doses were calculated for the following accidents:

	VES Operating	VBS Operating
Large Break LOCA	4.8 rem TEDE	4.5 rem TEDE
Fuel Handling Accident	4.5 rem TEDE	2.4 rem TEDE
Steam Generator Tube Rupture		
(Pre-existing iodine spike)	4.8 rem TEDE	3.4 rem TEDE
(Accident-initiated iodine spike)	2.1 rem TEDE	1.8 rem TEDE
Steam Line Break		
(Pre-existing iodine spike)	3.4 rem TEDE	2.1 rem TEDE
(Accident-initiated iodine spike)	3.7 rem TEDE	4.9 rem TEDE
Rod Ejection Accident	2.1 rem TEDE	1.3 rem TEDE

	VES Operating	VBS Operating
Locked Rotor Accident		
(Accident without feedwater available)	0.9 rem TEDE	0.9 rem TEDE
(Accident with feedwater available)	0.7 rem TEDE	1.6 rem TEDE
Small Line Break Outside Containment	1.2 rem TEDE	0.3 rem TEDE

For all events the dose are within the dose acceptance limit of 5.0 rem TEDE. The details of analysis assumptions for modeling the doses to the main control room personnel are delineated in the LOCA dose analysis discussion in subsection 15.6.5.3.

No radioactive materials are stored or transported near the main control room pressure boundary.

As discussed and evaluated in subsection 9.5.1, the use of noncombustible construction and heat and flame resistant materials throughout the plant reduces the likelihood of fire and consequential impact on the main control room atmosphere. Operation of the nuclear island nonradioactive ventilation system in the event of a fire is discussed in subsection 9.4.1.

The exhaust stacks of the onsite standby power diesel generators are located in excess of 150 feet away from the fresh air intakes of the main control room. The onsite standby power system fuel oil storage tanks are located in excess of 300 feet from the main control room fresh air intakes. These separation distances reduce the possibility that combustion fumes or smoke from an oil fire would be drawn into the main control room.

The protection of the operators in the main control room from offsite toxic gas releases is discussed in Section 2.2. The sources of onsite chemicals are described in Table 6.4-1, and their locations are shown on Figure 1.2-2. Analysis of these sources is in accordance with Regulatory Guide 1.78 (Reference 5) and the methodology in NUREG-0570, "Toxic Vapor Concentrations in the Control Room Following a Postulated Accidental Release" (Reference 6), and the analysis shows that these sources do not represent a toxic hazard to control room personnel.

A supply of protective clothing, respirators, and self-contained breathing apparatus adequate for 11 persons is stored within the main control room pressure boundary.

The main control room emergency habitability system components discussed in subsection 6.4.2.3 are arranged as shown in Figure 6.4-2. The location of components and piping within the main control room pressure boundary provides the required supply of compressed air to the main control room pressure boundary, as shown in Figure 6.4-1.

During emergency operation, the main control room emergency habitability system passive heat sinks are designed to limit the temperature inside the main control room to remain within limits for reliable human performance (References 2 and 3) over 72 hours. The passive heat sinks limit the air temperature inside the instrumentation and control rooms to 120°F and dc equipment rooms to 120°F. The walls and ceilings that act as the passive heat sinks contain sufficient thermal mass to accommodate the heat sources from equipment, personnel, and lighting for 72 hours.

The main control room emergency habitability system nominally provides 65 scfm of ventilation air to the main control room from the compressed air storage tanks. Sixty scfm of ventilation flow is sufficient to pressurize the control room to at least positive 1/8-inch water gauge differential

pressure with respect to the surrounding areas in addition to limiting the carbon dioxide concentration below one-half percent by volume for a maximum occupancy of 11 persons and maintaining air quality within the guidelines of Table 1 and Appendix C, Table C-1, of Reference 1.

Automatic transfer of habitability system functions from the main control room/technical support center HVAC subsystem of the nuclear island nonradioactive ventilation system to the main control room emergency habitability system is initiated by either the following conditions:

- "High-high" particulate or iodine radioactivity in MCR air supply duct
- Loss of ac power for more than 10 minutes

The airborne fission product source term in the reactor containment following the postulated LOCA is assumed to leak from the containment and airborne fission products are assumed to result from spent fuel pool steaming. The concentration of radioactivity, which is assumed to surround the main control room, after the postulated accident, is evaluated as a function of the fission product decay constants, the containment leak rate, and the meteorological conditions assumed. The assessment of the amount of radioactivity within the main control room takes into consideration the radiological decay of fission products and the infiltration/exfiltration rates to and from the main control room pressure boundary.

A single active failure of a component of the main control room emergency habitability system or nuclear island nonradioactive ventilation system does not impair the capability of the systems to accomplish their intended functions. The Class 1E components of the main control room emergency habitability system are connected to independent Class 1E power supplies. Both the main control room emergency habitability system and the portions of the nuclear island nonradioactive ventilation system which isolates the main control room are designed to remain functional during an SSE or design-basis tornado.

6.4.5 Inservice Inspection/Inservice Testing

A program of preoperational and postoperational testing requirements is implemented to confirm initial and continued system capability. The VES system is tested and inspected at appropriate intervals, as defined by the technical specifications. Emphasis is placed on tests and inspections of the safety-related portions of the habitability systems.

6.4.5.1 Preoperational Inspection and Testing

Preoperational testing of the main control room emergency habitability system is performed to verify that the air flow rate of 65 ± 5 scfm is sufficient to maintain pressurization of the main control room envelope of at least 1/8-inch water gauge with respect to the adjacent areas. The positive pressure within the main control room is confirmed via the differential pressure transmitters within the control room. The installed flow meters are utilized to verify the system flow rates. The pressurization of the control room limits the ingress of radioactivity to maintain operator dose limits below regulatory limits. Air quality within the MCR environment is confirmed to be within the guidelines of Table 1 and Appendix C, Table C-1, of Reference 1 by analyzing air samples taken during the pressurization test.

The storage capacity of the compressed air storage tanks is verified to be in excess of 314,132 scf of compressed air at a minimum pressure of 3400 psig. This amount of compressed air will assure 72 hours of air supply to the main control room.

An inspection will verify that the heat loads within the rooms identified in Table 6.4-3 are less than the specified values.

Preoperational testing of the main control room isolation valves in the nuclear island nonradioactive ventilation system is performed to verify the leaktightness of the valves.

Preoperational testing for main control room inleakage during VES operation will be conducted in accordance with ASTM E741 (Reference 4).

Testing and inspection of the radiation monitors is discussed in Section 11.5. The other tests noted above are discussed in Chapter 14.

6.4.5.2 Inservice Testing

Inservice testing of the main control room emergency habitability system and nuclear island nonradioactive ventilation system is conducted in accordance with the surveillance requirements specified in the technical specifications in Chapter 16.

Leaktightness testing of the main control room pressure boundary is conducted in accordance with the frequency specified in the technical specifications.

6.4.5.3 Air Quality Testing

Connections are provided for sampling the air supplied from the compressed and instrument air system and for periodic sampling of the air stored in the storage tanks. Air samples of the compressed air storage tanks are taken quarterly and analyzed for acceptable air quality within the guidelines of Table 1 and Appendix C, Table C-1, of Reference 1.

6.4.5.4 Air Inleakage Testing

Testing for main control room inleakage during VES operation will be conducted in accordance with ASTM E741 (Reference 4).

6.4.6 Instrumentation Requirements

The indications in the main control room used to monitor the main control room emergency habitability system and nuclear island nonradioactive ventilation system are listed in Table 6.4-2.

Instrumentation required for actuation of the main control room emergency habitability system and nuclear island nonradioactive ventilation system are discussed in subsection 7.3.1.

Details of the radiation monitors used to provide the main control room indication of actuation of the nuclear island nonradioactive ventilation system supplemental filtration mode of operation and actuation of main control room emergency habitability system operation are given in Section 11.5.

A description of initiating circuits, logic, periodic testing requirements, and redundancy of instrumentation relating to the habitability systems is provided in Section 7.3.

6.4.7 Combined License Information

Combined License applicants referencing the AP1000 certified design are responsible for the amount and location of possible sources of toxic chemicals in or near the plant and for seismic Category I Class 1E toxic gas monitoring, as required. Regulatory Guide 1.78 (Reference 5) addresses control room protection for toxic chemicals and evaluation of offsite toxic releases (including the potential for toxic releases beyond 72 hours) in order to meet the requirements of TMI Action Plan Item III.D.3.4 and GDC 19.

Combined License applicants referencing the AP1000 certified design are responsible for verifying that procedures and training for control room habitability are consistent with the intent of Generic Issue 83 (see Section 1.9).

The Combined License applicant will provide the testing frequency for the main control room inleakage test discussed in subsection 6.4.5.4.

6.4.8 References

1. “Ventilation for Acceptable Indoor Air Quality,” ASHRAE Standard 62 - 1989.

2. “Human Engineering Design Guidelines,” MIL-HDBK-759C, 31 July 1995.

3. “Human Engineering,” MIL-STD-1472E, 31 October 1996.

4. “Standard Test Methods for Determining Air Change in a Single Zone by Means of a Tracer Gas Dilution,” ASTM E741, 2000.

5. “Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release,” Regulatory Guide 1.78, Revision 1, December 2001.

6. NUREG-0570, “Toxic Vapor Concentrations in the Control Room Following a Postulated Accidental Release,” June 1979.

Table 6.4-1

ONSITE CHEMICALS

Material	State	Location
Hydrogen	Gas	Gas storage
Nitrogen	Liquid	Turbine bldg.
CO_2	Liquid	Turbine bldg.
Oxygen Scavenger	Liquid	Turbine bldg.
pH Addition	Liquid	Turbine bldg.
Sulfuric Acid	Liquid	Turbine bldg.
Sodium Hydroxide	Liquid	Turbine bldg.
Dispersant[(a)]	Liquid	Turbine bldg.
Fuel Oil	Liquid	DG fuel oil storage tank/DG bldg./Turbine bldg./ Annex bldg.
Corrosion Inhibitor	Liquid	Turbine bldg.
Scale Inhibitor	Liquid	Turbine bldg.
Biocide/Disinfectant	Liquid	Turbine bldg.
Algicide	Liquid	Turbine bldg.

Note:
(a) Site-specific, by Combined License applicant

Table 6.4-2

MAIN CONTROL ROOM HABITABILITY INDICATIONS AND ALARMS

VES emergency air storage tank pressure (indication and low and low-low alarms)
VES MCR pressure boundary differential pressure (indication and high and low alarms)
VES air delivery line flowrate (indication and high and low alarms)
VBS main control room supply air radiation level (high-high alarms)
VBS outside air intake smoke level (high alarm)
VBS isolation valve position
VBS MCR pressure boundary differential pressure

Note:
KEY: VES = Main control room emergency habitability system
VBS = Nuclear island nonradioactive ventilation system
MCR = Main control room

Table 6.4-3

LOSS OF AC POWER HEAT LOAD LIMITS

Room Name	Room Numbers	Heat Load 0 to 24 Hours (Btu/sec)	Heat Load 24 to 72 Hours (Btu/sec)
MCR Envelope	12401	12.823 (Hour 0 through 3) 5.133 (Hour 4 through 24)	3.928
I&C Rooms	12301, 12305	8.854	0
I&C Rooms	12302, 12304	13.07	4.22
dc Equipment Rooms	12201, 12205	3.792 (Hour 0 through 1) 2.465 (Hour 2 through 24)	0
dc Equipment Rooms	12203, 12207	5.84 (Hour 0 through 1) 4.51 (Hour 2 through 24)	2.05

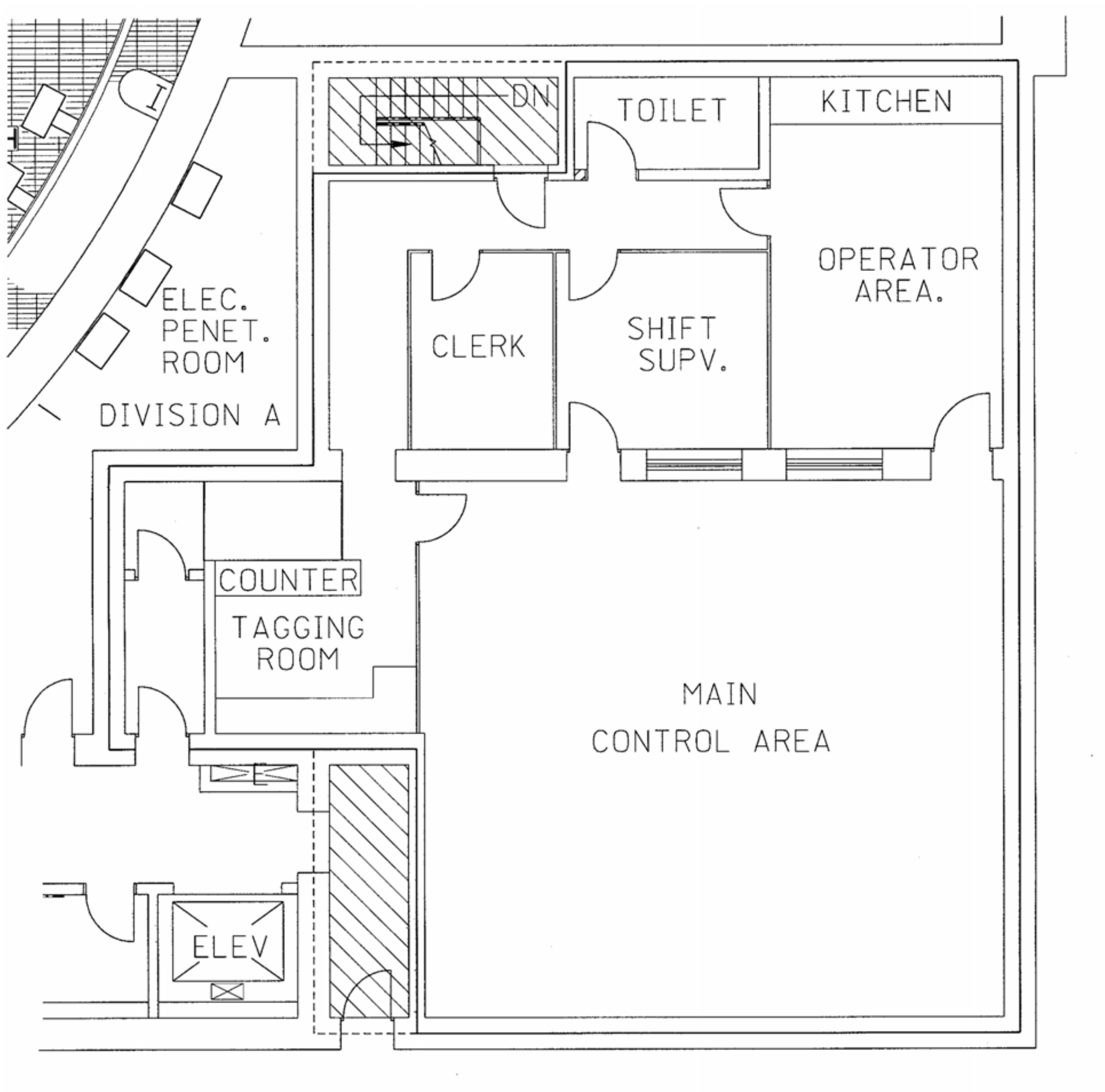


Figure 6.4-1

Main Control Room Envelope

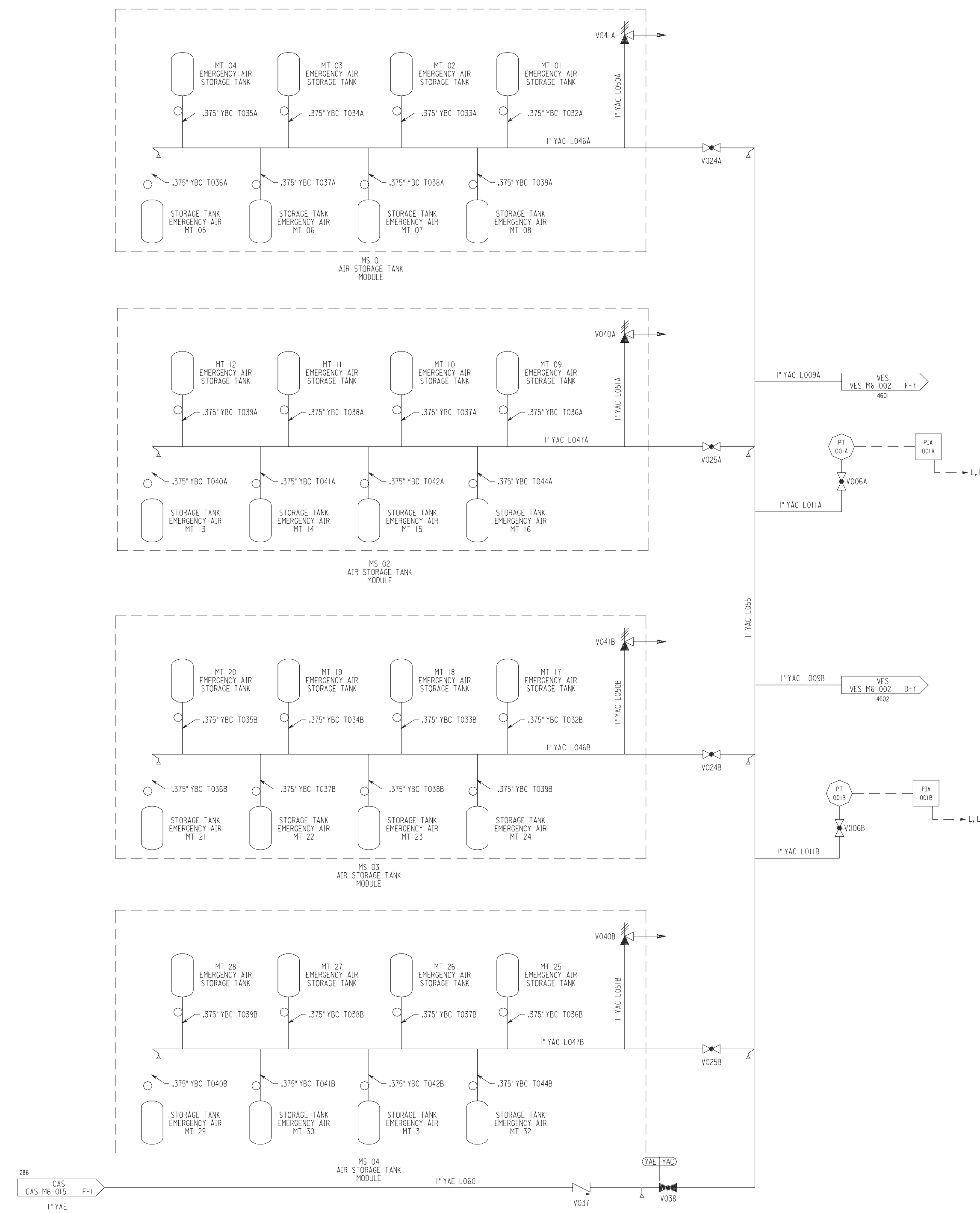
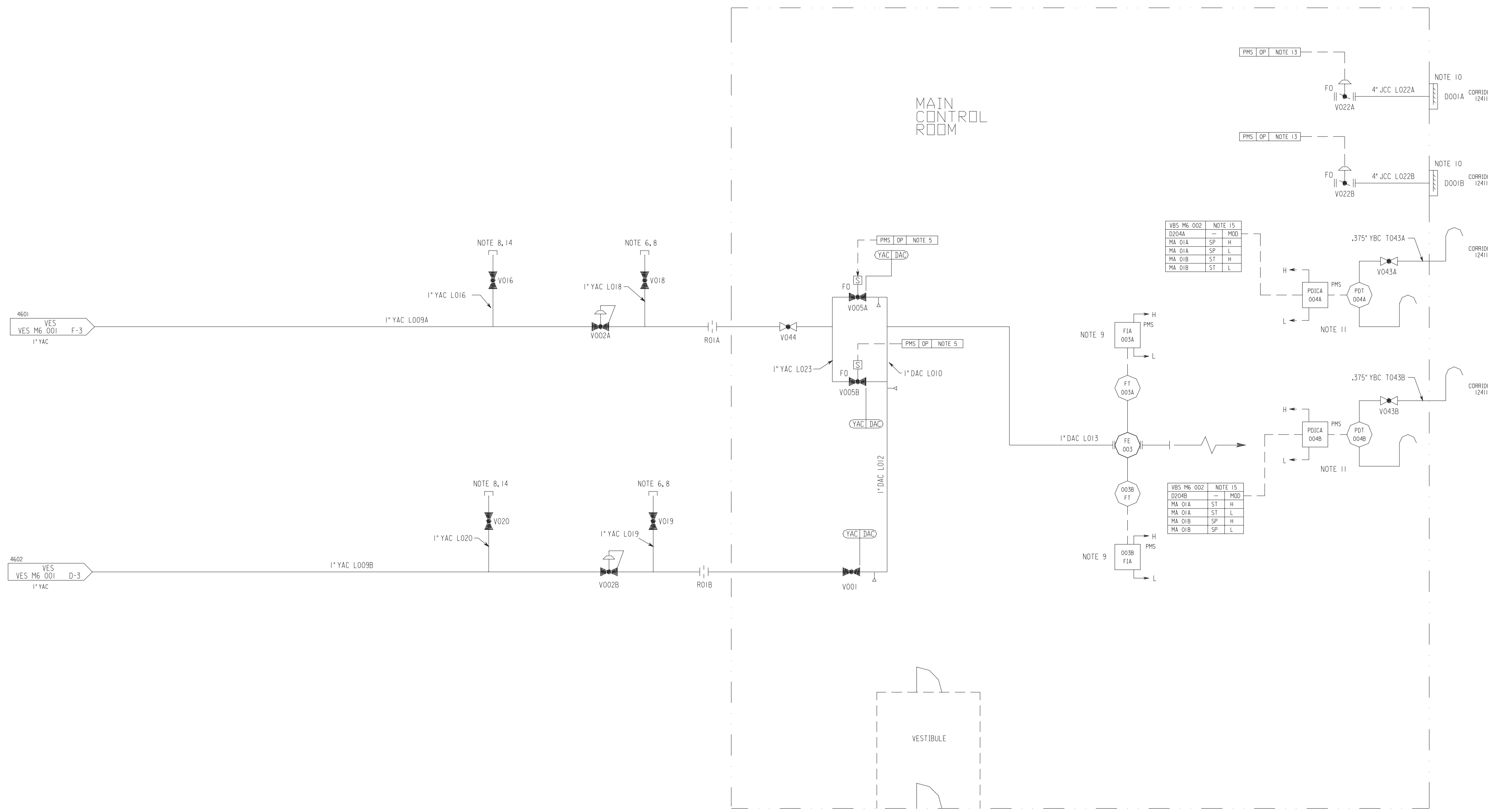


Figure 6.4-2 (Sheet 1 of 2)

Main Control Room Habitability System Piping and Instrumentation Diagram



NOTES:

1. THE SYSTEM LOCATOR CODE "VES" HAS BEEN OMITTED FROM ALL COMPONENT NUMBERS. THE COMPONENT CODE HAS BEEN OMITTED FROM ALL COMPONENTS EXCEPT EQUIPMENT. REFER TO THE P&ID LEGEND DRAWING GW M6 001, 002 AND 003 FOR ADDITIONAL INFORMATION REGARDING COMPONENT NUMBERING.
2. REFER TO SYSTEM DESCRIPTIONS FOR A DETAILED DESCRIPTION OF ALL INSTRUMENTATION AND CONTROLS.
3. SYSTEM IS FILLED AND REFILLED USING BREATHABLE QUALITY AIR SOURCE.
4. REFER TO BECHTEL DRAWING VBS-M6-002 FOR NORMAL HVAC SYSTEM.
5. SYSTEM ACTUATION ON HIGH - HIGH PARTICULATE OR IODINE RADIOACTIVITY IN THE MCR SUPPLY AIR DUCT OR LOSS OF ALL AC POWER.
6. TEMPORARY PRESSURE INSTRUMENT CONNECTION TO PERMIT ADJUSTMENT OF PRESSURE REGULATING VALVES.
7. DELETED
8. SCREWED CAP CONNECTION IS FITTED WITH AN INTEGRAL BLEED MECHANISM TO RELIEVE LINE PRESSURE.
9. LOW FLOW ALARM TO BE ACTIVATED ON TIME DELAY AFTER VES ACTUATION.
10. PRESSURE RELIEF DAMPERS QUALIFIED TO ASME/ANSI N509 AND N510 AND ARE USED FOR LOW PRESSURE RELIEF OF THE MCR PRESSURE BOUNDARY DURING VES OPERATION.
11. DIFFERENTIAL PRESSURE SIGNAL USED FOR INDICATION AND ALARM FUNCTION FOR VES OPERATION. DAMPER CONTROL FUNCTION PROVIDED FOR VBS OPERATION.
12. MAXIMUM AIR TANK PRESSURE IS 3800 PSIG TO PRECLUDE PROBLEMS WITH RELIEF VALVE RESEATING.
13. PRESSURE RELIEF ISOLATION VALVE TO BE ACTUATED ON TIME DELAY AFTER VES ACTUATION SIGNAL.
14. TEMPORARY PRESSURE INSTRUMENT CONNECTION.
15. VBS DAMPER CONTROL PROVIDED VIA PLS.

Figure 6.4-2 (Sheet 2 of 2)

Main Control Room Habitability System Piping and Instrumentation Diagram

6.5 Fission Product Removal and Control Systems

6.5.1 Engineered Safety Feature (ESF) Filter Systems

This subsection is not applicable to the AP1000.

6.5.2 Containment Spray System

In the event of a design basis LOCA there is an assumed core degradation that results in a significant release of radioactivity to the containment atmosphere. This activity would consist of noble gases, particulates, and a small amount of elemental and organic iodine (as discussed in subsection 15.6.5.3, most of the iodine would be in the particulate form). The AP1000 does not include a safety-related containment spray system to remove airborne particulates or elemental iodine. Removal of airborne activity is by natural processes that do not depend on sprays (that is sedimentation, diffusiophoresis, and thermophoresis). These removal mechanisms are discussed in Appendix 15B.

Much of the non-gaseous airborne activity would eventually be deposited in the containment sump solution. Long-term retention of iodine in the containment sump following design basis accidents requires adjustment of the sump solution pH to 7.0 or above. This pH adjustment is accomplished by the passive core cooling system and is discussed in subsection 6.3.2.1.4.

In accordance with Reference 1, the fire protection system provides a nonsafety-related containment spray function for accident management following a severe accident. This design feature is not safety-related and is not credited in any accident analysis including the dose analysis provided in section 15.6.5. Dose reduction following a severe accident may be enhanced over the natural removal mechanisms via the nonsafety-related containment spray. Subsection 15.6.5.3.2 provides additional discussion of the natural removal mechanisms. The following subsections provide a discussion of the nonsafety-related containment spray function provided by the fire protection system.

6.5.2.1 System Description

The fire protection system provides a nonsafety-related containment spray function for severe accident management. Subsection 9.5.1 provides a description of the fire protection system including equipment and valves that support the containment spray function such as the fire pumps and fire main header. This section provides the description of the portion of the fire protection system designed specifically to provide the containment spray function.

The source of water for the containment spray function is provided by the secondary fire protection system water tank. Either the motor driven or diesel driven fire protection system pump may be used to deliver fire water to the containment spray header. The flow path to containment is via the normal fire main header as shown in Figure 9.5.1-1, sheets 1 through 3. The containment spray flow path is from the fire main extension, through the fire protection system line that penetrates containment, to the containment spray riser that connects to the fire protection system header inside containment. This riser supplies two ring headers located above the containment polar crane.

6.5.2.1.1 Valves

The containment spray flow path from the fire main header contains one normally open manual valve (FPS-V048), one normally closed manual valve (FPS-V101), one lock closed manual containment isolation valve outside containment (FPS-V050), a containment isolation check valve inside containment (FPS-V052), a normally open manual isolation valve in the spray riser (FPS-V700), and a normally closed remotely-operated valve (FPS-V701) downstream of the manual isolation valve in the spray riser.

Containment spray is initiated by first closing the passive containment cooling water system fire header isolation valve (PCS-V005) isolating the primary fire water tank, opening the manual valves outside containment, and by opening the remotely-operated valve inside containment. The manual valves outside containment are located in valve / piping penetration room 12306. The valves are located close to the entrance door such that radiation exposures to an individual required to enter the room and align the valves would not exceed the prescribed post-accident dose limits discussed in subsection 12.4.1.8.

Valve FPS-V701 is a fail-open air-operated valve such that the containment spray flow path can be opened following a loss of the nonsafety-related compressed air system. During shutdown operations, the fire protection system header inside containment is pressurized from the passive containment cooling water storage tank for fire protection and manual isolation valve FPS-V700 is closed.

6.5.2.1.2 Containment Spray Header and Nozzles

The containment spray header consists of a single header that feeds two ring headers located above the containment polar crane. The containment spray ring headers and spray nozzles are oriented to maximize containment volume coverage. A lower ring header is located at plant elevation 260 feet, and contains 44 spray nozzles. An upper ring header is located at plant elevation 275 feet, and contains 24 spray nozzles.

The nozzles within the spray ring header are conventional containment spray nozzles utilized in past Westinghouse pressurized water reactors. The spray nozzles are selected on the basis of drop size to provide adequate absorption of fission products from the containment atmosphere.

6.5.2.1.3 Applicable Codes and Classifications

The containment spray function is not safety-related, and therefore the valves and piping in the containment spray flow path are not required to be safety-related for the containment spray function. However, the containment isolation piping and valves are safety-related (AP1000 Equipment Class B) to perform the safety-related function of containment isolation. The classification of the remaining portions of the fire header are nonsafety-related, and are classified as Class F as discussed in subsections 3.2.2.7 and 9.5.1. The containment spray header and valve, downstream of the manual isolation valve inside containment is nonsafety-related and classified as Class E. The containment spray header is classified as Seismic category II.

6.5.2.1.4 System Operation

During normal operation, the fire protection system header inside containment is isolated from the fire main header by closed isolation valves, including a locked closed containment isolation valve. The containment spray piping is therefore not pressurized during normal operation. During plant shutdown modes, personnel access to containment is required, and as such, the fire protection system standby header inside containment is pressurized by the water in the passive containment cooling water storage tank. During these modes, the manual isolation valve located between the header and the spray ring is closed to further isolate the containment spray header from the passive containment cooling water storage tank. Inadvertent actuation of the containment spray system during power operation and shutdown is not credible. Inadvertent actuation of the containment spray would require multiple failures of closed valves.

Severe accident management guidelines provide the operator with guidance to initiate the containment spray feature of the fire protection system. Operator action to open two manual isolation valves outside of containment followed by remotely opening the containment spray isolation valve within containment from either the main control room or the remote shutdown workstation will initiate the spray function. Containment spray may be terminated at any time by closing the remotely operated isolation valve within containment, or by closing any of the manual valves in the containment spray flow path outside containment. Operation of the containment spray will have no effect on the availability of the remainder of the fire protection system other than the loss of inventory from the secondary fire water tank due to the sprayed water. To preserve inventory for firefighting, the primary fire water tank is isolated during containment spray operation. Since the fire protection system operates in the active standby mode, i.e. the supply piping is kept full and pressurized, once the remotely operated isolation valve is opened the system will perform the containment spray function.

When water pressure in the fire main begins to fall, due to a demand for water from containment spray, the motor-driven pump starts automatically on a low-pressure signal. If the motor-driven pump fails to start, the diesel-driven pump starts upon a lower pressure signal. The pump continues to run until it is stopped manually.

6.5.2.2 Design Evaluation

6.5.2.2.1 Containment Coverage

The containment spray nozzles are the Lechler (SPRACO Company) spray nozzles or equivalent, which provide a drop size distribution which has been established by testing and found suitable for fission product removal. The fire protection system header provides a containment spray nozzle differential pressure of 40 psid, which fixes the drop size distribution. The mass mean drop size produced at this differential pressure is conservatively assumed to be 1000 microns.

The fire protection system header can provide the design flow rate of 15.2 gpm to each spray nozzle at a containment backpressure of 20 psig for a total containment spray flow of approximately 1034 gpm. Analyses of severe accident sequences show that containment backpressure is less than 20 psig after containment spray flow is initiated.

Figure 6.5-1 is a diagram of containment which shows the developed spray patterns for the containment spray ring headers. The overlay of the spray patterns on the containment is useful in illustrating the completeness of spray coverage in the sprayed region. Furthermore, as discussed in reference 2, there is significant momentum exchange between the spray droplets and the closed air volume of the containment, which provides far greater mixing within the sprayed region than the idealized spray patterns would indicate. Therefore, even though small areas of the sprayed region are not directly sprayed by the developed spray patterns, the sprayed region of the containment is well-mixed.

The sprayed regions of containment include the region of containment above the operating deck, and the refueling cavity, which is open at the operating deck. The total free volume of the sprayed region is approximately 1.7 x 10^6 cubic feet which represents approximately 84% of the total containment free volume.

6.5.2.2.2 Aerosol Removal Effectiveness of Sprays

The removal of aerosol activity from the containment atmosphere by sprays is simply described by:

$$C_t = C_o e^{-\lambda t}$$

where:

C_t = concentration of aerosols at time "t"

C_o = initial concentration of aerosols

λ = aerosol removal coefficient for sprays (hr^{-1})

t = elapsed time (hr)

However, to fully model the removal of aerosols from the containment atmosphere in a severe accident, the analysis also needs to take into account mixing between the sprayed and unsprayed regions and the rate of release of activity from the core into the containment atmosphere.

6.5.2.2.3 Aerosol Removal Coefficient for Sprays

The aerosol removal coefficient for sprays is calculated by the following equation from the Standard Review Plan (Reference 2):

$$\lambda = 3hfE / 2Vd$$

where:

h = average spray drop fall height (ft)

f = spray flow rate (ft^3/hr)

E = collection efficiency

V = volume of the containment exposed to sprays

d = average spray drop diameter (ft)

Reference 2 identifies a value for E/d of 3.05 ft^{-1} as being conservative until the air concentration is reduced by a factor of 50. Using this together with a nominal spray fall height of 125 feet and a nominal flow rate of 1000 gpm (8022 ft^3/hr), the aerosol removal coefficient for the containment sprays is approximately 2.7 hr^{-1} in the sprayed volume. This spray removal coefficient is significantly greater than that associated with the natural removal mechanisms assumed in the design basis analysis (see Appendix 15B) and would enhance dose reduction following a severe accident.

The decontamination factor (DF) that would be achieved at any point in time is dependent on the timing of spray operation. Additionally, the continuing release of activity must be factored into the determination of DF (i.e., the DF would be based on the integrated activity release to the containment at a point in time, not on the amount of activity present in the containment atmosphere at the time spray operation is initiated). After a DF of 50 is reached, the value of E/D would be reduced by a factor of ten (Reference 2) and the aerosol removal coefficient would also be reduced by the same factor to a value of 0.27 hr^{-1}. Based on an assumed spray actuation shortly after the onset of core melt and a nominal spray duration of three hours, the DF of 50 would not be reached until after spray operation was terminated.

6.5.3 Fission Product Control Systems

The containment atmosphere is depleted of elemental iodine and particulates as a result of the passive removal processes discussed in DCD Appendix 15B. No active fission product control systems are required in the AP1000 design to meet regulatory requirements. The passive removal processes and the limited leakage from the containment of less than L_a as defined in the Containment Leakage Rate Testing Program, result in doses less than the regulatory guideline limits. (See subsection 15.6.5.3.)

6.5.3.1 Primary Containment

The containment consists of a freestanding cylindrical steel vessel with ellipsoidal heads. The containment structural design is presented in subsection 3.8.2.

The containment vessel, penetrations, and isolation valves function to limit the release of radioactive materials following postulated accidents. The resulting offsite doses are less than regulatory guideline limits. Containment parameters affecting fission product release accident analyses are given in Table 6.5.3-1.

Long-term containment pressure and temperature response to the design basis accident are presented in Section 6.2.

The containment air filtration system may be operated for personnel access to the containment when the reactor is at power, as presented in subsection 9.4.7. For this reason, the radiological

assessment of a loss-of-coolant accident assumes that both trains of the air filtration system are in service at the initiation of the event. The isolation valves receive automatic signals to close from diverse parameters. The valves are designed to close automatically as described in subsection 6.2.3.

Containment hydrogen control systems are presented in subsection 6.2.4.

6.5.3.2 Secondary Containment

There is no secondary containment provided for the fission product control following design basis accident.

The annulus between containment and shield building from the elevation 100′-0″ to the elevation 132′-3″ acts as a holdup volume to limit the spread of fission products following severe accident. Most containment penetrations are located within this holdup volume. It is served by the radiologically controlled area ventilation system (VAS) described in subsection 9.4.3. Isolation dampers are provided to reduce the air interchange between the holdup volume and environment. Fission product control via holdup within the annulus is considered in severe accident dose analysis but excluded from consideration for design basis accident dose evaluations presented in Chapter 15.

6.5.4 Combined License Information

This section has no requirement for additional information to be provided in support of the Combined License applications.

6.5.5 References

1. SECY-97-044, "Policy and Key Technical Issues Pertaining to the Westinghouse AP600 Standardized Passive Reactor Design," June 30, 1997.

2. NUREG-0800, Section 6.5.2, Revision 2, "Containment Spray as a Fission Product Cleanup System."

Table 6.5.3-1

PRIMARY CONTAINMENT OPERATION FOLLOWING A DESIGN BASIS ACCIDENT

Type of structure	Freestanding cylindrical steel vessel with ellipsoidal heads
Containment free volume (ft^3)	2.06×10^6
Design Basis Containment leak rate	0.10% containment volume per day

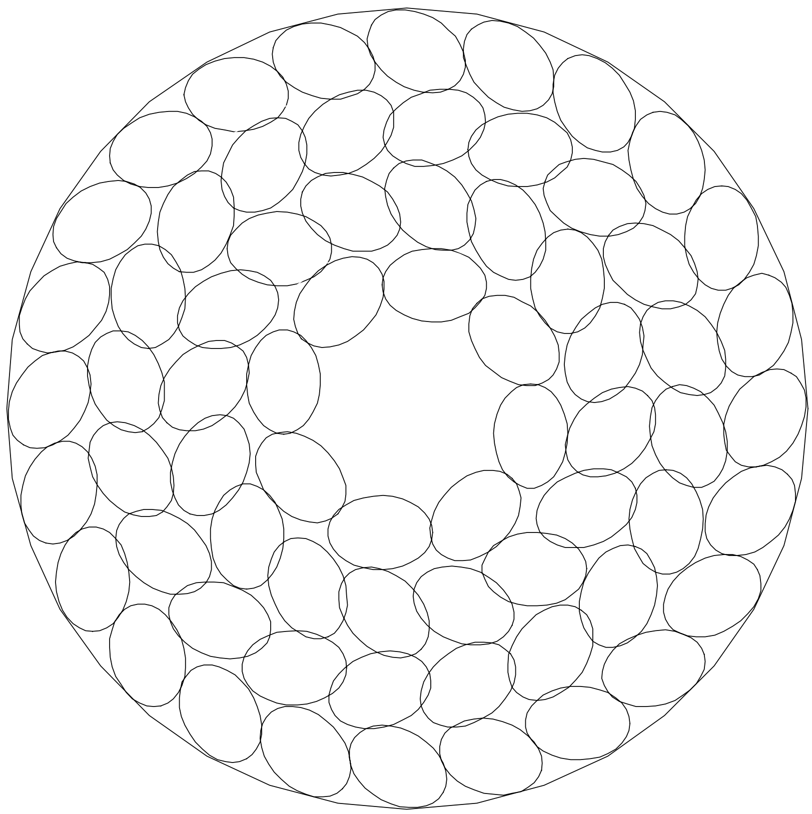


Figure 6.5-1

Containment Spray Coverage At the Operating Deck

6.6 Inservice Inspection of Class 2 and 3 Components

6.6.1 Components Subject to Examination

Preservice and inservice inspections of Quality Group B and C pressure retaining components (ASME Code, Section III Class 2 and 3 components) such as vessels, piping, pumps, valves, bolting, and supports as identified in subsection 3.2.2 are performed in accordance with the ASME Code, Section XI, as required by 10 CFR 50.55a(g). This includes the ASME Code Section XI Mandatory Appendices.

In conformance with ASME Code and NRC requirements, the preparation of inspection and testing programs is the responsibility of the Combined License applicant of each AP1000. Preparation of the pre-service inspection program (nondestructive examination) is the responsibility of the Combined License applicant. The inservice inspection program is the responsibility of the Combined License applicant prior to commercial operation. These programs will address applicable inservice inspection provisions of 10 CFR 50.55a(g). The pre-service program will provide details of areas subject to inspection, as well as the method and extent of pre-service inspection. The inservice inspection program will detail the areas subject to inspection and method, extent, and frequency of inspection. The description of these programs is the responsibility of the Combined License applicant.

6.6.2 Accessibility

ASME Code Class 2 and 3 components are designed so that access is provided in the installed condition for visual, surface and volumetric examinations specified by the ASME Code. See subsection 5.2.1.1 for a discussion of the baseline ASME Code edition and Addenda. Design provisions, in accordance with Section XI, IWA-1500, are formally implemented in the Class 2 and 3 component design processes.

The goal of designing for inspectability is to provide for the inspectability access and conformance of component design with available inspection equipment and techniques. Factors such as examination requirements, examination techniques, accessibility, component geometry and material selection are used in evaluating component designs. Examination requirements and examination techniques are defined by inservice inspection personnel. Inservice inspection review as part of the design process provides component designs that conform to inspection requirements and establishes recommendations for enhanced inspections.

Considerable experience has been drawn on in designing, locating, and supporting Quality Group B and C (ASME Class 2 and 3) pressure-retaining components to permit pre-service and inservice inspection required by Section XI of the ASME Code. Factors such as examination requirements, examination techniques, accessibility, component geometry, and material selections are used in establishing the designs. The inspection design goals are to eliminate uninspectable components, reduce occupational radiation exposure, reduce inspection times, allow state-of-the-art inspection systems, and enhance detection and the reliability of flaw characterization. There are no Quality Group B and C components which require inservice inspection during reactor operation.

Removable insulation is provided on piping systems requiring volumetric and surface inspection. Removable hangers and pipe whip restraints are provided, as necessary and practical, to facilitate inservice inspection. Working platforms are provided in areas requiring inspection and servicing of pumps and valves. Temporary or permanent platforms, scaffolding, and ladders are provided to facilitate access to piping welds. The components and welds requiring inservice inspection are designed to allow for the application of the required inservice inspection methods, that is, sufficient clearances for personnel and equipment, maximized examination surface distances, two-sided access, favorable materials, weld joint simplicity, elimination of geometrical interferences, and proper weld surface preparation.

Many of the ASME Code, Section III, Class 2 and 3 components are included in modules which are fabricated offsite and shipped to the site, as described in subsection 3.9.1.5. The modules are designed and engineered to provide access for in-service inspection and maintenance activities. The attention to detail that is engineered into the modules prior to construction improves the accessibility for inspection and maintenance.

Relief from Section XI requirements will not be required for ASME Code, Section III, Class 2 and 3 pressure-retaining components in the AP1000 plant for the baseline design certification code. Future unanticipated changes in the Section XI requirements could, however, necessitate relief requests. Relief from the inspection requirements of Section XI will be requested when full compliance is not practical according to the requirements of 10 CFR 50.55a. In such cases, specific information will be provided to identify the applicable ASME Code requirements, justification for the relief request, and the inspection method to be used as an alternative.

Space is provided to handle and store insulation, structural members, shielding, and other material related to the inspection. Suitable hoists and other handling equipment, lighting, and sources of power for inspection equipment are installed at appropriate locations.

6.6.3 Examination Techniques and Procedures

The visual, surface, and volumetric examination techniques and procedures are in accordance with the requirements of ASME Code, Section XI, subarticle IWA-2000. Code cases listed in Regulatory Guide 1.147 are applied as the need arises during the pre-service inspection. Code cases determined as necessary to accomplish pre-service inspection activities are used.

The liquid penetrant or magnetic particle methods are used for surface examinations. Radiography, ultrasonic, or eddy current methods (whether manual or remote) are used for volumetric examinations.

The report format for reportable indications and data compilation provide for comparison of data from subsequent examinations.

6.6.4 Inspection Intervals

Inspection intervals included in the inspection program are as defined in subarticle IWA-2400 of the ASME Code, Section XI. The periods within each inspection interval may be extended by as much as one year to permit inspections to be concurrent with plant outages. It is intended that

inservice examinations be performed during normal plant outages, such as refueling shutdown or maintenance shutdowns occurring during the inspection interval.

6.6.5 Examination Categories and Requirements

Examination categories and examination requirements (examination methods, acceptance criteria, extent of examination, and frequency of examination) for Class 2 components are in accordance with Subsection IWC and table IWC-2500 of the ASME Code, Section XI. Similar information for Class 3 components are in conformance with Article IWD-2000 and table IWD-2500 of ASME Code, Section XI. The pre-service examination of Class 2 components is according to the requirements of Subarticle IWC-2200. The pre-service examination of Class 3 components is according to the requirements of Subarticle IWD-2100. Inservice test requirements for component supports comply with ASME Code, Section XI, Article IWF-5000.

6.6.6 Evaluation of Examination Results

Examination results are evaluated per the acceptance standards found in IWA-3000, IWC-3000, and IWD-3000 of the ASME Code, Section XI. Repair procedures are in accordance with ASME Code, Section XI, Article IWA-4000. If the guidelines of IWA-4000 are inappropriate for the components, then the guidelines of ASME Code Section XI, IWC-4000 and IWD-4000 apply.

6.6.7 System Pressure Tests

System pressure tests comply with IWA-5000, IWC-5000 and IWD-5000 of the ASME Code, Section XI, for Class 2 and 3 components.

6.6.8 Augmented Inservice Inspection to Protect against Postulated Piping Failures

An augmented inspection program is developed for high-energy fluid systems piping between containment isolation valves. Such a program is also developed where no isolation valve is used inside containment between the first rigid pipe connection to the containment penetration or the first pipe whip restraint inside containment and the outside isolation valve. This program provides for 100 percent volumetric examination of welds in the affected piping during each inspection interval, conducted according to the ASME Code, Section XI. The program covers the break exclusion portion of high-energy fluid systems described in subsections 3.6.1 and 3.6.2.

There is no requirement for an augmented inspection of ASME Code, Section III Class 1, 2, or 3 pipe to address erosion-corrosion-induced pipe wall thinning. Class 1, 2, and 3 pipe containing single-phase water or two-phase steam and water is fabricated of erosion-corrosion resistant material. See Section 10.1 for information on monitoring of nonsafety-related pipe for erosion-corrosion.

6.6.9 Combined License Information Items

6.6.9.1 Inspection Programs

Combined License applicants referencing the AP1000 certified design will prepare a pre-service inspection program (nondestructive examination) and an inservice inspection program for ASME

Code, Section III Class 2 and 3 systems, components, and supports. The pre-service inspection program will address the equipment and techniques used.

6.6.9.2 Construction Activities

Combined License applicants referencing the AP1000 certified design will address the controls to preserve accessibility and inspectability for ASME Code, Section III, Class 2 and 3 components and piping during construction or other post design certification activities.

APPENDIX 6A

FISSION PRODUCT DISTRIBUTION IN THE AP1000 POST-DESIGN BASIS ACCIDENT CONTAINMENT ATMOSPHERE

The AP1000 design-basis analyses for hydrogen control (subsection 6.2.4.3) and natural aerosol removal coefficient (Appendix 15B) assume that the fission products and hydrogen released to the containment following a postulated design basis loss of coolant accident (LOCA) are homogeneously distributed in the containment atmosphere within the open compartments that participate in natural circulation. The purpose of this discussion is to justify the homogeneous assumption for aerosol natural deposition calculations.

The following evaluation includes:

- Identification of the accident sequence assumptions and boundary conditions in the reactor coolant system and containment prior to the fission product and hydrogen releases
- Identification of the limiting steam and fission product release location from the reactor coolant system to the containment
- Discussion of containment natural circulation in quasi-steady conditions
- Discussion of AP1000 passive containment cooling system (PCS) large-scale test (LST) insights that support the well-mixed assumption

6A.1 Design Basis Sequence Assumptions

The design-basis fission product source term (subsection 15.6.5.3.1) is superimposed onto thermal-hydraulic conditions of the design-basis accident sequence for the evaluation of fission product deposition. The following assumptions define the design basis conditions. The AP1000 design-basis sequence consists of a LOCA which drains the reactor coolant system (RCS) and core makeup tanks (CMTs) sufficiently to activate the automatic depressurization system (ADS). Both trains of all four stages of automatic depressurization system open sequentially. During the depressurization, the core makeup tanks and accumulators inject into the reactor vessel downcomer. The final reactor coolant system pressure is essentially equal to the containment pressure which allows gravity injection of the IRWST water. Steam is produced in the vessel at the rate dictated by decay heat minus the heat in the volatile fission products which have been released from the core. The passive containment cooling system water flow is initiated based on high containment pressure from the blowdown or the automatic depressurization system prior to the release of fission products.

Fission product release occurs from a fully depressurized reactor coolant system. The aerosols are carried into the containment in a buoyancy-driven steam flow. The earliest time of fission product release from core degradation is well past the time of the blowdown and automatic depressurization. The containment condition during and following the release is quasi-steady-state. Internal heat sinks are assumed to be essentially thermally-saturated and no longer effective,

and the condensation rate of steam on the containment dome and shell is equivalent to the decay heat steaming rate.

6A.1.1 Break Size and Fission Product Release Location in Containment

This section discusses each of the postulated fission product release locations from the reactor coolant system, the containment location for each, the size limitations and the phenomena associated with the break locations. It is shown that it is appropriate to assume that the steam and fission products are released from the reactor coolant system hot leg to the containment above the maximum water flood-up elevation in the steam generator compartment gas space.

6A.1.1.1 Releases From Depressurization System Lines

Any design-basis LOCA which can be postulated to produce a large core activity release to containment will actuate the four stages of the automatic depressurization system. The stage 1, 2 and 3 automatic depressurization system lines, which relieve from the top of the pressurizer (see Figure 6A-1), deliver flow to the containment through the in-containment refueling water storage tank (IRWST). This is not considered to be a major fission product release pathway because the IRWST is a cold, effectively closed system with no leakage pathway to the environment. The IRWST is nearly full of water during the depressurization blowdown which would trap any postulated fission products released to the IRWST. At the time the water is drained below the spargers, the reactor coolant system is depressurized with stage 4 automatic depressurization system open, and the IRWST vents, which are closed with flappers, are not expected be significantly opened by the small buoyancy-driven flows. Aerosols released from stages 1, 2 and 3, either before or after the draining of the IRWST, would essentially be trapped in the water or in the IRWST compartment. Therefore, this pathway is conservatively neglected as a release pathway from the reactor coolant system to maximize the activity entering the containment atmosphere.

Stage 4 automatic depressurization system lines relieve reactor coolant system coolant, steam, and fission products from the hot legs (see Figure 6A-1) to the steam generator compartments above the maximum water flood-up level. The stage 4 lines consist of four 14-inch schedule 160 lines. Two lines are connected to each of the two hot legs. Each of these trains relieves at the 112-foot elevation to a steam generator compartment.

Of the postulated release locations in the reactor coolant system, openings in the hot-side piping, such as the stage 4 automatic depressurization system, provide the lowest resistance pathway for fission product releases to the containment because of the large flow area, high temperatures, short resident time and low surface area for aerosol deposition in the reactor coolant system. To reach openings in the cold side piping when stage 4 automatic depressurization system valves are open, the reactor coolant system low-pressure natural circulation flow must pass through the steam generator tubes (see Figure 6A-1). At the superheated steam temperature of the gas which accompanies the fission product flow, significant heat transfer would take place in the steam generator tubes which are cooled on the secondary side by water. Aerosol deposition to the tubes would remove fission products from the release before the flow reached the containment. Therefore, releases from cold-side breaks are less severe than hot side breaks with the stage 4 automatic depressurization system open.

6A.1.1.2 Releases From Coolant Loop Breaks

Breaks in the reactor coolant system loop piping (hot legs or cold legs) relieve primary coolant, steam and fission products to the steam generator compartments. Assuming double-ended guillotine breaks, the hot-leg break has a diameter of 31 inches (78.7 cm) and the cold-leg break has a diameter of 22 inches (55.9 cm). Breaks in the hot leg piping are more limiting than breaks in the cold leg with respect to the fission product releases to the containment because of the larger break area, higher temperatures, shorter resident time and lower surface area for aerosol deposition in the reactor coolant system. Therefore, of the coolant loop breaks, hot leg breaks to the steam generator compartment provide the more conservative magnitude of fission product release to the containment. Because of the similar fission product flow path, release magnitude and release location, the hot leg breaks can be lumped with the stage 4 automatic depressurization system releases.

6A.1.1.3 Direct Vessel Injection Line Breaks

A break in one of the two direct vessel injection lines can relieve steam and fission products outside the steam generator compartments to one of the two dead-ended accumulator compartments below the core makeup tank room. The piping is 8-inch diameter schedule 160 piping, but an orifice at the reactor vessel wall limits the break size to a 4-inch diameter. The nozzle connects to the reactor vessel downcomer (see Figure 6A-1), so all direct vessel injection line breaks relieve from the cold-side of the reactor coolant system. The accumulator compartments have significant heat sink surfaces (equipment, grating, support structures and compartment walls) for aerosol deposition to trap fission products within the dead-ended compartment. Given the small break size, cold-side location of the break, the compartment retention capacity, and the large relief flow area associated with the open stage 4 automatic depressurization system valves, very little fission product release is expected from the direct vessel injection line. The steam release to an accumulator compartment is negligible with respect to that from the stage 4 automatic depressurization system.

6A.1.1.4 Core Makeup Tank Balance Line Breaks

Breaks in the core makeup tank balance lines can relieve steam and fission products to the core makeup tank room. The balance line piping is 8-inch diameter schedule 160 piping. The balance line nozzle is attached to a cold leg (see Figure 6A-1). Given the small break size, cold-side location of the break, the compartment retention capacity, and the large relief flow area associated with the open stage 4 automatic depressurization system valves, very little fission product release is expected from the balance line. The steam, hydrogen and fission product releases to the core makeup tank room is negligible with respect to the release from the stage 4 automatic depressurization system.

6A.1.1.5 Chemical and Volume Control System Line Breaks

A break in the chemical and volume control system (CVS) line relieves to the dead-ended chemical and volume control system compartment below the core makeup tank room. The chemical and volume control system piping is 3-inch diameter schedule 160 piping. The inlet of the chemical and volume control system draws from the cold leg and the outlet discharges to the

reactor coolant pump suction, both on the cold-side of the reactor coolant system (see Figure 6A-1). Given the small break size, cold-side location of the break, the compartment retention capacity, and the large relief flow area associated with the open stage 4 automatic depressurization system valves, very little fission product release is expected from the chemical and volume control system piping. The steam release to the chemical and volume control system compartment is negligible with respect to that from the stage 4 automatic depressurization system.

6A.1.1.6 Fission Product Release Location Conclusion

The fission product releases are expected to discharge mainly from the stage 4 automatic depressurization system lines, which relieve from the hot legs to the steam generator compartments. Stage 4 automatic depressurization system is open in all design-basis LOCA sequences that can be postulated to produce large core activity releases to the containment. For a coolant loop break, the release would also go to the steam generator compartments along with the releases from the stage 4 automatic depressurization system lines. Fission products released to other postulated containment locations are negligible by comparison because the releases are from the cold-side of the reactor coolant system through comparatively long and narrow piping pathways. Therefore, the bounding release pathway is a hot-side break into the steam generator compartments with fission product and steam releases through the break and stage 4 automatic depressurization system.

6A.2 Containment Natural Circulation and Mixing

This section describes the natural circulation flow path and the entrainment processes in the containment atmosphere. Figure 6A-2 graphically depicts the containment natural circulation flow paths and the entrainment processes.

The steam plume, rising from a point low in the containment, and the condensation on the containment surface and wall entrainment rates provide the driving forces for natural circulation in the containment. Based on the sequence timing, the containment conditions at the time of the fission product releases are quasi-steady-state. Therefore, it is assumed:

$$Q_{st} \approx \text{constant}$$
$$Q_{cond} = Q_{st}$$

where:

Q_{st} = steam volumetric flowrate
Q_{cond} = condensation volumetric flowrate.

Steam and fission products are released low in the containment through stage 4 automatic depressurization system at the 112-foot elevation as hot, buoyant plumes from the low pressure primary system into the steam generator compartments. Entrainment into the rising plume drives circulation of surrounding atmosphere into the bottom of the steam generator compartment through the openings to the core makeup tank room. The fission products are released from the reactor coolant system with the steam plumes. The plumes rise through the steam generator compartments, mix with the flow entrained from below and are released into the upper compartment at the top of the steam generator doghouses (153-foot elevation). The plumes rise

unconstrained for over 100 feet in the containment. As the plumes rise, the surrounding upper compartment gas mixture is entrained. The steam, fission products and any non-condensable gases (e.g. hydrogen and air) in the plumes are mixed with a large volume of entrained atmosphere in the rising plume.

An estimate of the volume entrained into the plume above the operating deck is made conservatively neglecting entrainment into the lower steam generator compartment, and assuming the plumes from the two steam generator compartments behave as one:

$$Q_{ent} = 0.15 * B^{1/3} * Z^{5/3} \quad \text{(Reference 1)}$$

where:

Q_{ent}	=	volumetric flowrate of entrained gas in the rising plume above the operating deck
Z	=	height of rising plume
B	=	$g * Q_{ST} * (\rho_{amb} - \rho_{st})/\rho_{amb}$
g	=	gravitational acceleration

The fission product releases occur at approximately 1 hour when the best estimate (no uncertainty) 1979 ANS decay heat rate is 1.4%. At one hour, the volatile fission products which are released from the core contribute 30% of the decay heat, so the decay heat fraction is 1.0% and 34 MW of steam is generated in the reactor vessel. At a containment pressure of approximately 50 psia, the source flow is approximately 295 ft^3/sec and $\Delta\rho/\rho$ is approximately 1/4. Thus, $B^{1/3} = 13.3\ ft^{4/3}$/sec. For a release into the upper compartment where Z = 125 ft, $Q_{ent} = 6250\ ft^3$/sec and $Q_{ent}/Q_{st} = 21.2$.

At 24 hours, best estimate (no uncertainty) 1979 ANS decay heat is 0.6%, and the volatile fission products released from the core contribute 15% of the decay heat. The heat generated in the vessel, generating steam is 17.3 MW, assuming the containment pressure is 34 psia and $\Delta\rho/\rho$ = 0.32. So the source flow is approximately 216 ft^3/sec, $B^{1/3} = 13.1\ ft^{4/3}$/sec, $Q_{ent} = 6142\ ft^3$/sec and $Q_{ent}/Q_{st} = 28.4$. Therefore, for the AP1000 height above the operating deck, a conservative entrainment ratio for times greater than 1 hour after accident initiation is:

$$Q_{ent}/Q_{st} > 20$$

The application of water to the external surface of the containment shell maintains the containment shell at a cool temperature. The condensation of steam on the containment shell creates a heavy, air-rich downward flowing gas boundary layer on the wall. Fission products are carried along in the wall layer flow. As it flows downward along the wall, the wall layer also entrains surrounding mixture. Thus, the circulation flow rate in the above-deck volume generates significant circulation flow.

A review of literature on circulation within enclosures (appendix 9.C of Reference 2) shows that as long as there is cooling on the inner surface of the containment shell, there are no regions of stratification in the containment including under the containment dome. There are significant recirculation flows in the stratified regions between the plume and the wall layer. Thus concentration gradients are small and there are no stagnant regions above the operating deck.

The circulation time constant due to entrainment above the operating deck for the AP1000 can be estimated by $V/(20*Q_{st})$, where V is the containment volume above the operating deck, and the steam generator compartments and core makeup tank room above the 108′ elevation, $2.0x10^6$ ft^3. Therefore, the circulation time constant at 1 hour is approximately 340 seconds. At 24 hours it is 462 seconds. The time constant is estimated to be conservatively large as it does not include entrainment into the downward flowing wall layer. At 1 hour, during the fission product release, the time constant of 340 seconds is very short compared to the 1.3 hour fission product release duration. Therefore, the fission products can be assumed to be homogeneous within the gas volume as soon as they are released. There is no stagnant region in the upper compartment as the entire volume participates in the rising plume, entrainment flow and wall layer. Stratification exists in the form of a relatively shallow, continuous vertical steam gradient as discussed in section 3.0.

Over the time period of interest, no mechanisms exist to separate the non-condensable gases (air and hydrogen) once they are mixed in the rising plumes. The molecular weight difference is so overwhelmed by natural circulation it does not lead to gravitational separation. The terminal gravitational settling rate of hydrogen in air at 1 atm and 25°C is less than 10^{-6} cm/sec (Reference 4). Over the height of the upper compartment, 125 ft, the average separation length is 62.5 ft (1588 cm) so the time for gravitational separation of the hydrogen and air is $1.6x10^9$ seconds. By comparing the separation time to the time constant for the plume entrainment circulation (463 seconds) it is determined that the separation rate is orders of magnitude less effective than the convective mixing forces. Thus gravity effects do not lead to separation of hydrogen from the non-condensable mixture.

As the downward boundary layer flow reaches the operating deck (135-foot elevation), it has been cooled and somewhat depleted of steam. The air, hydrogen and fission products remain well-mixed in the flow. Vents in the operating deck (135′ elevation, see Figure 6A-2) and a gap between the operating deck and the containment wall allow the denser gases to "drain" down into the maintenance floor area and vertical access tunnel through two large vertical openings which empty to the steam generator compartments. Little condensation is expected below the operating deck in the quasi-steady-state condition as the metal heat sinks are essentially thermally-saturated. The condensation on heat sinks below the operating deck is small compared to that on the steel shell. The maintenance floor area and vertical access tunnel communicates with the steam generator compartments such that air flow will freely pass to the steam generator compartments. In the steam generator compartment, the circulation flow is entrained by the initial steam source, and the circuit begins again.

The accumulator and chemical and volume control system compartments and the reactor cavity, including the reactor coolant drain tank room, do not participate in the large-scale natural circulation flow as they are dead-ended or filled with water. The IRWST compartment is essentially sealed at the vents by flappers after blowdown. The accumulator and chemical and volume control system compartments, IRWST, reactor cavity and reactor coolant drain tank compartments are not considered in the calculation of the aerosol deposition.

6A.3 Insights From the Passive Containment Cooling System Large Scale Test and AP1000 Stratification Studies

The AP600 Passive containment cooling system Large Scale Test (LST) provides insight into the circulation and stratification behavior in the AP1000 containment. The following results are consistent with international test data from various scales (Reference 2, appendix 9.C). Since the large scale test did not include a flow path into the simulated steam generator compartment, the degree of mixing of injected light non-condensable gases with the existing air throughout the test vessel is conservatively underestimated. This is because the extra flow path would allow density-driven circulation through the path into the compartment, introducing an additional mixing mechanism which exists in AP1000.

In the large scale test rising plume, large amounts of surrounding air-steam mixture were entrained with the released gases. Estimates of entrainment above the deck in large scale test show that about one times the break volumetric flow is entrained. In several large scale test tests, 217.1, 218.1, 219.1, and 221.1, in which helium (a hydrogen simulant) was released in an amount equal to 10-20 volume percent, non-condensable gas concentrations were measured (Reference 3). The helium fraction was reduced from 100% at the release point to 50% of the non-condensable gas in the dome during the initial period of injection. For design basis hydrogen releases, the hydrogen concentration as a fraction of the non-condensable gas in the dome would be much less due to the increased height for entrainment.

The existence of circulation under the dome in the large scale test can be seen based on the reduction of helium non-condensable fraction over time after the helium release stops. The mixing of helium above the deck establishes homogeneous concentrations in only a few minutes in the large scale test. Note that it was seen to take hours for the circulation to mix the injected helium with the non-condensable gases in the compartment below the deck, however, this was due to a lack of a flow path in the simulated steam generator compartments. Because of the additional height for entrainment in the AP1000, circulation is about 10 times greater than in the large scale test based on plume entrainment alone. Wall layer entrainment and circulation through the steam generator compartment would further increase the circulation in AP1000. This result indicates that in the AP1000 circulation distributes the injected non-condensable gases with the air throughout the containment quickly compared to the rate of release.

The effect of external cooling on non-condensable gas distributions was studied in large scale test 219.1 which started out with a dry external shell, injected helium, and then initiated the external water cooling. Non-condensable gas data showed that the application of external cooling acts to accelerate the mixing of non-condensable gases, which is probably due to the higher wall layer entrainment rate from the higher condensation rate on the cooler shell.

As discussed above, the fluid dynamics of entrainment into a buoyant plume and wall boundary layers generate large amounts of circulation within the above deck region. Thus, the region is not a static, layered stratification, and there are no stagnant pockets of gases that do not participate in the circulation. The physics do, however, lead to a standing vertical steam density gradient in the circulating stratified region, which will tend to be slightly richer in steam at the top due to the lower density of the injected steam.

Based on the above, at quasi-steady conditions, the decay heat steaming and heat and mass transfer to the steel shell create natural circulation in the containment that mixes the fission products and hydrogen quickly throughout the circulating volume. Circulation time constants indicate that it is reasonable to assume non-condensable gases and fission products can be assumed to be homogeneous in the volumes participating in the circulation. The rising plume and the cooling of the shell create a vertical steam density gradient and a vertical temperature gradient in the upper compartment circulating stratified region. The density and temperature gradients result from a balance between the forces that drive the natural circulation. In the evaluation, no credit is taken for cold plumes falling from the containment dome which cause further circulation above the operating deck.

In reference 5, studies were performed to demonstrate that the AP1000 containment is at least as well-mixed as the AP600 containment. Studies performed indicate the increase in containment height slightly improves the steady state mixing for the AP1000 when compared to the AP600, and therefore the conclusions regarding the mixing characteristics of the AP600 containment can be applied to the AP1000 containment.

Based on the above, condensation and sensible heat transfer occur over the entire steel shell, albeit at different rates over the height of the shell. As shown in Appendix 15B, thermophoresis and diffusiophoresis are directly related to the heat and mass transfer. Fission products are present at all sites of steam condensation and sensible heat transfer in the containment. In Appendix 15B, the processes are modeled by assuming homogeneous aerosol mass distribution throughout the circulating volume and averaging the steam condensation and sensible heat transfer over the entire upper shell. This treatment provides a valid estimate of the aerosol deposition rates.

6A.4 Conclusions

Based on first principal arguments and insight from testing at various scales, the following conclusions are made with respect to mixing in the AP1000 containment during quasi-steady conditions:

- As long as there is cooling on the inner surface of the containment shell, downward wall flow will prevent stagnation under the dome

- No unmixed pockets develop as the doorways extend to the floor and vents are in the ceiling. For the rooms participating in the natural circulation flow, the entire volume participates in the circulation

- The rising plume, condensation of steam on the containment shell, and downward flowing wall layer create vertical steam density and temperature gradients above the operating deck

- Fission products and hydrogen are quickly and uniformly mixed, relative to the duration of the release, in the containment volumes participating in the natural circulation

- For the purpose of calculating long-term aerosol deposition, it is reasonable to assume that aerosols and non-condensable gases are homogeneous throughout the major compartments participating in the containment natural circulation: the steam generator compartments, upper compartment and core makeup tank room.

6A.5 References

1. Peterson, P., "Scaling and Analysis of Mixing in Large Stratified Volumes," International Journal of Heat and Mass Transfer, Vol. 37, Supplement 1, pp. 97-106, 1994.

2. WCAP-15846 (Proprietary) and WCAP-15862 (Non-Proprietary) "WGOTHIC Application to AP600 and AP1000," Revision 1, March 2004.

3. WCAP-14135, Final Data Report for Passive Containment Cooling System Large Scale Test, Phase 2 and Phase 3, Revision 3, November 1998.

4. Linder, P., "Air Filters for Use in Nuclear Facilities," Technical Report Series #122, Guidebook prepared under the auspices of the International Atomic Energy Authority, 1970.

5. WCAP-15613 (Proprietary) and WCAP-15706 (Non-Proprietary), "AP1000 PIRT and Scaling Assessment Report," Revision 0, March 2001.

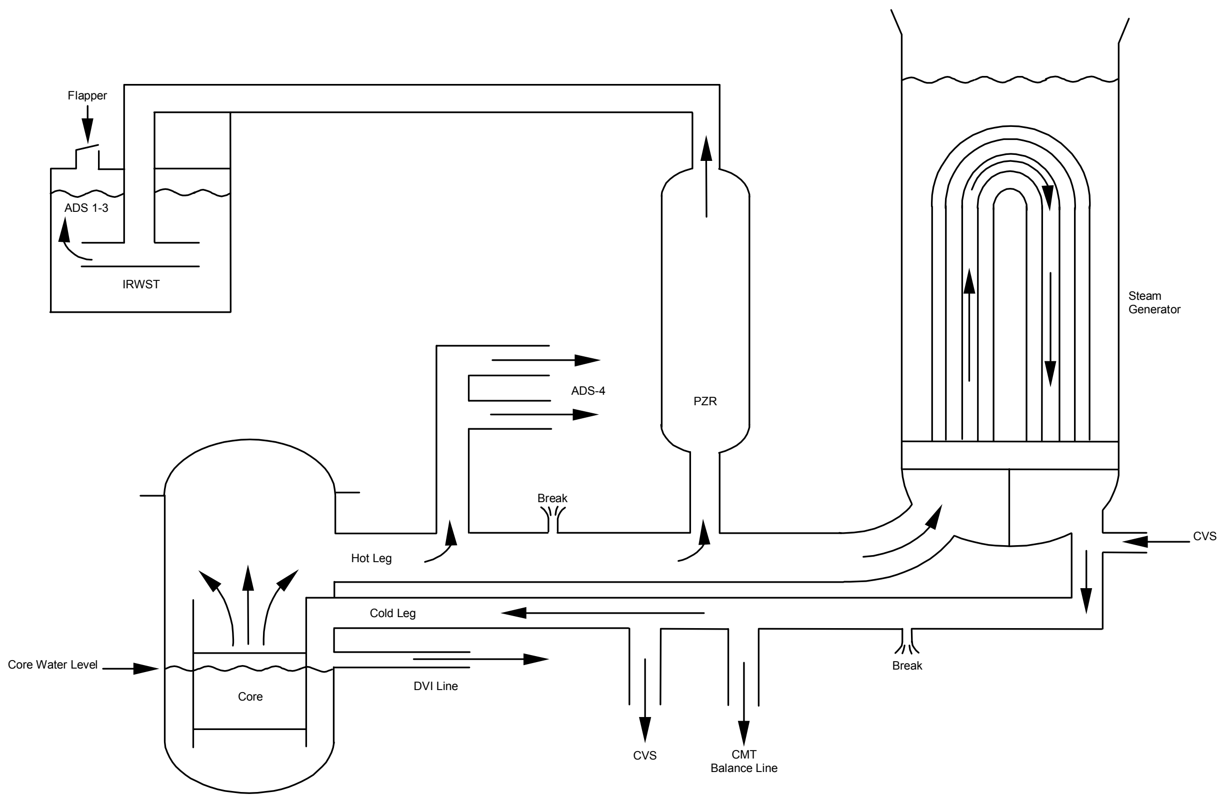


Figure 6A-1

RCS Release Locations

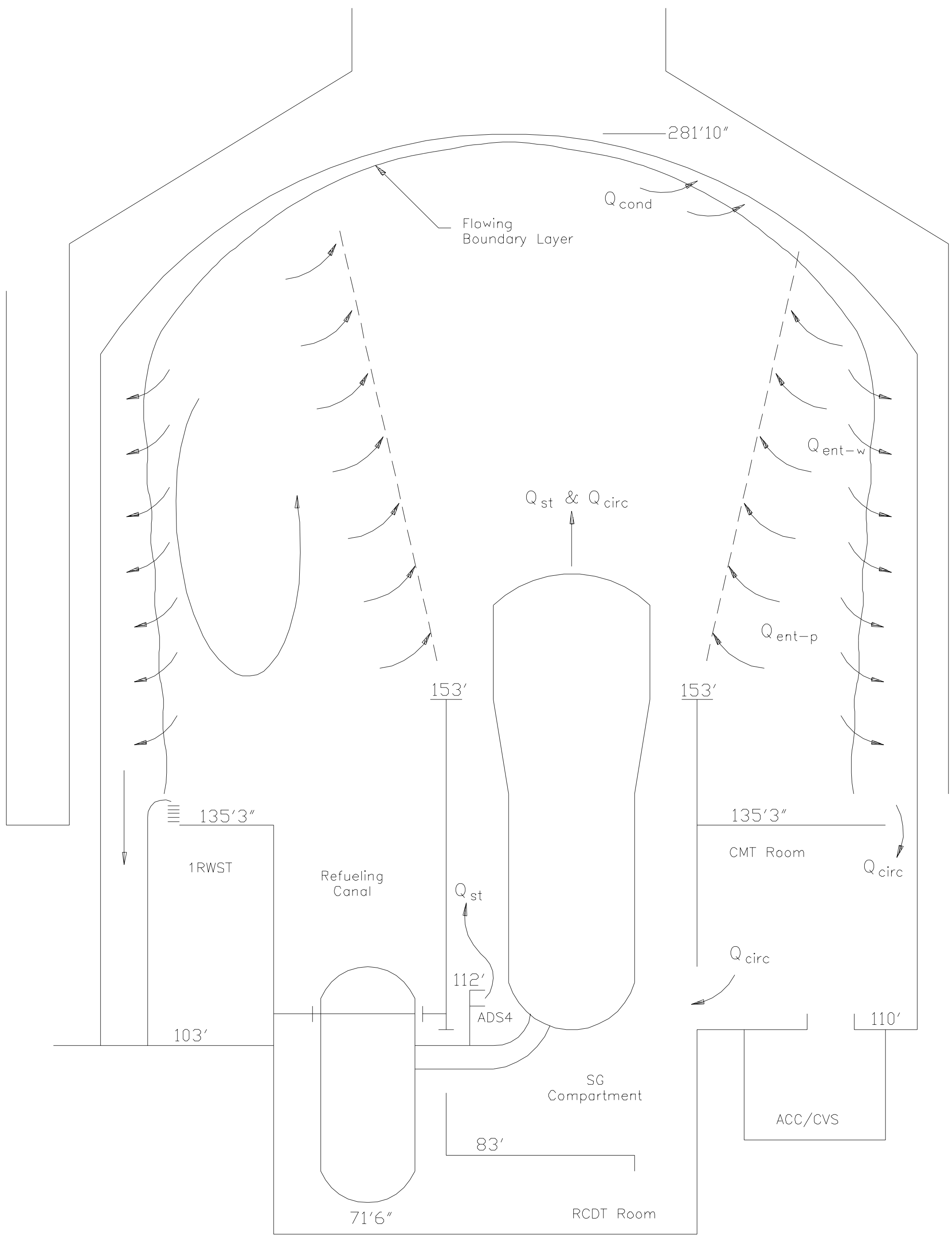


Figure 6A-2

Containment Natural Circulation

TABLE OF CONTENTS

TABLE OF CONTENTS (Cont.)

TABLE OF CONTENTS (Cont.)

LIST OF TABLES

LIST OF FIGURES

LIST OF FIGURES

CHAPTER 7

INSTRUMENTATION AND CONTROLS

7.1 Introduction

The instrumentation and control systems presented in this chapter provide protection against unsafe reactor operation during steady-state and transient power operations. They initiate selected protective functions to mitigate the consequences of design basis events. This chapter relates the functional performance requirements, design bases, system descriptions, and safety evaluations for those systems. The safety evaluations show that the systems can be designed and built to conform to the applicable criteria, codes, and standards concerned with the safe generation of nuclear power.

Because of the rapid changes that are taking place in the digital computer and graphic display technologies employed in a modern human system interface, design certification of the AP1000 focuses upon the process used to design and implement instrumentation and control systems for the AP1000, rather than on the specific implementation. The design specifics provided here are included as an example for illustration.

DCD Chapter 7 for the AP1000 has been written to permit the use of either the Eagle protection system hardware described in the AP600 DCD or the Common Qualified Platform (Common Q) described in References 8 and 13 and accepted in References 11, 14, and 16. The I&C functional requirements of the AP600, which has received Design Certification, have been retained to the maximum extent compatible with the Common Q hardware and software and the Eagle hardware and software.

The terminology used for Chapter 7 is intended to be independent of any product, but when this is not possible, Common Q terminology is used.

This chapter also discusses the instrumentation portions of the safety-related systems which function to achieve the system responses assumed in the accident analysis, and those needed to shutdown the plant. Section 7.1 describes the AP1000 instrumentation and control architecture, with specific emphasis on the protection and safety monitoring system. The plant control system is discussed briefly. Other systems are discussed in more detail in relevant sections or chapters. Section 7.2 discusses the reactor trip function, and Section 7.3 addresses the engineered safety features (ESF). Systems required for safe shutdown are discussed in Section 7.4 in support of other chapters. Safety-related display instrumentation is discussed in Section 7.5 and interlocks important to safety are presented in Section 7.6. Control systems and the diverse actuation system are discussed in Section 7.7.

Definitions

Terminology used in this chapter reflects an interdisciplinary approach to safety-related systems similar to that proposed in IEEE 603 (Reference 1).

Safety System – The aggregate of electrical and mechanical equipment necessary to mitigate the consequences of design basis events.

Protection and Safety Monitoring System – The aggregate of electrical and mechanical equipment which senses generating station conditions and generates the signals to actuate reactor trip and ESF, and which provides the equipment necessary to monitor plant safety-related functions during and following designated events.

Protective Function – Any one of the functions necessary to mitigate the consequences of a design basis event. Protective functions are initiated by the protection and safety monitoring system logic and will be accomplished by the trip and actuation subsystems. Examples of protective functions are reactor trip and engineered safety features (such as valve alignment and containment isolation).

Actuated Equipment – The assembly of prime movers and driven equipment used to accomplish a protective function (such as solenoids, shutdown rods, and valves).

Actuation Device – A component that directly controls the motive power for actuated equipment (such as circuit breakers, relays, and pilot valves).

Division – One of the four redundant segments of the safety system. A division includes its associated sensors, field wiring, cabinets, and electronics used to generate one of the redundant actuation signals for a protective function. It also includes the power source and actuation signals.

Channel – One of the several separate and redundant measurements of a single variable used by the protection and safety monitoring system in generating the signal to initiate a protective function. A channel can lose its identity when it is combined with other inputs in a division.

Degree of Redundancy – The number of redundant channels monitoring a single variable, or the number of redundant divisions which can initiate a given protective function or accomplish a given protective function. Redundancy is used to maintain protection capability when the safety-related system is degraded by a single random failure.

System-Level Actuation – Actuation of a sufficient number of actuation devices to effect a protective function.

Component-Level Actuation – Actuation of a single actuation device (component).

7.1.1 The AP1000 Instrumentation and Control Architecture

Figure 7.1-1 illustrates the instrumentation and control architecture for the AP1000. The figure shows two major sections separated by the real-time data network.

The lower portion of the figure includes the plant protection, control, and monitoring functions. At the left is the protection and safety monitoring system. It performs the reactor trip functions, the engineered safety features (ESF) actuation functions, and the Qualified Data Processing (QDPS)

functions. The I&C equipment performing reactor trip and ESF actuation functions, their related sensors, and the reactor trip switchgear are, for the most part, four-way redundant. This redundancy permits the use of bypass logic so that a division or individual channel out of service can be accommodated by the operating portions of the protection system reverting to a two-out-of-three logic from a two-out-of-four logic.

The ESF coincidence logic performs system-level logic calculations, such as initiation of the passive residual heat removal system. It receives inputs from the plant protection subsystem bistables and the main control room.

The ESF actuation subsystems provide the capability for on-off control of individual safety-related plant loads. They receive inputs from the ESF coincidence logic, remote shutdown workstation and the main control room.

The plant control system performs nonsafety-related instrumentation and control functions using both discrete (on/off) and modulating (analog) type actuation devices.

The nonsafety-related real-time data network, which horizontally divides Figure 7.1-1, is a high speed, redundant communications network that links systems of importance to the operator. Safety-related systems are connected to the network through gateways and qualified isolation devices so that the safety-related functions are not compromised by failures elsewhere. Plant protection, control, and monitoring systems feed real-time data into the network for use by the control room and the data display and processing system.

The upper portion of the figure depicts the control rooms and data display and processing system. The main control room is implemented as a set of compact operator consoles featuring color graphic displays and soft control input devices. The graphics are supported by a set of graphics workstations that take their input from the real-time data network. An advanced alarm system, implemented in a similar technology, is also provided.

The data display and processing (plant computer) system is implemented in a distributed architecture. The working elements of the distributed computer system are graphics workstations, although their graphics capability is secondary to their computing performance. The distributed computer system obtains its input from the real-time data network and delivers its output over the network to other users.

WCAP-15775 (Reference 7) describes the diversity and defense-in-depth features of the AP1000 instrumentation and control architecture.

Protection and Safety Monitoring System

The protection and safety monitoring system provides detection of off-nominal conditions and actuation of appropriate safety-related functions necessary to achieve and maintain the plant in a safe shutdown condition. The protection and safety monitoring system controls safety-related components in the plant that are operated from the main control room or remote shutdown workstation.

In addition, the protection and safety monitoring system provides the equipment necessary to monitor the plant safety-related functions during and following an accident as required by Regulatory Guide 1.97.

Special Monitoring System

The special monitoring system does not perform any safety-related or defense-in-depth functions. The special monitoring system consists of specialized subsystems that interface with the instrumentation and control architecture to provide diagnostic and long-term monitoring functions.

The special monitoring system is the metal impact monitoring system. The metal impact monitoring system detects the presence of metallic debris in the reactor coolant system when the debris impacts against the internal parts of the reactor coolant system. The metal impact monitoring system is composed of digital circuit boards, controls, indicators, power supplies and remotely located sensors and related signal processing devices. The sensors and their related signal processing devices are mounted in pairs to maintain the impact monitoring function if a sensor fails in service. The metal impact monitoring system is described in subsection 4.4.6.4.

Plant Control System

The plant control system provides the functions necessary for normal operation of the plant from cold shutdown through full power. The plant control system controls nonsafety-related components in the plant that are operated from the main control room or remote shutdown workstation.

The plant control system contains nonsafety-related control and instrumentation equipment to change reactor power, control pressurizer pressure and level, control feedwater flow, and perform other plant functions associated with power generation. The plant control system is described in subsections 7.1.3 and 7.7.1.

Diverse Actuation System

The diverse actuation system is a nonsafety-related, diverse system that provides an alternate means of initiating reactor trip and actuating selected engineered safety features, and providing plant information to the operator. The diverse actuation system is described in subsection 7.7.1.11.

Operation and Control Centers System

The operation and control centers system includes the main control room, the technical support center, the remote shutdown workstation, emergency operations facility, local control stations and associated workstations for these centers. With the exception of the control console structures, the equipment in the control room is part of the other systems (for example, protection and safety monitoring system, plant control system, data display and processing system).

The boundaries of the operation and control centers system for the main control room and the remote shutdown workstation are the signal interfaces with the plant components. These interfaces are via the plant protection and safety monitoring system processor and logic circuits, which interface with the reactor trip and ESF plant components; the plant control system processor and

logic circuits, which interface with the nonsafety-related plant components; and the plant real-time data network, which provides plant parameters, plant component status, and alarms.

Data Display and Processing System

The data display and processing system provides the equipment used for processing data that result in nonsafety-related alarms and displays for both normal and emergency plant operations, generating these displays and alarms, providing analysis of plant data, providing plant data logging and historical storage and retrieval, and providing operational support for plant personnel.

The data display and processing system also contains the real-time data network, which is a redundant data highway that links the elements of the AP1000 instrumentation and control architecture.

Incore Instrumentation System

The primary function of the incore instrumentation system is to provide a three-dimensional flux map of the reactor core. This map is used to calibrate neutron detectors used by the protection and safety monitoring system, as well as to optimize core performance. A secondary function of the incore instrumentation system is to provide the protection and safety monitoring system with the thermocouple signals necessary for the post-accident inadequate core cooling monitor. The incore instrument assemblies house both fixed incore flux detectors and core exit thermocouples. The incore instrumentation system is described in subsection 4.4.6.1.

7.1.2 Protection and Safety Monitoring System

The protection and safety monitoring system is illustrated in Figure 7.1-2. The functions of the protection and safety monitoring system are implemented in separate processor-based subsystems. Each subsystem is located on an independent computer bus to prevent propagation of failures and to enhance availability. In most cases, each subsystem is implemented in a separate card chassis. Subsystem independence is maintained through the use of the following:

- Separate dc power sources for redundant subsystems with output protection to prevent interaction between redundant subsystems upon failure of a subsystem.
- Separate input or output circuitry to maintain independence at the subsystem interfaces.
- Deadman signals: A device, circuit, or function that forces a predefined operating condition upon the cessation of a normally dynamic input parameter to improve the reliability of hard-wired data that crosses the subsystem interface.
- Optical coupling or resistor buffering between two subsystems or between a subsystem and an input/output (I/O) module.

WCAP-13382 (Reference 2) provides a description of the Eagle hardware elements which comprise the protection and safety monitoring system configuration for the AP600. WCAP-14080 (Reference 4) provides a description of the Eagle software architecture and operation for the AP600. The Eagle hardware and software described for the AP600 may be used for the AP1000;

alternatively, the AP1000 protection and safety monitoring system may be based on the Common Qualified Platform described in References 8 and 13 and accepted in References 11, 14, and 16.

7.1.2.1 Plant Protection Subsystems

The plant protection subsystems contain the necessary equipment to perform the following functions:

- Permit acquisition and analysis of the sensor inputs required for reactor trip and ESF actuation calculations.
- Perform computation or logic operation on variables based on these inputs.
- Provide trip signals to the reactor trip switchgear and ESF actuation data to the ESF coincidence logic, as required.
- Permit manual trip or bypass of each individual automatic reactor trip function and permit manual actuation or bypass of each individual automatic ESF actuation function.
- Provide data to external systems.
- Provide redundancy for the reactor trips and ESF actuations.
- Provide isolation circuitry for control functions requiring input from sensors which are also required for protection functions.

Figure 7.1-3A illustrates the plant protection subsystems for the Eagle I&C architecture. Figure 7.1-3B illustrates the plant protection subsystems and the engineered safety features coincidence logic for the Common Q architecture.

7.1.2.1.1 Reactor Trip Functions

The reactor trip functions are performed in two subsystems per division for accident protection. The primary function of the reactor trip subsystems is to process input data and provide a partial trip signal to the trip logic whenever the preset limit of each protection function is exceeded.

To perform the protective function calculations, the subsystems require data from field sensors and manual inputs from the main control room. The results of the calculations drive the corresponding partial trip circuitry of the reactor trip coincidence logic.

The reactor trip coincidence logic acts to initiate a reactor trip when a trip function in two-out-of-four independent safety divisions is in a partial trip state. The reactor trip coincidence logic also provides for the bypass of trip functions and safety divisions to accommodate tests and maintenance. The overall system logic implemented by the reactor trip coincidence logic function is discussed in subsection 7.1.2.9.

The reactor trip coincidence logic is composed of two primary functions:

- The bistable processing function provides partial trip/bypass status to the other divisions.
- The reactor trip coincidence logic performs the logic to combine the partial trip signals and outputs a fail-safe trip signal to the reactor trip switchgear.

7.1.2.1.2 Reactor Trip Switchgear Interface

The final stage of the reactor trip coincidence logic provides the signal to energize the undervoltage trip attachment on each of the two division reactor trip switchgear breakers. Loss of the signal de-energizes the undervoltage trip attachments and results in the opening of the reactor trip breakers. An additional external relay is de-energized with the loss of the signal. The normally closed contacts of the relay energize the shunt trip attachments on each breaker at the same time that the undervoltage trip attachment is de-energized. The reactor trip switchgear interface, including the trip attachments and the external relay, are within the scope of the protection and safety monitoring system. Separate outputs are provided for each breaker.

Testing of the interface allows trip actuation of the breakers by either the undervoltage trip attachment or the shunt trip attachment.

Figure 7.1-4 illustrates the reactor switchgear and manual trip interface.

7.1.2.1.3 Manual Reactor Trip

A manual reactor trip can be accomplished from the main control room by redundant momentary switches. The switches directly interrupt the power from the voting logic, actuating the undervoltage and shunt trip attachments. Figure 7.1-4 illustrates the implementation of the manual reactor trip function.

7.1.2.2 Engineered Safety Features Coincidence Logic

The ESF logic functions are also performed in two subsystems per division for more reliable accident mitigation. The primary functions of the ESF coincidence logic are to process inputs, calculate actuations, combine the automatic actuation with the manual actuation and manual bypass data, and transmit the data to the ESF actuation subsystems. To perform the ESF logic calculations, the subsystems require data from the plant protection subsystems, and also use manual inputs from the main control room and the remote shutdown workstation.

The ESF coincidence logic performs the following functions:

- Receives bistable data supplied by the four divisions of the plant protection subsystems and performs two-out-of-four voting on this data.
- Implements system-level logic and transmits the output to the ESF actuation subsystems for ESF component actuation.

- Processes manual system-level actuation commands received from the main control room and remote shutdown workstation.

Figure 7.1-5 illustrates the engineered safety features coincidence logic for the Eagle I&C architecture. Figure 7.1-3B illustrates the plant protection subsystems and the engineered safety features coincidence logic for the Common Q architecture.

7.1.2.3 Engineered Safety Features Actuation Subsystems

The ESF actuation subsystems provide a distributed interface between the plant operator and the nonmodulating safety-related plant components. Nonmodulating control relates to the opening or closing of solenoid valves and solenoid pilot valves, and the opening or closing of motor-operated valves and dampers. The ESF actuation subsystems implement criteria established by the fluid systems designers for permissive and interlock logic applied to the component actuations. It also provides the plant operator with information on the equipment status, such as indication of component position (full closed, full open, valve moving), component control modes (manual, automatic, local, remote) or abnormal operating condition (power not available, failure detected).

The ESF coincidence logic performs the appropriate voting operation on the bistable signals and generates the system-level ESF logic commands including the system-level manual commands. These system-level actuations are then sent to the ESF actuation subsystems. The ESF actuation subsystems decode the system commands and actuate the final equipment through the interlocking logic specific to each component. Component-level actuation signals are sent from the main control room to the ESF actuation subsystems over redundant data highways. Component status is transmitted from the ESF actuation subsystems to the main control room over the same redundant data highways. Those components used for safe shutdown can also be controlled from the remote shutdown workstation.

Figure 7.1-6 shows this redundant data highway for a single safety division for the Eagle I&C architecture. Figure 7.1-3B includes the communication between the engineered safety features coincidence logic and the engineered safety features actuation logic for the Common Q architecture. Figure 7.1-9A illustrates the engineered safety features actuation logic for the Eagle I&C architecture. Figure 7.1-9B illustrates the engineered safety features actuation logic for the Common Q architecture.

7.1.2.4 Reactor Trip Switchgear

The reactor trip switchgear is used to initiate reactor shutdown. The reactor trip switchgear connects the electrical motive power, supplied from motor-generator sets, to the rod control system. The rod control system holds the control rods in position as long as electrical power is available. When the protection and safety monitoring system senses that established limits for safe operation of the plant have been, or are about to be, exceeded, a command is generated to de-energize the undervoltage trip device and energize the shunt trip device in the reactor trip switchgear breakers. This trips the breakers, disconnecting the power to the rod control system. When power is removed, the control rods drop by gravity into the reactor core, initiating the shutdown process.

The reactor trip switchgear is the final element in the protection and safety monitoring system which operates for reactor trip. There are four redundant safety divisions, with each division containing two circuit breakers of the reactor trip switchgear (eight breakers total). As illustrated in Figure 7.1-7, the eight circuit breakers are arranged in a two-out-of-four logic configuration. The reactor trip switchgear includes associated or ancillary equipment and internal busbars. Breaker cells have steel barriers to completely encapsulate a breaker within its division and to provide physical separation between the breakers in different divisions.

7.1.2.5 Qualified Data Processing Subsystems

The Qualified Data Processing Subsystem (QDPS), a subsystem of the PMS, provides safety-related display of selected parameters in the control room.

The QDPS subsystems are a redundant configuration consisting of sensors, QDPS hardware, and qualified displays.

The qualified data processing subsystems perform the following functions:

- Provide safety-related data processing and display
- Provide the operator with sufficient operational data to safely shut the plant down in the event of a failure of the other display systems
- Provide qualified and nonqualified data to the real-time data network for use by other systems in the plant
- Process data for main control room display, and to meet Regulatory Guide 1.97 requirements
- Provide data to the main control room, the remote shutdown workstation, the plant computer, other nonsafety-related devices, and nonqualified emergency response facilities in conformance with NUREG-0696

The QDPS hardware consists of safety-related modular data gathering units. The QDPS receives inputs from process sensors and safety-related digital systems. The QDPS consolidates the input data, performs conversions to process units, and formats the data for data link transmission.

Figure 7.1-8A illustrates the qualified data processing subsystem for the Eagle I&C architecture. Figure 7.1-8B illustrates the qualified data processing subsystem for the Common Q architecture.

Power is provided to the QDPS from the Class 1E dc and UPS system for 72 hours after a loss of all ac power (station blackout). After 72 hours, the ancillary diesel generators provide power for the QDPS. The QDPS is a two-train subsystem (Divisions B and C). The PMS, including the QDPS, is diverse from the Diverse Actuation System (DAS). Sensors are not shared between PMS and DAS.

The RTS/ESFAS signals are processed by the Plant Protection Subsystem of the PMS. Within the PMS, some sensors are shared between the Plant Protection Subsystem and QDPS. Shared sensors are processed first by the QDPS because the QDPS will need this sensor for more than 24 hours

following a station blackout. Twenty-four-hour batteries power the Plant Protection Subsystem; therefore, the Plant Protection Subsystem cannot be used for QDPS functions.

The typical input parameter for RTS/ESFAS is four-way redundant with one sensor for each of the four divisions. If that parameter is also needed by QDPS, the B and C division sensors are processed first by QDPS then sent to the Plant Protection Subsystem. The A and D division sensors are not shared with QDPS and, thus, are processed directly by the Plant Protection Subsystem. If an RTS/ESFAS parameter is not needed by QDPS or if it is not needed after 24 hours, it is processed directly by the Plant Protection Subsystem in all four divisions.

7.1.2.6 Main Control Room Multiplexers

The protection and safety monitoring system contains redundant multiplexers to provide a signal path from the protection channels to safety operator modules in the main control room. One redundant main control room multiplexer is associated with each of the four safety divisions. The multiplexers provide for transmission of component-level manual actuation signals from the main control room to the ESF actuation subsystems. The multiplexers also provide for transmission of component status information from the ESF actuation subsystems to the main control room.

The multiplexers communicate with soft control devices or operator interface modules in the main control room. Subsection 7.1.3.3 provides additional discussion of the operation of the soft control devices. The transfer of control from the main control room to the remote shutdown workstation is accomplished using transfer switches as described in subsection 7.4.3.

Various “handshaking” signals are implemented for requests and responses between the soft controls and the multiplexers to verify the receipt and the validity of the messages.

7.1.2.7 Sensors

The protection and safety monitoring system monitors key variables related to equipment mechanical limitations, and variables directly affecting the heat transfer capability of the reactor. Some limits, such as the overtemperature ΔT setpoint, are calculated in the plant protection subsystem from other parameters because direct measurement of the variable is not possible. This subsection provides a description of the sensors which monitor the variables for the protection and safety monitoring system. For convenience the discussions are grouped into the following three categories:

- Process sensors
- Nuclear instrumentation detectors
- Status inputs from field equipment

The inputs described are those required to generate the initiation signals for the protective functions. The use of each parameter is discussed in the sections that deal with each protective function. For example, reactor trip is discussed in Section 7.2 and ESF actuation is described in Section 7.3.

7.1.2.7.1 Process Sensors

The process sensors are devices which measure temperature, pressure, fluid flow, and fluid level. Process instrumentation excludes nuclear and radiation measurements.

Additional information on these process variables is included as part of the description of each process system provided in other chapters. The process variables measured by the protection and safety monitoring system are listed in Sections 7.2, 7.3, and 7.5.

7.1.2.7.2 Nuclear Instrumentation Detectors

Three types of neutron detectors are used to monitor the leakage neutron flux from a completely shutdown condition to 120 percent of full power. The power range channels are capable of measuring overpower excursions up to 200 percent of full power.

The lowest range (source range) covers six decades of leakage neutron flux. The lowest observed count rate depends on the strength of the neutron sources in the core and the core multiplication associated with the shutdown reactivity. This generally is greater than two counts per second. The next range (intermediate range) covers eight decades. Detectors and instrumentation are chosen to provide overlap between the higher portion of the source range and the lower portion of the intermediate range. The highest range of instrumentation (power range) covers approximately two decades of the total instrumentation range. This is a linear range that overlaps the higher portion of the intermediate range. The neutron detectors are installed in tubes located around the reactor vessel in the primary shield. Detector types for these three ranges are:

- Source range – proportional counter or pulse fission chamber
- Intermediate range – pulse fission chamber
- Power range – uncompensated ionization chamber

7.1.2.7.3 Equipment Status Inputs

Some inputs to the protection system are not measurements of process or nuclear variables, but are discrete indications of the status of certain equipment. Examples include manual switch positions, contact status inputs, and indications provided by valve limit switches.

7.1.2.8 Communication Functions

The communication functions provide information from the plant protection subsystem, the ESF coincidence logic, the ESF actuation subsystems, and the QDPS subsystems to external systems. This includes outputs to the plant control system and the data display and processing system. Isolation devices provide electrical isolation between the protection and safety monitoring system and the external systems. The communication functions also provide soft control information from the nonsafety system to the safety system for operator-initiated actuation and component control.

The communication functions are accomplished via channelized gateways as shown in Figure 7.1-1.

The PMS Gateway interfaces the safety PMS to the nonsafety real-time data network, which supports the remainder of the instrumentation and control system. The Gateway has two subsystems. One is the safety subsystem that interfaces to the Plant Protection Subsystem, the Engineered Safety Features Coincidence Logic, and the Qualified Data Processing Subsystem. The other is the nonsafety subsystem that interfaces to the real-time data network. The two subsystems are connected by a fiber-optic link that provides electrical isolation.

The primary flow of information between the two Gateway subsystems is from the safety subsystem to the nonsafety subsystem. This information is a combination of plant process parameter values and equipment status information. The information that flows from the nonsafety subsystem to the safety subsystem is limited to the following:

- The safety and nonsafety subsystems exchange periodic low-level interface signals that the communication controllers at each end of the link use to ensure that the link is functioning properly. These signals are used only by the communication controllers and are not propagated to the rest of the safety system. There is no application function in the safety system that uses this information.

- The main control room and the remote shutdown workstation operator consoles are nonsafety. The soft control inputs to the PMS from these locations are provided from the nonsafety subsystem to the safety subsystem of the Gateway.

The gateway provides both electrical and communication isolation between the nonsafety systems and the PMS. Other than the isolation function, the gateway is not required for any PMS safety function. There is no potential signal from the nonsafety system than will prevent the PMS from performing its safety functions.

Specifically, the Gateway will provide the following isolation features:

- Electrical isolation between the Class 1E and non-Class 1E ports of the Gateway, as required by IEEE 603-1991 (Reference 1).

- Communication isolation between the Class 1E and non-Class 1E ports of the Gateway, as envisioned by IEEE 7-4.3.2-1993, Annex G (Reference 15). This includes:

  - Class 1E communications buffering circuits to process the low-level interface signals.

  - Use of only simple connectionless protocols between the Class 1E and non-Class 1E ports of the Gateway. (Connectionless protocols do not use connection establishment/management/termination nor do they use acknowledgements/ negative-acknowledgements/retransmission.)

  - Software within the Class 1E portion of the gateway will filter the incoming message stream and accept only valid soft control commands from a predefined list of valid commands. All other messages will be discarded.

Application software running in the safety system will ensure the functional independence of the Class 1E functions from the soft control demands received from the nonsafety systems.

Specifically, the application software will provide the following features:

- In cases where a component is controlled by an automatic safety function, the PMS application software will ensure that the automatic safety function and the Class 1E soft controls both have priority over the non-Class 1E soft controls.

- In cases where a Class 1E component is not controlled by an automatic safety function, the PMS application software will ensure that the Class-1E controls have priority over the non-Class 1E soft controls.

Analog inputs required for both control and protection functions are processed independently with separate input circuitry. The input signal is classified as safety-related and is, therefore, isolated in the protection and safety monitoring system cabinet before being sent to the control system.

The plant protection and safety monitoring system also provides data to the plant control system pertaining to signals calculated in the subsystems, and to the data display and processing system.

Non-process signals are also provided to external systems. The non-process outputs inform the external systems of cabinet entry status, cabinet temperature, dc power supply voltages, and subsystem diagnostic status. Cabinet temperature sensing does not affect the safety-related function. The information is gathered for the sole purpose of analysis by external systems.

7.1.2.9 Fault Tolerance, Maintenance, Test, and Bypass

The protection and safety monitoring system provides a high degree of reliability and fault tolerance. This capability is demonstrated by the following design features:

- Two-out-of-four coincidence logic on reactor trip and most ESF actuations provides that any failure in a single protection channel or safety division cannot cause a spurious reactor trip or spurious system-level ESF actuation. This same two-out-of-four logic also provides that any failure in a single protection channel or safety division cannot prevent a required reactor trip or system level ESF actuation from occurring. This provides tolerance against failures ranging from the failure of a single instrument or component, to the complete failure of an entire plant protection subsystem or ESF coincidence logic division.

- Reactor trip and ESF actuation logic reverts to two-out-of-three coincidence logic if one channel is bypassed or in test. The protection and safety monitoring system logic does not allow more than one channel to be placed in bypass simultaneously. Therefore a single failure while in test cannot cause a spurious reactor trip or spurious system-level ESF actuation. This same two-out-of-three logic also provides that any failure in a single protection channel or safety division cannot prevent a required reactor trip or system-level ESF actuation from occurring.

  The bypass logic allows the system to meet the single failure criterion with one channel bypassed for testing or maintenance.

- The reactor trip logic provided in the plant protection subsystem also processes the manual system-level inputs involved in the reactor trip function. Section 7.2 provides further detail of the manual trip function. The voting logic for reactor trip functions is contained within each plant protection subsystem. The reactor trip breakers operate on a de-energize-to-trip principle.

- ESF actuation logic is performed redundantly in the ESF coincidence logic. Redundant subsystems perform this logic so that a component failure related to one subsystem cannot affect the other redundant subsystem. The system-level actuation outputs are transmitted to the ESF actuation subsystems. A single failure cannot prevent ESF actuation. Extensive error checking is performed to minimize failures from causing spurious actuation.

- Component-level logic is performed within the ESF actuation hardware. The logic processors are programmed to respond to actuation signals received from the protection and safety monitoring system data highways. Failure of one data highway does not prevent component-level actuations. Extensive error checking on the data highways is provided to minimize data highway failures from generating spurious ESF component-level actuations.

During maintenance, these same features that provide for fault tolerance allow the system to continue to operate with one channel or certain components out of service.

7.1.2.10 Isolation Devices

Isolation devices are used to maintain the electrical independence of divisions, and to prevent interaction between nonsafety-related systems and the safety-related system.

Isolation devices are incorporated into selected interconnections to maintain division independence. Isolation devices serve to prevent credible faults (such as open circuits, short circuits, or applied credible voltages) in one circuit from propagating to another circuit.

7.1.2.11 Test Subsystem

The test subsystem provides a means of testing the operation of the protection and safety monitoring system and verifying that the plant protection system setpoints are within the system requirements. Each redundant subsystem is tested individually.

Testing from the sensor inputs of the protection and safety monitoring system through to the actuated equipment is accomplished through a series of overlapping sequential tests with the majority of the tests capable of being performed with the plant at full power. Where testing final equipment at power would upset plant operation or damage equipment, provisions are made to test the equipment at reduced power or when the reactor is shut down.

Each division of the protection and safety monitoring system is furnished with a test subsystem. The test subsystem provides for verification of the accuracy of setpoints and other constants, and verification that proper signals appear at other locations in the system.

Verification of the signal processing algorithms is made by exercising the test signal sources (either by hardware or software signal injection) and observing the results up to, and including,

the attainment of a channel partial trip or actuation signal at the power interface. When required for the test, the tester automatically places the voting logic associated with the channel function under test in bypass.

The overlapping test sequence continues by inputting digital test signals at the output side of the threshold functions, in combinations necessary to verify the voting logic. Some of the input combinations to the coincidence logic cause outputs such as reactor trips and ESF initiation. The reactor trip circuit breakers are arranged in a two-out-of-four logic configuration, such that the tripping of the two circuit breakers associated with one division does not cause a reactor trip. This circuit breaker arrangement is illustrated in Figure 7.1-7. To reduce wear on the breakers through excessive tripping, and to avoid a potential plant trip resulting from a single failure while testing is in progress, the test sequence is designed so that actual opening of the trip breakers is only required when the breaker itself is being tested.

The test subsystem does not test the ESF actuators. This portion of the test may be accomplished by using component-level actuation signals. For those final devices that can be operated at power, without upsetting the plant or damaging equipment, the test is performed by actuating the manual actuation control which causes the device to operate. Position switches on the device itself send a signal back to the ESF actuation subsystem, where it is transmitted to the main control room for display purposes. The display verifies that the manual command is successfully completed, thus verifying operability of the final device. For those devices which cannot be tested at power without damage or upsetting the plant, continuity of the wiring up to the actuation device is verified. Operability of the final equipment is demonstrated at reduced power or at shutdown, depending on the equipment.

In addition to the testing function, the tester subsystem monitors the failure and diagnostic information from the subsystems during normal operation, thus enhancing system maintenance of the protection system.

The test subsystem provides the operator interface used for testing and maintenance.

Figure 7.1-5 includes the test subsystem for the Eagle I&C architecture. Figure 7.1-11 illustrates the test subsystem for the Common Q architecture.

7.1.2.12 Safety-Related Display Instrumentation

Safety-related display instrumentation provides the operator with information to determine the effect of automatic and manual actions taken following reactor trip due to a Condition II, III, or IV event as defined in Chapter 15. This instrumentation also provides for operator display of the information necessary to meet Regulatory Guide 1.97. A description of the equipment used to provide this function is provided in subsection 7.1.2.5. A description of the data provided to the operator by this instrumentation is provided in Section 7.5.

7.1.2.13 Auxiliary Supporting Systems

The safety-related system equipment is supported by the supply of uninterruptible electrical power. This electrical power is supplied by the Class 1E dc and UPS system discussed in Chapter 8.

7.1.2.14 Verification and Validation

[*Adequacy of the hardware and software is demonstrated for the protection and safety monitoring system through a verification and validation (V&V) program. Details on the verification and validation program are provided in either WCAP-13383 (Reference 3) or CE-CES-195 (Reference 9).*]* WCAP-13383 is an AP600 reference. CE-CES-195 is a Common Q document. The software development process is consistent with the following standards:

- ANSI/IEEE ANS-7-4.3.2-1993; "IEEE Standard Criteria for Digital Computers in Safety Systems of Nuclear Power Generating Stations"
- IEEE 828-1990; "IEEE Standard for Software Configuration Management Plans"
- IEEE 829-1983; "IEEE Standard for Software Test Documentation"
- IEEE 830-1993; "Recommended Practice for Software Requirements Specifications"
- IEEE 1012-1986; "IEEE Standard for Software Verification and Validation Plans"
- IEEE 1028-1988; "IEEE Standard for Software Reviews and Audits"
- IEEE 1042-1987; "IEEE Guide to Software Configuration Management"

7.1.2.14.1 Design Process

[*WCAP-13383 provides a planned design process for hardware and software development during the following life cycle stages:*

- *Design requirements phase*
- *System definition phase*
- *Hardware and software development phase*
- *System test phase*
- *Installation phase*

WCAP-15927 (Reference 10), a Common Q document, also provides a planned design process for hardware and software development during similar life cycle stages:

- *Conceptual phase*
- *System definition phase*
- *Software design phase*
- *Hardware design phase*
- *Software implementation phase*
- *Hardware implementation phase*
- *System integration phase*
- *Installation phase*

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Depending on the protection and safety monitoring system hardware used for AP1000, either WCAP-13383 or WCAP-15927 describe design processes that will be used for AP1000.]*

7.1.2.14.2 Commercial Dedication

[*WCAP-13383 (Reference 3) and CENPD-396-P (Reference 8) provide for the use of commercial off-the-shelf hardware and software through a commercial dedication process.*]* Control of the hardware and software during the operational and maintenance phase is the responsibility of the Combined License applicant as described in subsection 13.5.1.

7.1.3 Plant Control System

The plant control system is a nonsafety-related system that provides control and coordination of the plant during startup, ascent to power, power operation, and shutdown conditions. The plant control system integrates the automatic and manual control of the reactor, reactor coolant, and various reactor support processes for required normal and off-normal conditions. The plant control system also provides control of the nonsafety-related decay heat removal systems during shutdown. The plant control system accomplishes these functions through use of the following:

- Rod control
- Pressurizer pressure and level control
- Steam generator water level control
- Steam dump (turbine bypass) control
- Rapid power reduction

The plant control system provides automatic regulation of reactor and other key system parameters in response to changes in operating limits (load changes). The plant control system acts to maximize margins to plant safety limits and maximize the plant transient performance. The plant control system also provides the capability for manual control of plant systems and equipment. Redundant control logic is used in some applications to increase single-failure tolerance.

The plant control system includes the equipment from the process sensor input circuitry through to the modulating and nonmodulating control outputs as well as the digital signals to other plant systems. Modulating control devices include valve positioners, pump speed controllers, and the control rod equipment. Nonmodulating devices include motor starters for motor-operated valves and pumps, breakers for heaters, and solenoids for actuation of air-operated valves. The plant control system cabinets contain the process sensor inputs and the modulating and nonmodulating outputs. The plant control system also includes equipment to monitor and control the control rods.

The functions of the plant control system are performed by system assemblies including:

- Distributed controllers
- Signal selector algorithms
- Operator controls and indication
- Real-time data network
- Rod control system

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

- Rod position indication
- Rod drive motor-generator sets

Figure 7.1-10 provides an illustration of the plant control system.

7.1.3.1 Distributed Controllers

Each distributed controller processes inputs, performs system-level and component-level control calculations, provides capability for an operator interface to the controlled components, transmits control signals to discrete, modulating, and networked interfaced control components, and provides plant status and plant parameter information to the real-time data network.

The distributed controllers receive process inputs and implement the system-level logic and control algorithms appropriate for the plant operating mode. The distributed controllers receive process inputs from, and transmit process control outputs to, the actuated components. The distributed controller also transmits and receives process signals via the real-time data network. The real-time data network also provides for two-way communication between the distributed controllers and between the distributed controllers and the main control room and remote shutdown workstation.

Control functions are distributed across multiple distributed controllers so that single failures within a controller do not degrade the performance of control functions performed by other controllers. The major control functions which are implemented in different distributed controllers include reactor power control, feedwater control, pressurizer control, and turbine control.

7.1.3.2 Signal Selector Algorithms

Signal selector algorithms provide the plant control system with the ability to obtain inputs from the protection and safety monitoring system. The signal selector algorithms select those protection system signals that represent the actual status of the plant and reject erroneous signals. Therefore, the control system does not cause an unsafe control action to occur even if one of four redundant protection channels is degraded by random failure simultaneous with another of the four channels bypassed for test or maintenance.

Each signal selector algorithm receives data from each of the redundant divisions of the protection and safety monitoring system. The data is received from each division through an isolation device.

The signal selector algorithms provide validated process values to the plant control system. They also provide the validation status, the average of the valid process values, the number of valid process values, an alarm (if one process value has been rejected), and another alarm (if two process values have been rejected).

For the logic values received from the protection and safety monitoring system, such as permissives, the signal selector algorithms perform voting on the logic values to provide a valid logic value to the plant control system. They also provide the validation status, the number of valid logic values, an alarm if one logic value differs from the voted value, and another alarm if two logic values differ from the voted value.

7.1.3.3 Operator Controls and Indication

The plant control operator interface is a set of soft control devices that replace conventional switch/light or potentiometer/meter assemblies used for operator interface with control systems. These soft control devices provide consistent operator interfaces for the plant control system. The soft controls are located on each operator workstation and the remote shutdown workstation. Each soft control device can control safety-related and nonsafety-related equipment.

The implementation of the soft controls is consistent with the following functional requirements:

- The soft control function does not affect the electrical or functional isolation of the safety-related and nonsafety-related equipment. This isolation is maintained upon a single failure of any equipment performing or supporting the soft control function.

- Failure of the operator displays does not prevent an operator from being able to safely shutdown the plant.

When the operator desires to operate a component, the graphical operator display which is indicating the component status is presented on the operator control console. This results in a message being sent to the soft control device. The soft control device then displays the appropriate control template. The operator then selects the desired control action on the template. After the operator verifies that the desired control action is properly selected, the operator then actuates the control action, causing the selected control action to be transmitted to the control device.

7.1.3.4 Real-Time Data Network

The real-time data network is a redundant data highway that supports both periodic and aperiodic data transfers of nonsafety-related signals and data. Periodic transfers consist of process data that is broadcast over the network at fixed intervals and is available to all destinations. Aperiodic data transfer is generally used for messages or file transfers.

The real-time data network provides communications among the distributed controllers, the plant protection and safety monitoring system gateways, the incore instrumentation, and the special monitoring system.

7.1.3.5 Rod Control System

The primary means of regulating the reactor power and power distribution is to position clusters of control rods in the reactor core using the rod control system.

The control rods are moved into and out of the reactor core by means of electromagnetic jacking mechanisms, called control rod drive mechanisms, located on the reactor vessel head. Each control rod drive mechanism consists of two gripper mechanisms, one stationary and one movable, that hold a notched driveline attached to the upper end of the control rod. The grippers and the lift armature are controlled by coils mounted external to the mechanism, concentric with the rod driveline. By controlling the sequence of energizing these coils, the mechanism can be made to step into, or out of, the reactor in increments. The rod control equipment provides this sequence control.

The control rods are arranged into symmetrical groups. The groups of control rods are divided into two categories: shutdown rods that are normally held fully withdrawn from the reactor, and control rods that are positioned to some intermediate insertion. In addition, there is a subcategory of control rods (low worth gray rods). If a rapid shutdown is necessary, the control, shutdown, and gray rods are dropped into the reactor by de-energizing their drive mechanisms.

Interlocks are provided to prevent the motion of the control rods outside of planned sequences.

7.1.3.6 Rod Position Indication

The position of each control rod is continuously monitored by the rod position indication system. This information is detected by the rod position detector assemblies. The signals from the detectors are processed by the data cabinets and transmitted to the distributed controllers. The distributed controllers further processes the rod position information and transmits this information to the real-time data network.

7.1.3.7 Rod Drive Motor-Generator Sets

The rod drive motor-generator sets provide the power to the control rod drive mechanisms through the reactor trip switchgear. The rod drive motor-generator sets are included in the plant control system. The safety-related reactor trip switchgear is included in the plant protection and safety monitoring system.

There are two motor-generator sets with flywheels and one control cabinet. Each motor-generator is a three-phase induction motor, direct-coupled to a flywheel, and a synchronous alternator.

During normal operating conditions, both motor generator sets are operating in parallel and equally sharing the total load demand. Each motor-generator set is capable of supplying the entire load requirements when the other set is out of service.

7.1.4 Identification of Safety Criteria

7.1.4.1 Conformance of the Safety System Instrumentation to Applicable Criteria

The safety-related system instrumentation described in subsection 7.1.1 is designed and built to conform to the applicable criteria, codes, and standards concerned with the safe generation of nuclear power. Applicable General Design Criteria are listed in Section 3.1, NRC Regulatory Guides in subsection 1.9.1, and Branch Technical Positions in subsection 1.9.2. Industry Standards are cited as references.

The instrumentation and control portion of the safety-related system meets the requirements of IEEE 603-1991 as discussed in WCAP-15776 (Reference 12). The topics are listed in the same order as they appear in Sections 4 through 8 of IEEE 603-1991. IEEE 603 provides the design bases of the instrumentation and control portion of the safety system. Other criteria related to the IEEE 603-1991 requirements are also identified.

7.1.4.2 Conformance With Industry Standards

The instrumentation and control systems are designed in accordance with guidance provided in applicable portions of the following standards. The portions of the standards which are considered to be applicable are the portions of the standards which apply to instrumentation and control systems performing protection and control functions in an industrial environment:

- IEEE 323-1974; "IEEE Standard for Qualifying Class IE Equipment for Nuclear Power Generating Stations"
- IEEE 344-1987; "IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations"
- IEEE 379-2000; "IEEE Standard Application of the Single-Failure Criterion to Nuclear Power Generating Station Safety Systems"
- IEEE 383-1974; "IEEE Standard for Type Test of Class IE Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations"
- IEEE 384-1981; "IEEE Standard Criteria for Independence of Class 1E Equipment and Circuits"
- IEEE 420-1982; "IEEE Standard for the Design and Qualification of Class 1E Control Boards, Panels, and Racks Used in Nuclear Power Generating Stations"
- IEEE 603-1991; "IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations"
- IEEE 627-1980; "IEEE Standard for Design Qualification of Safety Systems Equipment Used in Nuclear Power Generating Stations"
- IEEE 1050-1996; "IEEE Guide for Instrumentation and Control Equipment Grounding in Generating Stations"
- IEEE 1074-1995; "IEEE Standard for Developing Software Life Cycle Processes"
- EPRI TR-102323, Revision 1, "Guidelines for Electromagnetic Interference Testing in Power Plants"

7.1.5 AP1000 Protective Functions

Protective functions are those necessary to achieve the system responses assumed in the safety analyses, and those needed to shut down the plant safely. The protective functions are grouped into two classes, reactor trip and ESF actuation. The software associated with these functions is considered a basic component as defined in 10 CFR 21 (Reference 6).

Reactor trip is discussed in Section 7.2. ESF actuation is discussed in Section 7.3.

7.1.6 Combined License Information

Combined License applicants referencing the AP1000 certified design will provide a calculation of setpoints for protective functions consistent with the methodology presented in Reference 5. Reference 5 is an AP600 document that describes a methodology that is applicable to AP1000. AP1000 has some slight differences in instrument spans.

Combined License applicants referencing the AP1000 certified design will provide resolution for generic open items and plant-specific action items resulting from NRC review of the I&C platform. This will include definition of a methodology for overall response time testing.

7.1.7 References

1. IEEE 603-1991, "IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations."

2. WCAP-13382 (Proprietary) and WCAP-13391 (Non-Proprietary), "AP600 Instrumentation and Control Hardware Description," May 1992.

[*3. WCAP-13383, Revision 1 (Non-Proprietary), "AP600 Instrumentation and Control Hardware and Software Design, Verification, and Validation Process Report," June 1996.*]*

4. WCAP-14080 (Proprietary) and WCAP-14081 (Non-Proprietary), "AP600 Instrumentation and Control Software Architecture and Operation Description," June 1994.

[*5. WCAP-14605 (Proprietary) and WCAP-14606 (Non-Proprietary), "Westinghouse Setpoint Methodology for Protection Systems, AP600," April 1996.*]*

6. 10 CFR 21, "Reporting of Defects and Noncompliance."

7. WCAP-15775, Revision 2, "AP1000 Instrumentation and Control Defense-in-Depth and Diversity Report," March 2003.

[*8. CENPD-396-P, Rev. 01 (Proprietary), "Common Qualified Platform," May 2000 and WCAP-16097-NP-A (Non-Proprietary), May 2003.*]*

[*9. CE-CES-195, Rev. 01, "Software Program Manual for Common Q Systems," May 26, 2000.*]*

[*10. WCAP-15927, Rev. 0, "Design Process for AP1000 Common Q Safety Systems," August 2002.*]*

11. ML003740165, "Acceptance for Referencing of Topical Report CENPD-396-P, Rev. 01, 'Common Qualified Platform' and Appendices 1, 2, 3 and 4, Rev. 01 (TAC No. MA1677)," August 11, 2000.

12. WCAP-15776, "Safety Criteria for the AP1000 Instrument and Control Systems," April 2002.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

13. CENPD-396-P, Appendix 4, Rev. 02 (Proprietary), "Common Qualified Platform Integrated Solution," April 2001 and WCAP-16097-NP-A, Appendix 4 (Non-Proprietary), May 2003.

14. ML011690170, "Safety Evaluation for the Closeout of Several of the Common Qualified Platform Category 1 Open Items Related to Reports CENPD-396-P, Revision 1 and CE-CES-195, Revision 1 (TAC No. MB0780)," June 22, 2001.

15. IEEE 7-4.3.2-1993, "IEEE Standard Criteria for Digital Computers in Safety Systems of Nuclear Power Generating Stations."

16. ML0305507760, "Acceptance of the Changes to Topical Report CENPD-396-P, Rev. 01, 'Common Qualified Platform,' and Closeout of Category 2 Open Items (TAC No. MB2553)," February 24, 2003.

[This page intentionally blank]

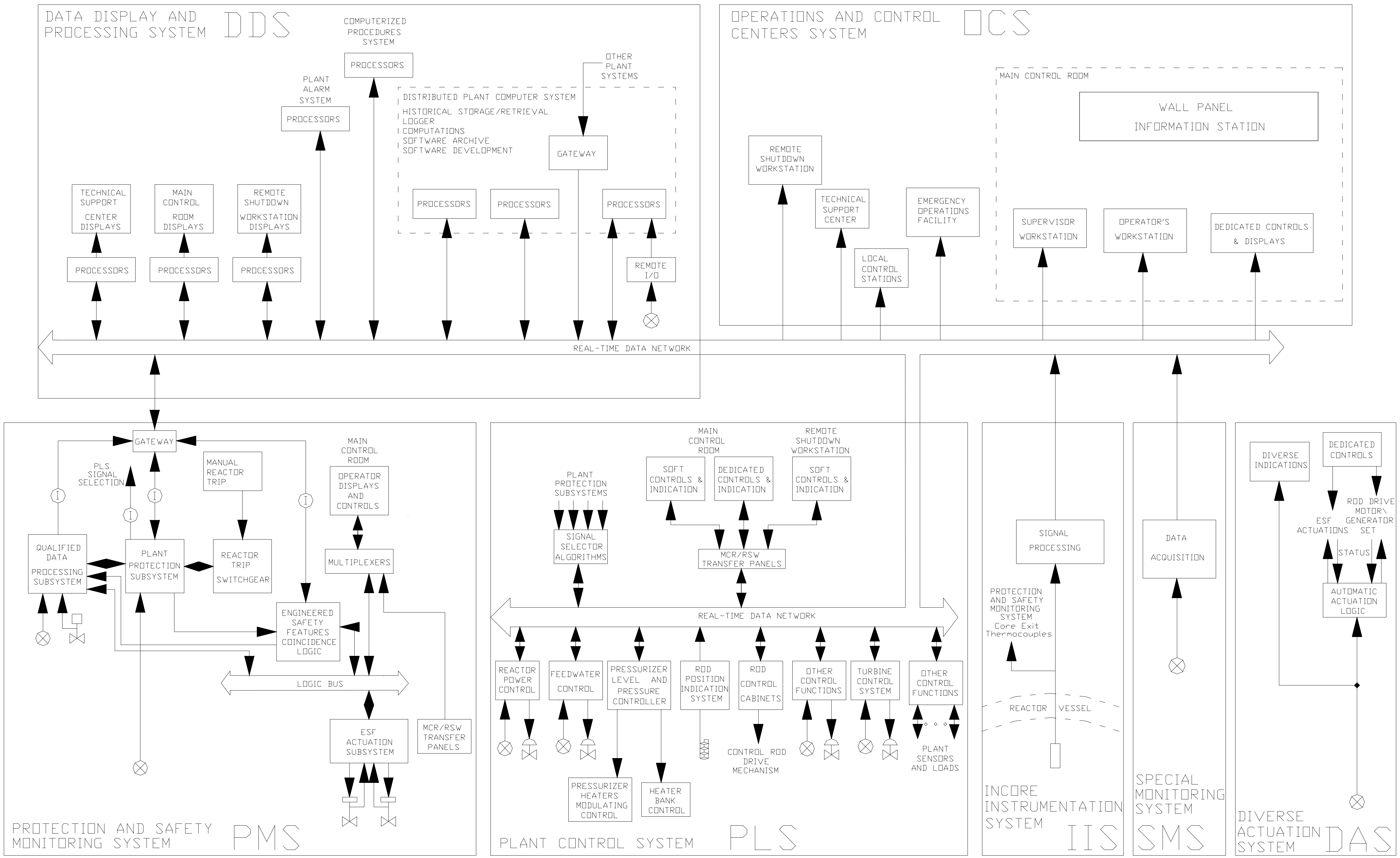


Figure 7.1-1

Instrumentation and Control Architecture

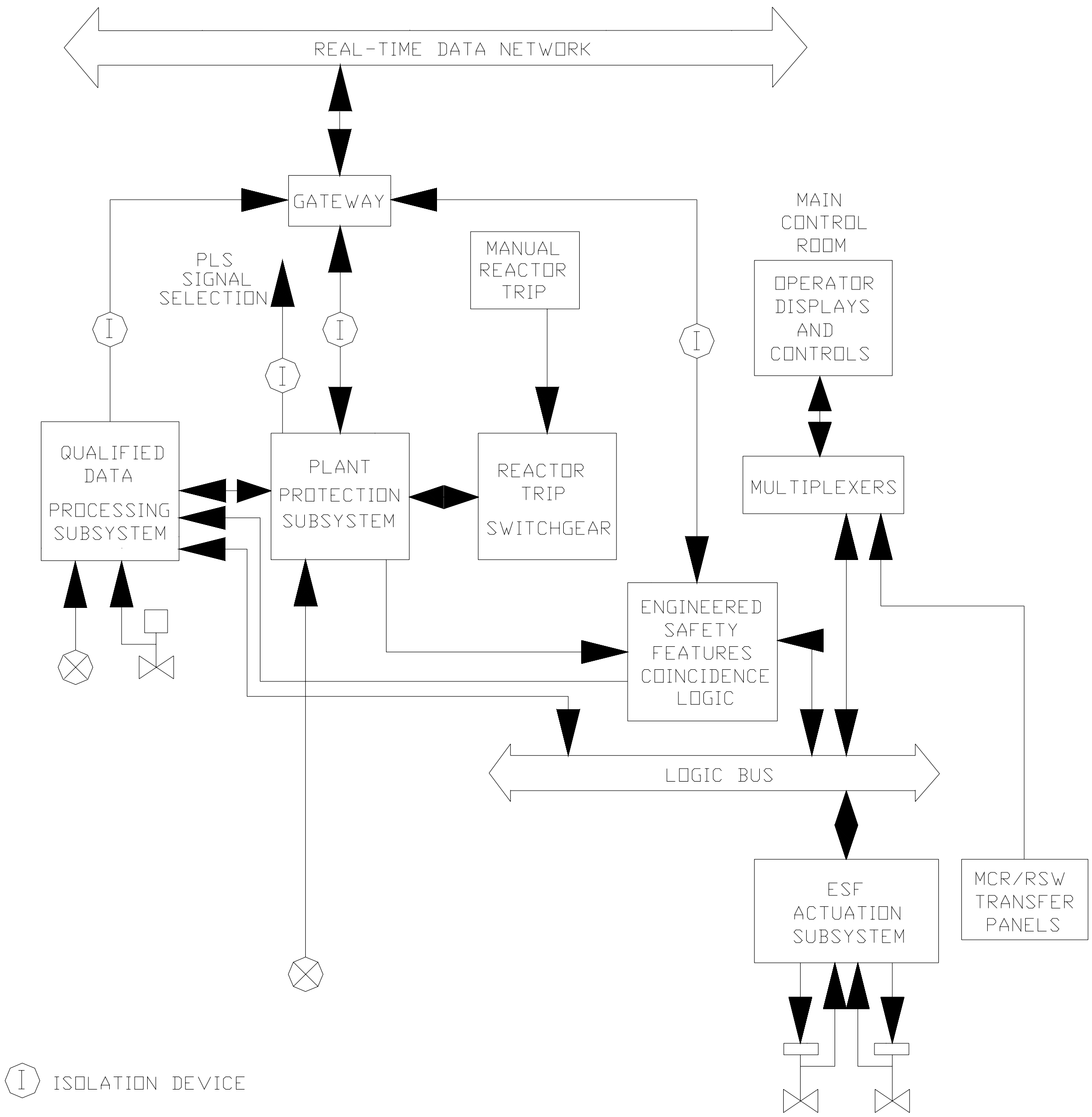


Figure 7.1-2

Protection and Safety Monitoring System

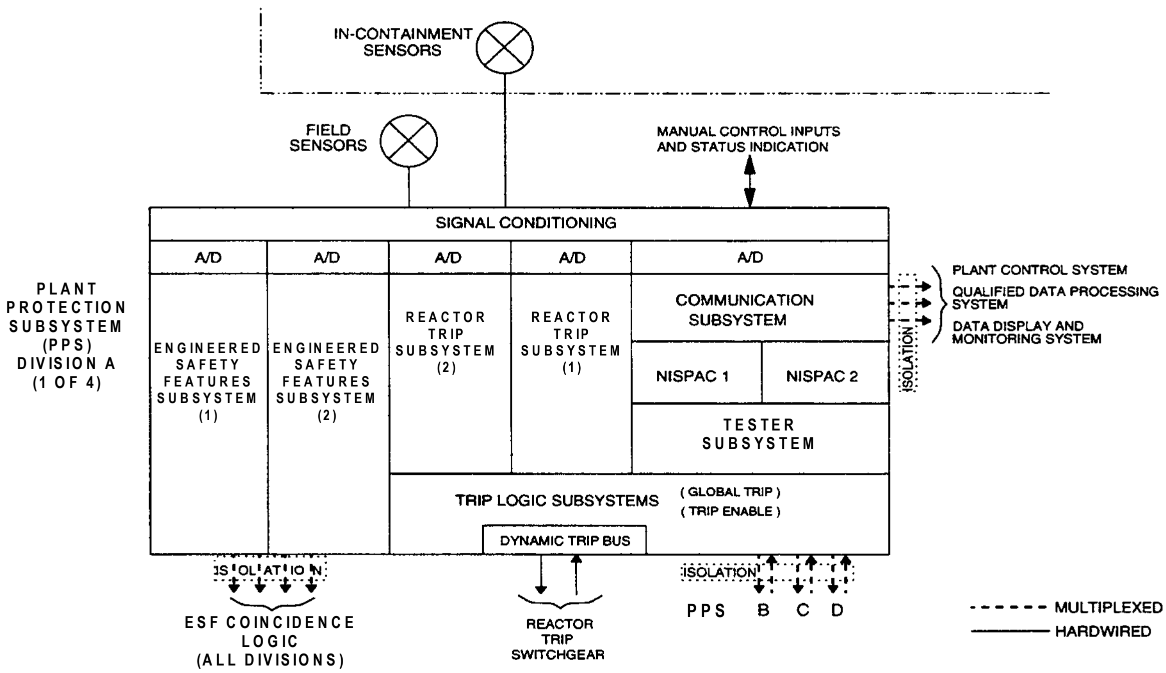


Figure 7.1-3A

Plant Protection Subsystem (Eagle Platform)

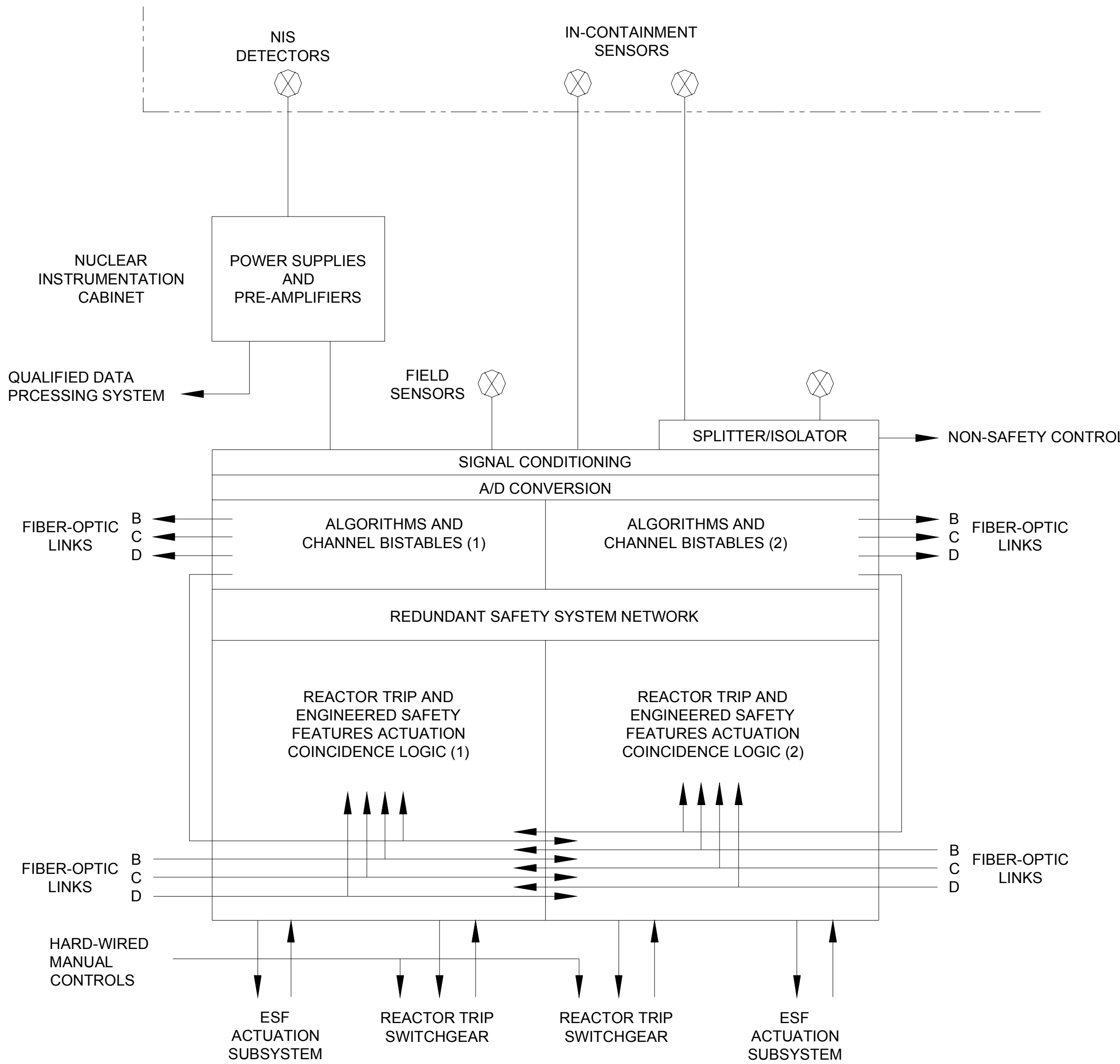


Figure 7.1-3B

Plant Protection Subsystem and Engineered Safety Features Coincidence Logic (Common Q Platform)

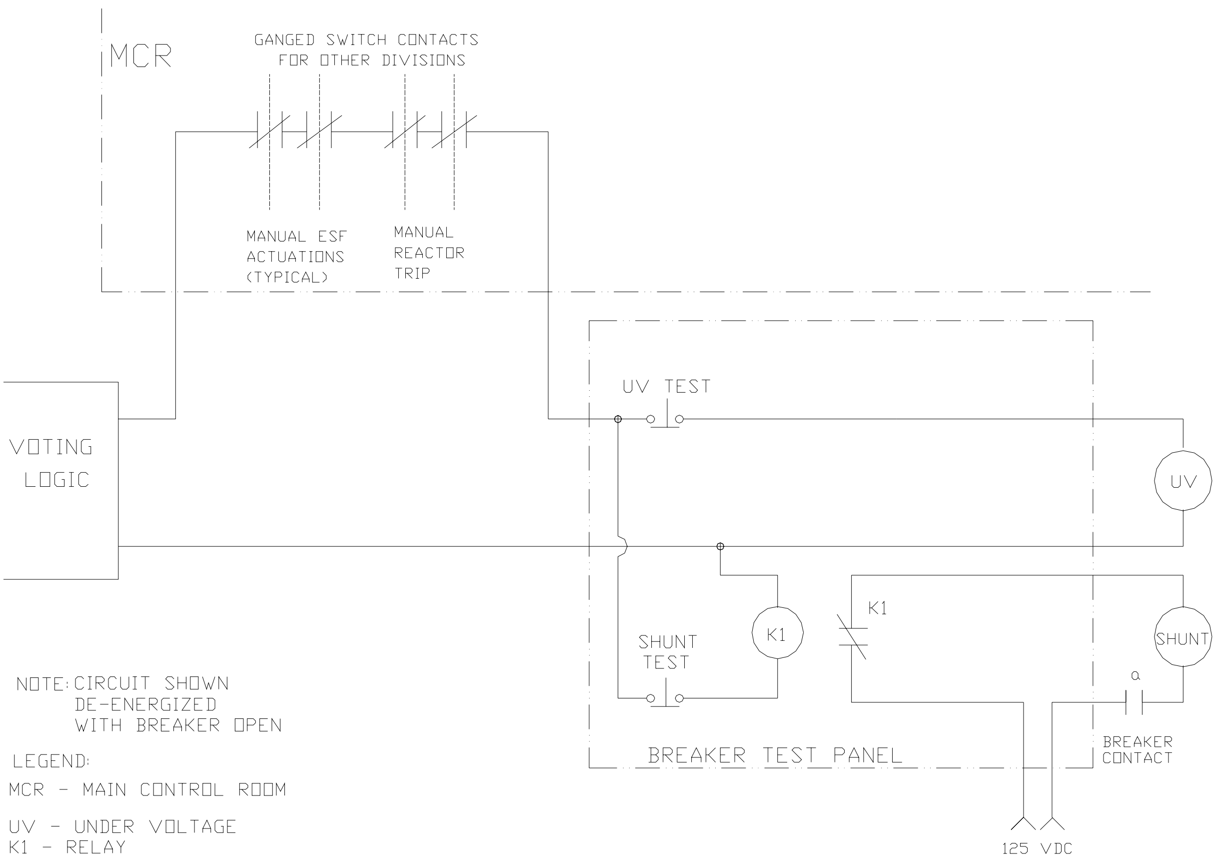


Figure 7.1-4

Reactor Trip Switchgear and Manual Trip Interface

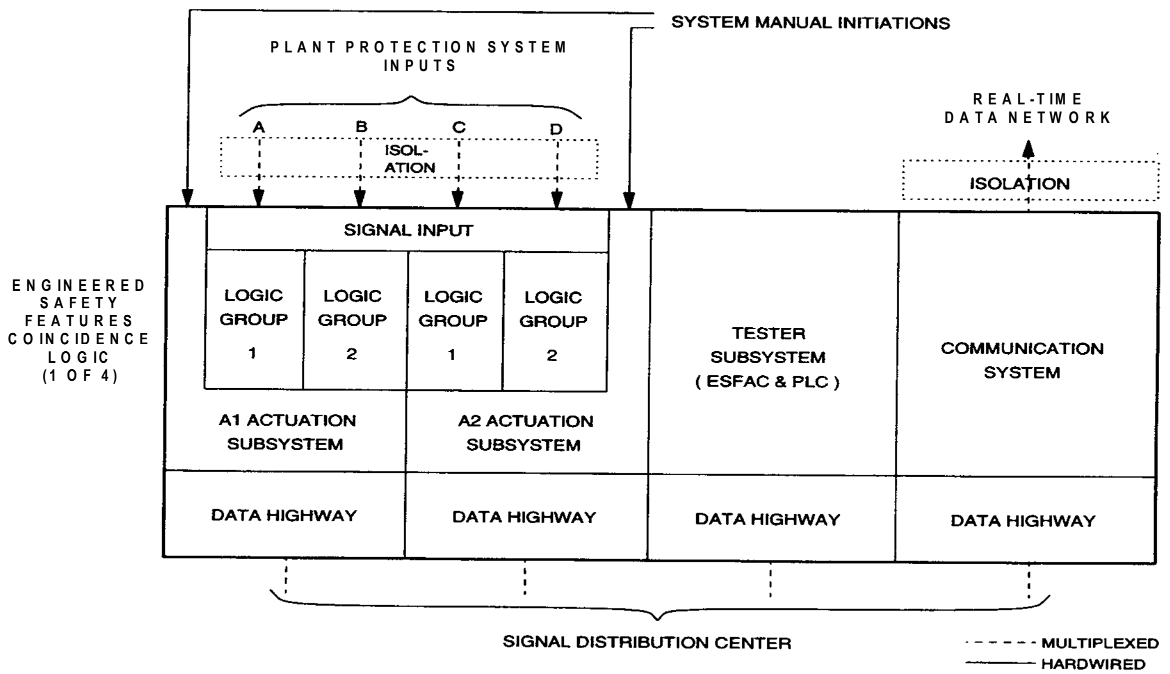


Figure 7.1-5

Engineered Safety Features Coincidence Logic (Eagle Platform)

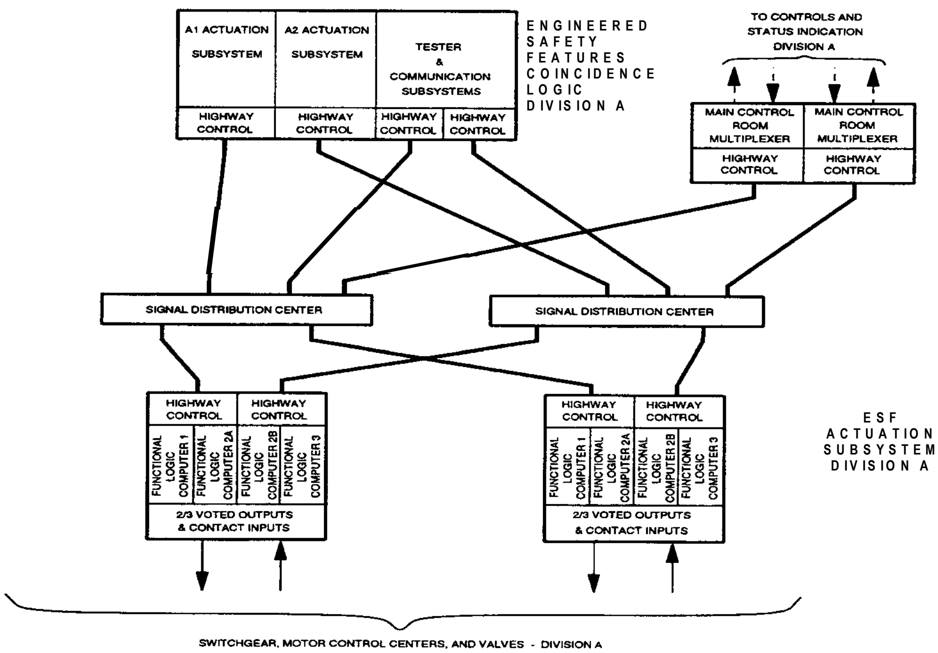


Figure 7.1-6

Protection Logic Communication Diagram (Eagle Platform)

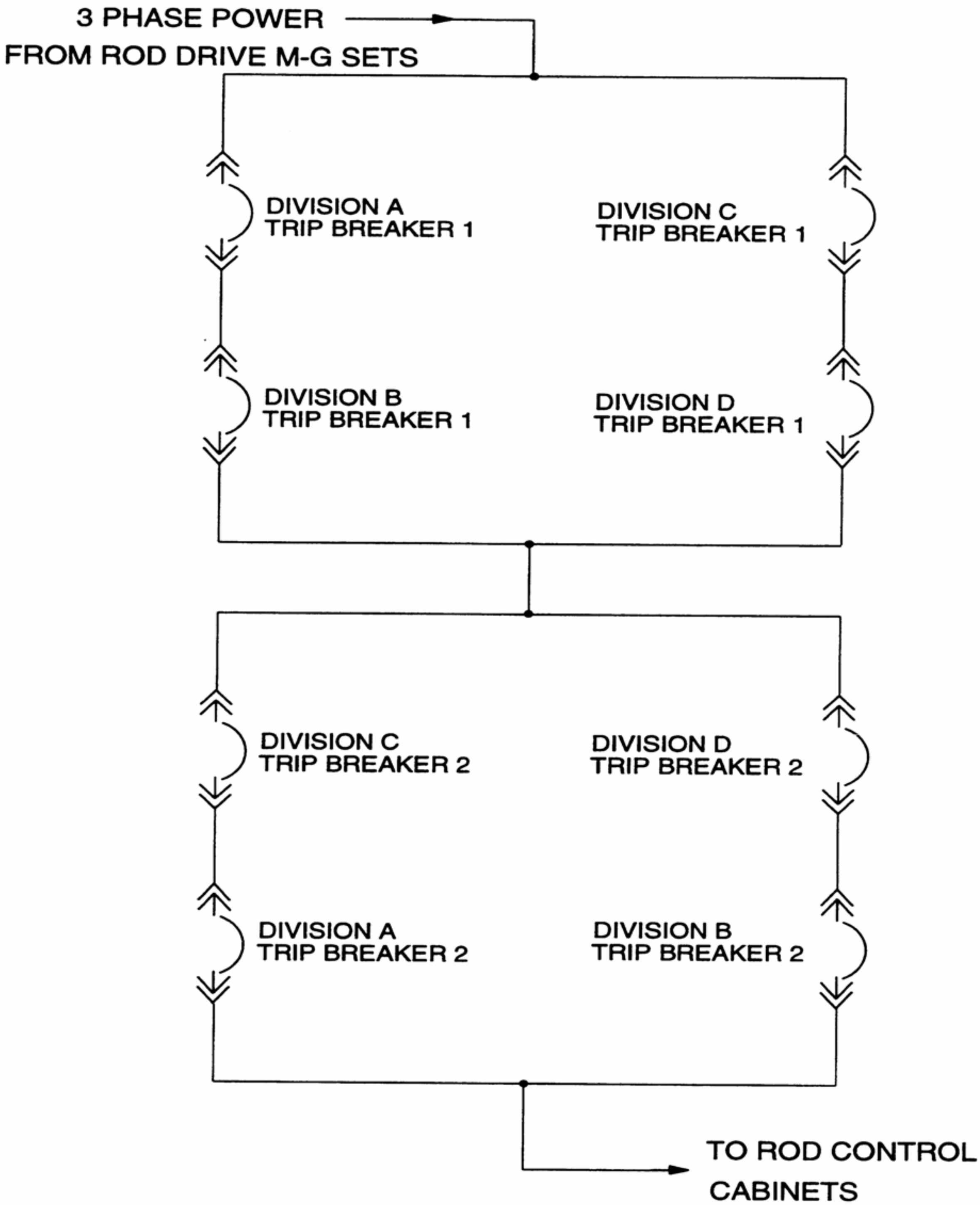


Figure 7.1-7

Reactor Trip Switchgear Configuration

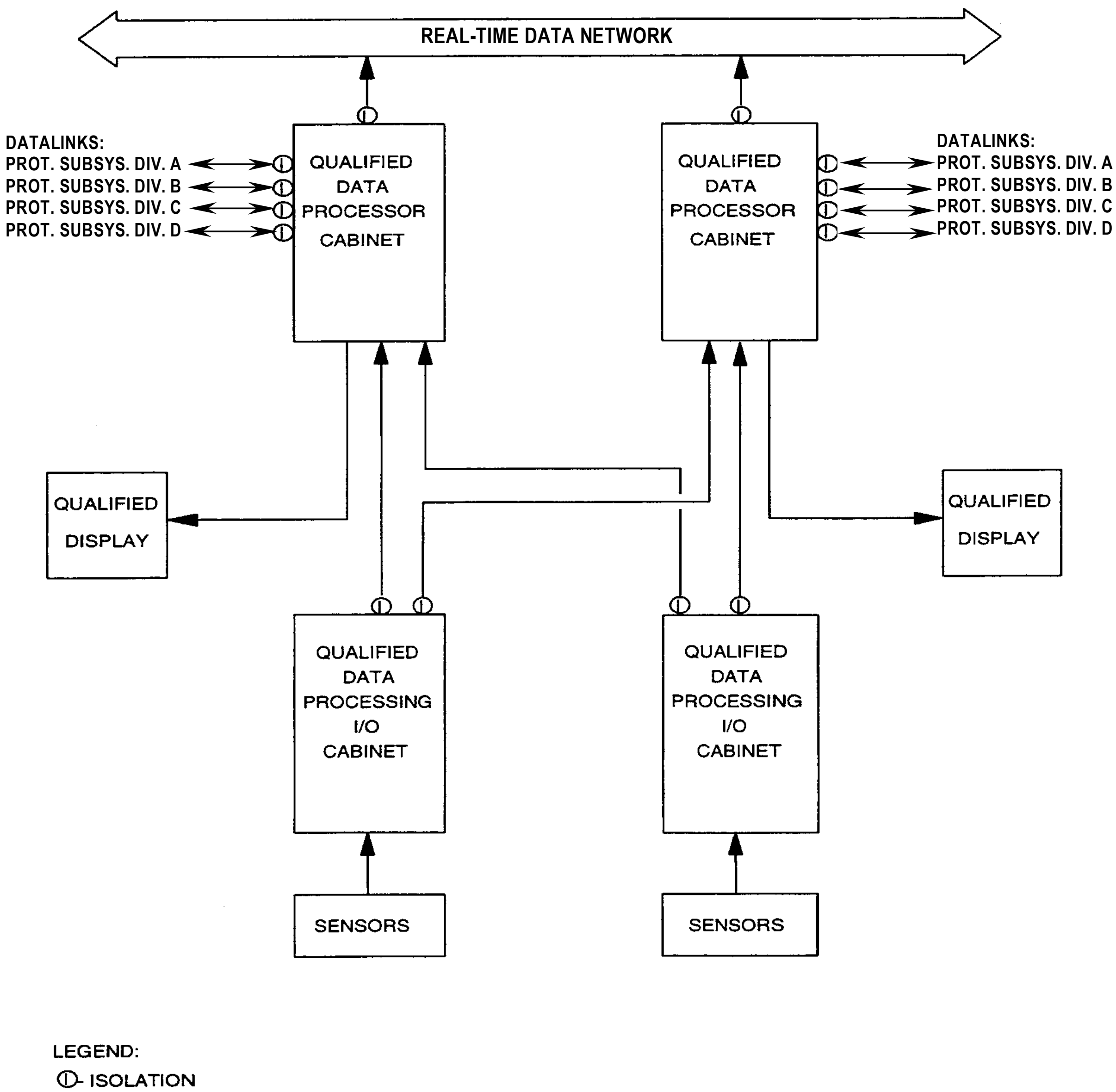


Figure 7.1-8A

Qualified Data Processing Subsystem (Eagle Platform – Channels B&C Only)

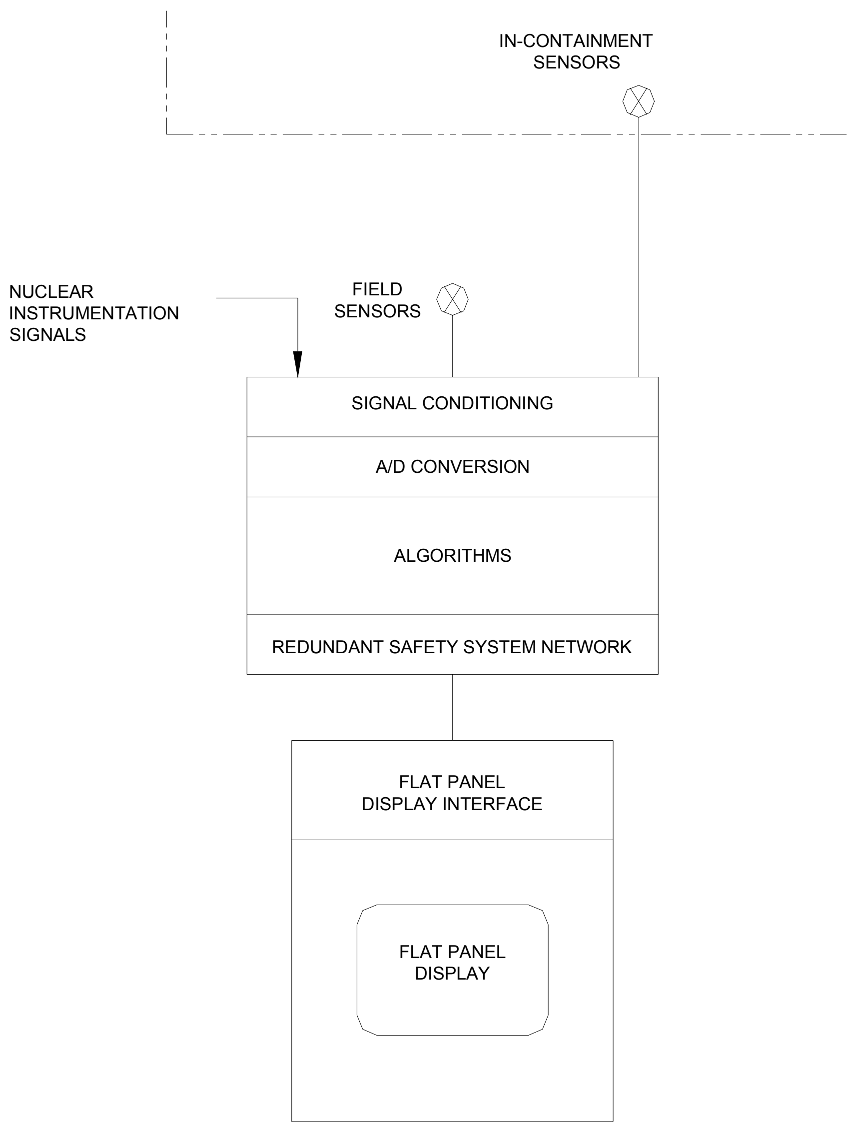


Figure 7.1-8B

Qualified Data Processing Subsystem (Common Q Platform – Channels B&C Only)

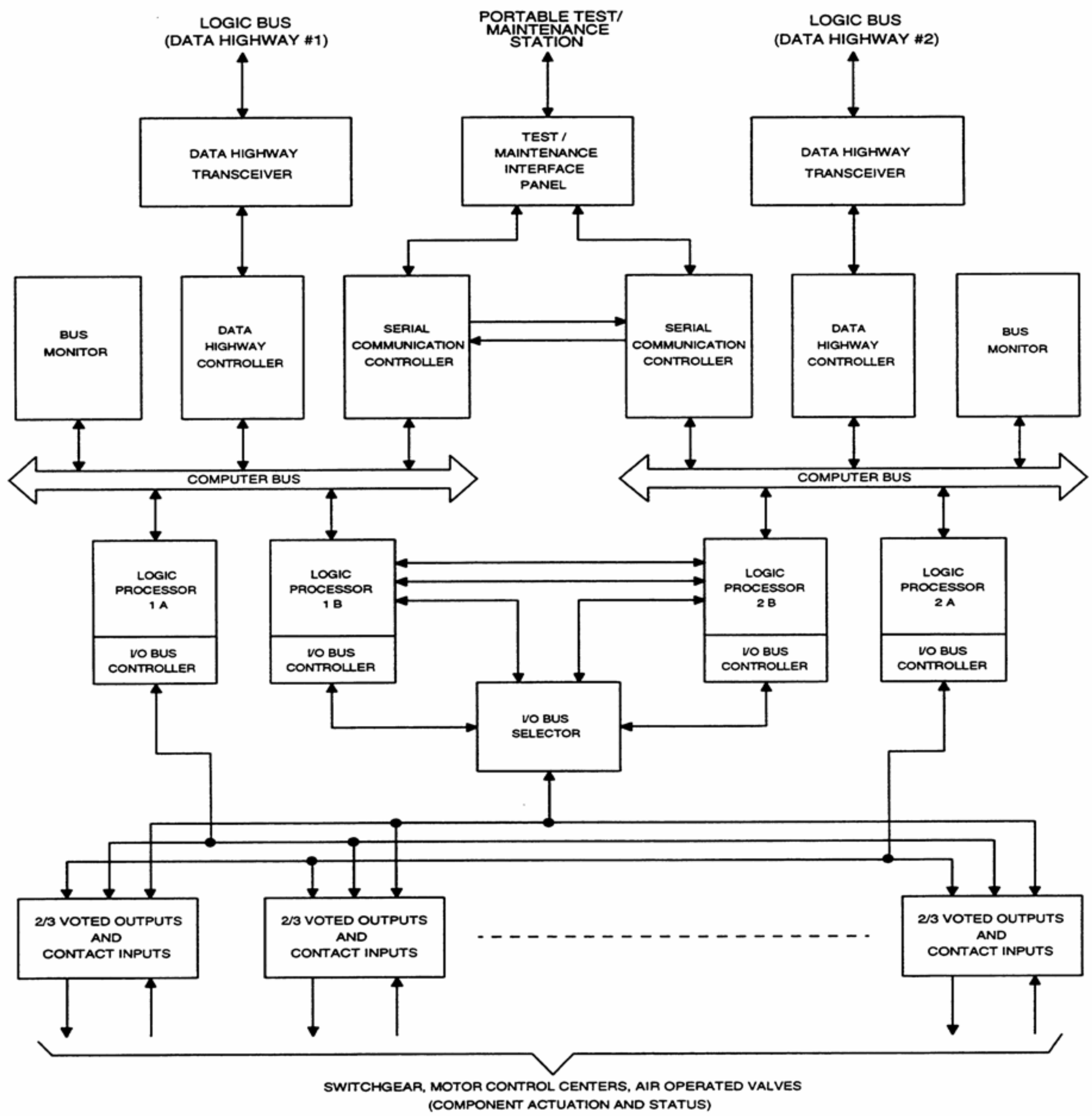


Figure 7.1-9A

Engineered Safety Features Actuation Subsystem
(Eagle Platform)

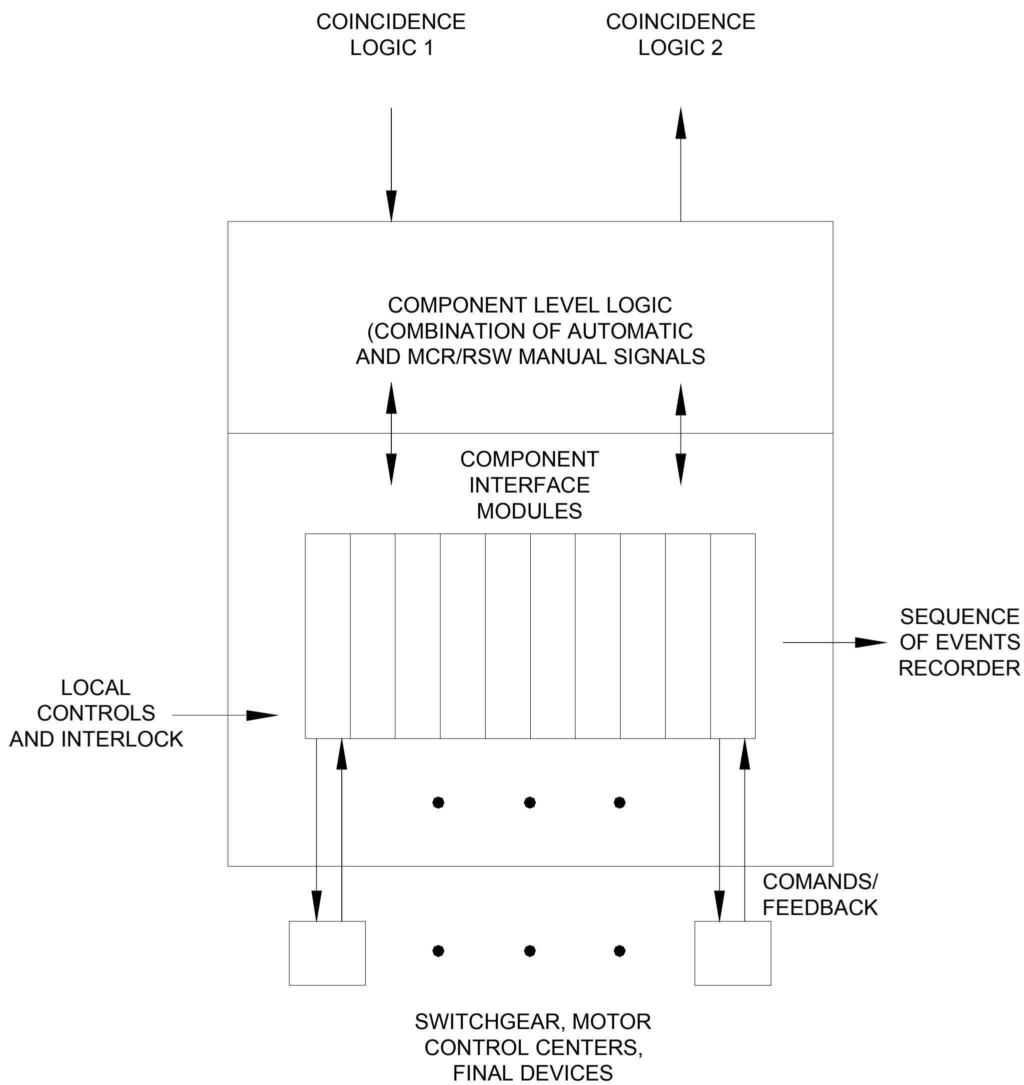


Figure 7.1-9B

Engineered Safety Features Actuation Subsystem (Common Q Platform)

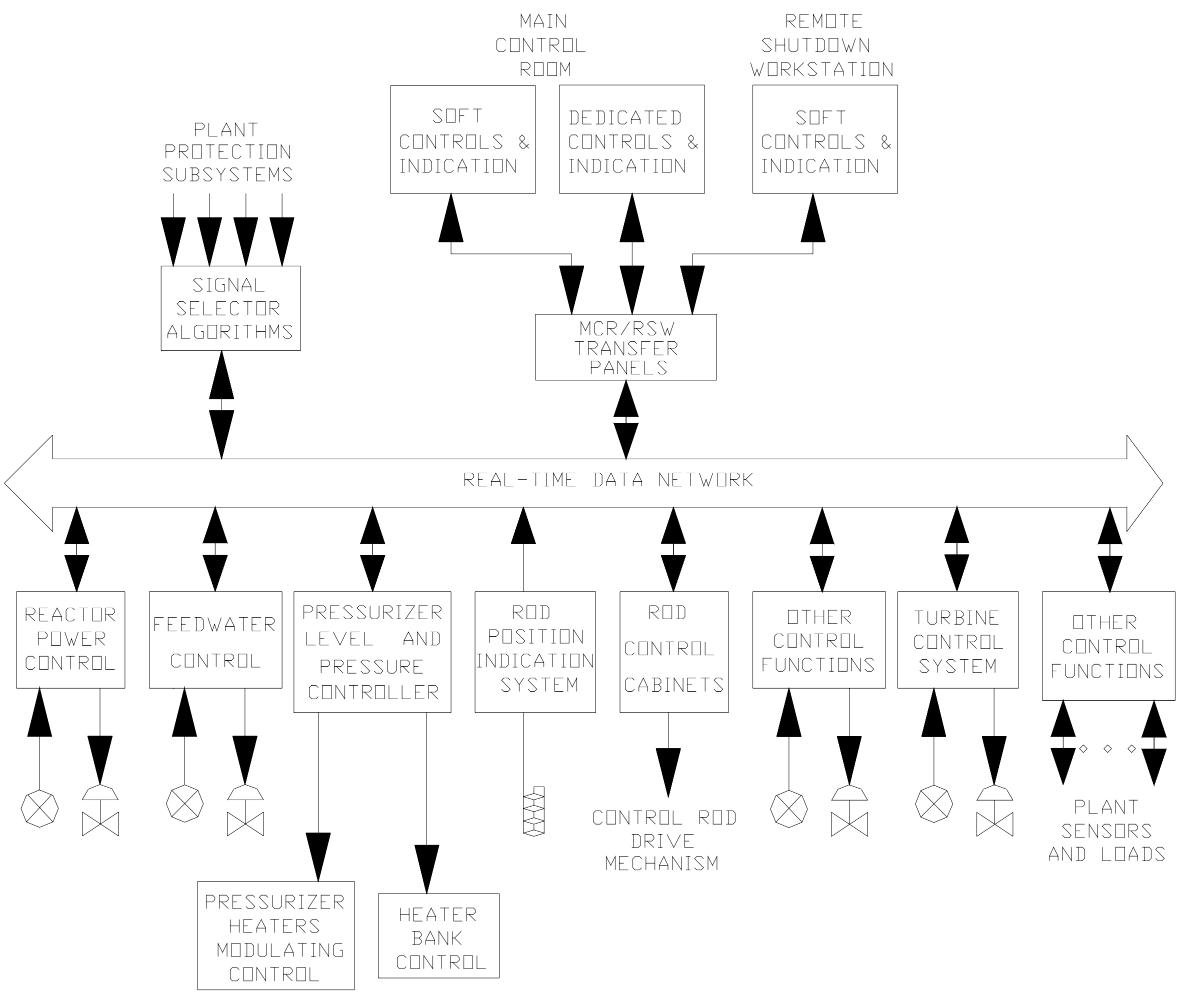


Figure 7.1-10

Plant Control System

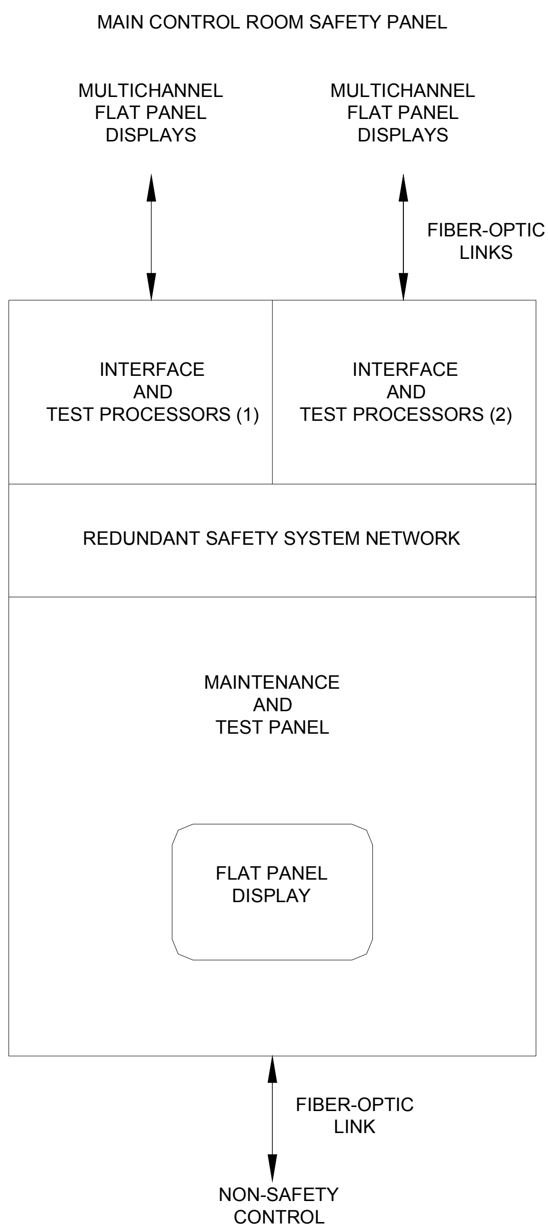


Figure 7.1-11

Maintenance and Test Subsystem (Common Q Platform)

7.2 Reactor Trip

7.2.1 Description

Considerations, such as mechanical or hydraulic limitations on equipment or heat transfer requirements on the reactor core, define a safe operating region for the plant. Maneuvering of the plant within this safe operating region is permitted in response to normal power generation demands. The plant design provides margin to the safety limits so that an unsafe condition is not caused by the transients induced by normal operating changes. The plant control system attempts to keep the reactor operating away from any safety limit. Excursions toward a limit occur because of abnormal demands, malfunctions in the control system, or by severe transients induced by occurrence of a Condition II or III event, as discussed in Chapter 15. Hypothetical events (Condition IV) are analyzed with respect to plant safety limits. The safety system keeps the reactor within the safe region by shutting down the reactor whenever safety limits are approached. Reactor trip is a protective function performed by the protection and safety monitoring system when it anticipates an approach of a parameter to its safety limit. Reactor shutdown occurs when electrical power is removed from the rod drive mechanism coils, allowing the rods to fall by gravity into the reactor core.

The equipment involved in reactor trip is shown in simplified block diagram form in Figure 7.1-2. Section 7.1 provides a description of the equipment. The equipment involved is:

- Sensors and manual inputs
- Protection and safety monitoring system cabinets
- Reactor trip switchgear

The plant protection subsystems maintain surveillance of key process variables directly related to equipment mechanical limitations (such as pressure), and of variables which directly affect the heat transfer capability of the reactor (such as flow and temperature). Some limits, such as the overtemperature ΔT setpoint, are calculated in the protection and safety monitoring system from other parameters when direct measurement of the variable is not possible. Table 7.2-1 lists variables monitored for reactor trip.

Four redundant measurements, using four separate sensors, are made for each variable used for reactor trip. Analog signals are converted to digital form by analog-to-digital converters within the protection and safety monitoring system. Signal conditioning is applied to selected inputs following the conversion to digital form. Following necessary calculations and processing, the measurements are compared against the applicable setpoint for that variable. A partial trip signal for a parameter is generated if one channel's measurement exceeds its predetermined or calculated limit. Processing of variables for reactor trip is identical in each of the four redundant divisions of the protection system. Each division sends its partial trip status to each of the other three divisions over isolated multiplexed data links. Each division is capable of generating a reactor trip signal if two or more of the redundant channels of a single variable are in the partial trip state.

The reactor trip signal from each of the four divisions of the protection and safety monitoring system is sent to the corresponding reactor trip switchgear breakers.

Each of the four reactor trip actuation divisions consists of two reactor trip circuit breakers. The reactor is tripped when two or more actuation divisions output a reactor trip signal. This automatic trip demand initiates the following two actions. It deenergizes the under-voltage trip attachments on the reactor trip breakers, and it energizes the shunt trip devices on the reactor trip breakers. Either action causes the breakers to trip. Opening the appropriate trip breakers removes power to the rod drive mechanism coils, allowing the rods to fall into the core. This rapid negative reactivity insertion causes the reactor to shutdown.

Bypasses of parameter channels used to generate reactor trip signals and of reactor trip actuation divisions are permitted as described in subsection 7.2.1.1.12. Single failure criterion is met even when one channel or division is bypassed. Bypassing two or more redundant channels or divisions is not allowed.

Subsection 7.2.1.1 provides a description of each of the reactor trip functions. Figure 7.2-1 shows the functional diagrams for reactor trips, as well as functional diagrams for other related plant functions.

7.2.1.1 Functional Description

The following subsections describe the specific reactor trip functions and are grouped according to the following nine conditions:

- Subsection 7.2.1.1.1 Nuclear Startup Trips
- Subsection 7.2.1.1.2 Nuclear Overpower Trips
- Subsection 7.2.1.1.3 Core Heat Removal Trips
- Subsection 7.2.1.1.4 Primary Overpressure Trips
- Subsection 7.2.1.1.5 Loss of Heat Sink Trips
- Subsection 7.2.1.1.6 Feedwater Isolation Trip
- Subsection 7.2.1.1.7 Automatic Depressurization Systems Actuation Reactor Trip
- Subsection 7.2.1.1.8 Core Makeup Tank Injection Trip
- Subsection 7.2.1.1.9 Reactor Trip on Safeguards Actuation
- Subsection 7.2.1.1.10 Manual Reactor Trip

Table 7.2-2 lists the reactor trips and summarizes the coincidence logic to trip. Table 7.2-3 provides the interlocks for each trip. Table 7.2-4, lists system level manual inputs to reactor trip functions.

7.2.1.1.1 Nuclear Startup Trips

Source Range High Neutron Flux Trip

Source range high neutron flux trips the reactor when two of the four source range channels exceed the trip setpoint. This trip provides protection during reactor startup and plant shutdown. It may be manually blocked and the high voltage source range detector power supply de-energized when the intermediate range neutron flux is above the P-6 setpoint value. It is automatically blocked by the power range neutron flux interlock (P-10). The trip may be manually reset when neutron flux is between P-6 and P-10. The reset occurs automatically when the intermediate range

flux decreases below P-6. The channels can be individually bypassed to permit channel testing during plant shutdown or prior to startup. This bypass action is indicated in the main control room.

Figure 7.2-1, sheet 3 shows the logic for this trip. This sheet also shows the development of permissive P-6 while P-10 is shown in Figure 7.2-1, sheet 4.

Intermediate Range High Neutron Flux Trip

Intermediate range high neutron flux trips the reactor when two of the four intermediate range channels exceed the trip setpoint. This trip, which provides protection during reactor startup, can be manually blocked if the power range channels are above approximately 10-percent power (P-10). The trip is automatically reset when the power range channels indicate less than 10-percent power. The intermediate range channels, including detectors, are separate from the power range channels. The intermediate range channels can be individually bypassed to permit channel testing during plant shutdown or prior to startup. This bypass action is indicated in the main control room.

Figure 7.2-1, sheet 3 shows the logic for this trip. The development of permissive P-10 is shown in Figure 7.2-1, sheet 4.

Power Range High Neutron Flux Trip (Low Setpoint)

Power range high neutron flux (low setpoint) trips the reactor when two of the four power range channels exceed the trip setpoint.

The trip, which provides protection during startup, can be manually blocked when the power range channels are above approximately 10-percent power (P-10). The trip is automatically reset when the power range channels indicate less than 10-percent power.

Figure 7.2-1, sheet 3 shows the logic for this trip. The development of permissive P-10 is shown on Figure 7.2-1, sheet 4.

7.2.1.1.2 Nuclear Overpower Trips

Power Range High Neutron Flux Trip (High Setpoint)

Power range high neutron flux (high setpoint) trips the plant when two of the four power range channels exceed the trip setpoint. It provides protection against excessive core power generation during normal operation and is always active. Figure 7.2-1, sheet 4 shows the logic for this trip.

Power Range High Positive Flux Rate Reactor Trip

This trip protects the reactor when a sudden abnormal increase in power occurs in two out of the four power range channels. It provides protection against ejection accidents of low worth rods from midpower. It is always active. A channel is tripped when rate-sensitive circuits in the channel detect rates of change in nuclear power above the setpoint value. The channel trip is latched such that the partial trip signal does not disappear when the rate of change in power goes below the

setpoint value. Once latched, the channel can only be reset from the main control room by manual action. The reactor is tripped when two out of the four rate channels have tripped.

Figure 7.2-1, sheet 4 shows the logic for this trip.

7.2.1.1.3 Core Heat Removal Trips

Overtemperature ΔT Reactor Trip

The overtemperature ΔT trip provides core protection to prevent departure from nucleate boiling for combinations of pressure, power, coolant temperature, and axial power distribution. The protection is provided if the transient is slow with respect to piping transient delays from the core to the temperature detectors and pressure is within the range between the high and low pressure reactor trips. This setpoint includes corrections for changes in density and heat capacity of water with temperature and dynamic compensation for piping delays from the core to the loop temperature detectors. With normal axial power distribution, this reactor trip limit is always below the core safety limit. If axial peaks are greater than design, as indicated by the difference between upper and lower power range nuclear detectors, the reactor trip is automatically reduced according to the following calculation. Two hot leg temperature measurements per loop are combined with individual cold leg temperature measurements to form four ΔT and T_{avg} signals.

The ΔT setpoint for this trip is continuously calculated, with one set of temperature measurements per loop.

If $\frac{\Delta T\,(1+\tau_4 s)}{(1+\tau_5 s)} \geq \Delta T$ setpoint, a reactor trip is initiated.

ΔT setpoint is calculated from the following equation:

$$\Delta T_{SETPOINT} = \Delta T_o \left[K_1 - K_2 \left(\frac{1+\tau_1 s}{1+\tau_2 s} \right) \left(T_{avg} - T^o_{avg} \right) + K_3 \left(P - P_0 \right) - f_1(\Delta\phi) \right]$$

Where:

ΔT	=	Measured ΔT by resistance temperature detector instrumentation
ΔT_o	=	Indicated ΔT at rated thermal power
T_{avg}	=	Average reactor coolant temperature (°F)
$T°_{avg}$	=	Nominal T_{avg} at rated thermal power
P	=	Pressurizer pressure (psig)
P_o	=	Nominal operating pressure
K_1	=	Preset bias

K_2 = Preset gain which compensates for effects of temperature on the departure from nucleate boiling limits

K_3 = Preset gain which compensates for effects of pressure on the departure from nucleate boiling limits

τ_1, τ_2 = Preset constants which compensate for piping and instrument time delay(s)

τ_4, τ_5 = Preset constants used in lead-lag compensator for ΔT

s = Laplace transform operator

$f_1(\Delta\varphi)$ = A function of the neutron flux difference between upper and lower ionization chamber flux signals

Two separate ionization chambers supply the upper and lower flux signal for each overtemperature ΔT channel.

Increases in Δφ beyond a predefined deadband results in a decrease in trip setpoint.

The required one pressurizer pressure parameter per loop is obtained from four separate sensors connected to pressure taps at the top of the pressurizer.

Figure 7.2-1, sheet 5, shows the logic for the overtemperature ΔT trip function.

Overpower ΔT Trip

The overpower ΔT reactor trip provides confidence of fuel integrity during overpower conditions, limits the required range for overtemperature ΔT protection, and provides a backup to the power range high neutron flux trip.

The ΔT setpoint for this trip is continuously calculated for each loop.

If $\Delta T \frac{(1+\tau_4 s)}{(1+\tau_5 s)} \geq \Delta T$ setpoint, a reactor trip is initiated.

ΔT setpoint is calculated from the following equation:

$$\Delta T_{SETPOINT} = \Delta T_o \left[K_4 - K_5 \left(\frac{\tau_3 s}{1+\tau_3 s} \right) T_{avg} - K_6 \left(T_{avg} - T'_{avg} \right) - f_2 (\Delta\phi) \right]$$

Where:

ΔT = Measured ΔT by resistance temperature detector instrumentation

ΔT_o = Indicated ΔT at rated thermal power

$f_2(\Delta\varphi)$ = A function of the neutron flux difference between upper and lower ionization chamber flux signals

K_4 = A preset bias

K_5 = A constant which is equal to zero for decreasing T_{avg}

K_6 = A constant which is equal to zero for T_{avg} less than T'_{avg}

T'_{avg} = Indicated T_{avg} at rated thermal power (°F)

T_{avg} = Average reactor coolant temperature (°F)

τ_4, τ_5 = Preset constants used in lead-lag compensator for ΔT

τ_3 = Preset time constant

s = Laplace transform operator

The source of temperature and neutron flux information is identical to that of the overtemperature ΔT trip, and the resultant ΔT setpoint is compared to the same measured ΔT. Figure 7.2-1, sheet 5, shows the logic for this trip function.

Reactor Trip on Low Pressurizer Pressure

This trip protects against low pressure, which could lead to departure from nucleate boiling. The parameter sensed is reactor coolant pressure as measured in the pressurizer. This trip is automatically blocked when reactor power is below the P-10 permissive setpoint to allow control rod testing during cold, depressurized conditions. The trip is automatically reset when reactor power is above the P-10 setpoint.

Figure 7.2-1, sheet 5, shows the logic for this trip. The development of the P-10 permissive is shown in Figure 7.2-1, sheet 4.

Reactor Trip on Low Reactor Coolant Flow

This trip protects against departure from nucleate boiling in the event of low reactor coolant flow. Flow in each hot leg is measured at the hot leg elbow. The trip on low flow in either hot leg is automatically blocked when reactor power is below the P-8 permissive setpoint, and the trip on low flow in both hot legs is automatically blocked when reactor power is below the P-10 permissive setpoint. This enhances reliability by preventing unnecessary reactor trips. The two trip functions are automatically reset when reactor power is above the P-8 and P-10 setpoints.

Figure 7.2-1, sheet 5 shows the logic for this trip. The development of permissives P-10 and P-8 are shown in Figure 7.2-1, sheet 4.

Reactor Trip on Reactor Coolant Pump Underspeed

This trip protects the reactor core from departure from nucleate boiling in the event of a loss of flow in more than one loop. This protection is provided by tripping the reactor when the speed on two out of the four reactor coolant pumps falls below the setpoint. Loss of flow in more than one loop could be caused by a voltage or frequency transient in the plant power supply such as would occur during a station blackout. It could be caused by inadvertent opening of more than one reactor coolant pump circuit breaker. There is one speed detector mounted on each reactor coolant pump. The trip is automatically blocked when reactor power is below the P-10 permissive setpoint to enhance reliability by preventing unnecessary reactor trips. The trip is automatically reset when reactor power is above the P-10 setpoint.

Figure 7.2-1, sheet 5, shows the logic for this trip. The development of P-10 is shown in Figure 7.2-1, sheet 4.

Reactor coolant pump speed is detected by a probe mounted on the reactor coolant pump frame. The speed signal is transmitted to the protection and safety monitoring system to provide the input to the trip logic function.

The reactor coolant pump underspeed trip provides a direct measurement of the parameter of interest. It permits the plant to ride through many postulated voltage dip transients without reactor trip if safety limits are not violated. Selection of the underspeed trip setpoint and time response provide for the timely initiation of reactor trip during the complete loss of flow accident and the limiting frequency decay event, consistent with the analysis results reported in Chapter 15.

The reactor coolant pump speed detectors perform their protective function (during the complete loss of flow accident and the limiting frequency decay event) in an environment (temperature, humidity, pressure, chemical, and radiation) that is not changed by the event. Therefore, it is not necessary to impose environmental qualification requirements on these detectors more restrictive than those imposed for use under rated conditions. The reactor coolant pump speed detectors are qualified for use under rated conditions with their performance verified by operation in the plant. The reactor coolant pump speed detectors are qualified to the most limiting vibrations experienced by pump operation.

Reactor Coolant Pump Bearing Water Temperature Trip

This trip is an anticipatory trip based on the expectation of a complete loss of reactor coolant flow if cooling water is lost to the reactor coolant pumps. This trip occurs before the reactor coolant pumps are tripped on the same measurement.

The reactor trip on high reactor coolant pump bearing water temperature in any single reactor coolant pump is automatically blocked when reactor power is below the P-8 permissive setpoint and the trip on high reactor coolant pump bearing water temperature in multiple pumps is automatically blocked when reactor power is below the P-10 permissive setpoint. This enhances reliability by preventing unnecessary reactor trips. The two parts of the trip are automatically reset when reactor power is above the P-8 and P-10 setpoints.

Figure 7.2-1, sheet 5, shows the logic for this trip.

7.2.1.1.4 Primary Overpressure Trips

Pressurizer High Pressure Reactor Trip

This trip protects the reactor coolant system against system overpressure. The same sensors used for the pressurizer low pressure reactor trip are used for the high pressure trip except that separate setpoints are used. The high pressurizer pressure protection trips the reactor when two out of the four pressurizer pressure channels exceed the trip setpoint. There are no interlocks or permissives associated with this trip function.

Figure 7.2-1, sheet 6, shows the logic for this trip.

Pressurizer High Water Level Reactor Trip

This trip is provided as backup to the high pressurizer pressure reactor trip and serves to prevent water relief through the pressurizer safety valves. The high pressurizer water level protection trips the reactor when two out of the four pressurizer water level channels exceed the trip setpoint. The level signal is compensated for both reference leg temperature and system pressure. The trip is automatically blocked when reactor power is below the P-10 permissive setpoint. This permits control rod testing with the plant cold and the pressurizer water solid. The trip is automatically reset when reactor power is above the P-10 setpoint.

Figure 7.2-1, sheet 6, shows the logic for the trip. The development of P-10 is shown in Figure 7.2-1, sheet 4.

7.2.1.1.5 Loss of Heat Sink Trip

Reactor Trip on Low Water Level in any Steam Generator

This trip protects the reactor from loss of heat sink in the event of a loss of feedwater to the steam generators. The reactor is tripped when two out of the four water level sensors in any steam generator produce signals below the setpoint value.

Figure 7.2-1, sheet 7, shows the logic for the trip. There are no interlocks or permissives associated with this trip.

7.2.1.1.6 Feedwater Isolation Trip

High-2 Steam Generator Water Level in Any Steam Generator

This function is an anticipatory trip based on the expectation that a reactor trip would occur after steam generator feedwater is isolated. The plant control system uses a lower steam generator water level setpoint, High-1, to close the feedwater control valves. This provides an interval for operator action to prevent total isolation of the steam generator and a reactor trip before the High-2 setpoint is exceeded. The trip on High-2 steam generator water level may be manually blocked below the P-11 permissive setpoint to allow control rod testing. The trip is automatically reset when the pressurizer pressure is above the P-11 setpoint.

Figure 7.2-1, sheet 10, shows the logic for this trip function.

7.2.1.1.7 Automatic Depressurization Systems Actuation Reactor Trip

A reactor trip is initiated if an automatic depressurization system actuation occurs either automatically or manually. This provides a reactor trip if the system is depressurized and a trip is not initiated from another source. The automatic depressurization system actuation function is discussed in subsection 7.3.1.2.4.

Manual automatic depressurization system actuation is initiated from either of two sets of controls in the main control room. Operating either of the two sets of controls also sends a reactor trip signal to the reactor trip switchgear breakers. Outputs on the control sets, physically and electrically separated, send their position status to the protection and safety monitoring system. These inputs de-energize the undervoltage trip attachments on the reactor trip breakers, causing them to trip open. Additional outputs interrupt power to the shunt trip interposing relays, actuating the shunt trip attachments on each reactor trip circuit breaker. These provide a backup to the undervoltage trip of the breakers.

Figure 7.2-1, sheet 15 shows the logic for this trip function. There are no interlocks or bypasses associated with this trip.

7.2.1.1.8 Core Makeup Tank Injection Trip

A reactor trip is initiated if core makeup injection occurs either automatically or manually. Since core makeup tank injection results in a trip of the reactor coolant pumps, providing a reactor trip upon core makeup tank injection maximizes the margin to DNB at all power levels. The core makeup tank injection function is discussed in subsection 7.3.1.2.3.

Manual core makeup tank injection is initiated from either of two controls in the main control room. Operating either of the two controls also sends a reactor trip signal to the reactor trip switchgear breakers. Outputs on each control, physically and electrically separated, send their position status to the protection and safety monitoring system. These inputs de-energize the undervoltage trip attachments on the reactor trip breakers, causing them to trip open. Additional outputs on each control interrupt power to the shunt trip interposing relays, actuating the shunt trip attachments on each reactor trip circuit breaker. These provide a backup to the undervoltage trip of the breakers.

Figure 7.2-1, sheets 2 and 12 show the logic for this trip function. There are no interlocks or bypasses associated with this trip.

7.2.1.1.9 Reactor Trip on Safeguards Actuation

A reactor trip is initiated with any signal that causes a safeguards actuation. This reactor trip occurs whether the safeguards actuation is commanded automatically or manually. The means for actuating safeguards automatically are described in Section 7.3. This trip protects the core against a loss of reactor coolant or a steam line rupture.

Manual safeguards actuation is initiated from either of two controls in the main control room. Operating either of the two controls also sends a reactor trip signal to the reactor trip switchgear breakers. Outputs on each control, physically and electrically separated, send their position status to the protection and safety monitoring system. These inputs de-energize the undervoltage trip attachments on the reactor trip breakers, causing them to trip open. Additional outputs on each control interrupt power to the shunt trip interposing relays, actuating the shunt trip attachments on each reactor trip circuit breaker. These provide a backup to the undervoltage trip of the breakers.

Figure 7.2-1, sheets 2 and 11, show the logic for this trip function. There are no interlocks or bypasses associated with this trip.

7.2.1.1.10 Manual Reactor Trip

The manual reactor trip consists of 2 controls in the main control room, either of which trip all 8 of the reactor trip switchgear breakers. The reactor trip circuit breakers contain both undervoltage and shunt trip attachments. The shunt trip acts as a diverse backup to the undervoltage trip in the breakers. Contacts on each control, physically and electrically separated, are in series with the undervoltage trip attachment on the reactor trip breakers, the shunt trip attachment interposing relays, and the power outputs at the protection and safety monitoring system cabinet. Actuating either control interrupts power from the voting logic to the undervoltage trip attachments, releasing them. It also interrupts power to shunt trip interposing relays, actuating the shunt trip attachments. The breakers trip when either the shunt trip attachments are energized or the undervoltage trip attachments are de-energized. Actuating either manual trip control causes each breaker to trip by initiating both of these actions.

Figure 7.2-1, sheets 2 and 13, show the logic for the manual trip. There are no interlocks or bypasses associated with this trip.

7.2.1.1.11 Reactor Trip System Interlocks

The interlocks used in the reactor trip functions are designated as P-xx permissives. Table 7.2-3 provides a listing of these interlocks. These permissives are implemented at the channel level rather than at the logic level because plant availability has been determined to be improved using this technique of integrating permissives into each channel.

Manual blocks to reactor trip are listed on Table 7.2-4 and are described in the following subsections. The source, intermediate, low power, and steam generator water level manual blocks, when used in conjunction with the applicable permissives, are implemented during startup.

Source Range Block (One Control for each Division)

The source range reactor trip may be manually blocked upon the occurrence of the P-6 permissive and is automatically reset when the permissive condition is not met. The channel is automatically blocked upon the occurrence of the P-10 permissive with the block automatically removed when the P-10 condition is not met. Figure 7.2-1, sheet 3, shows these blocks.

Intermediate Range Block (One Control for each Division)

The intermediate range reactor trip may be manually blocked upon the occurrence of the P-10 permissive and is automatically reset when the permissive condition is not met. Figure 7.2-1, sheet 3, shows this block.

Power Range (Low Setpoint) Block (One Control for each Division)

The power range low setpoint reactor trip may be manually blocked upon the occurrence of the P-10 permissive and is automatically reset when the permissive condition is not met. Figure 7.2-1, sheet 3, shows this block.

Steam Generator High-2 Water Level Block (One Control for each Division)

The steam generator High-2 reactor trip may be manually blocked upon the occurrence of the P-11 permissive. This trip function is automatically reset when the permissive condition is not met. Figure 7.2-1, sheets 9, 10, and 11, illustrates the functional logic relating to this function.

Automatic Rod Withdrawal Block

An automatic rod withdrawal block occurs on a power range negative flux rate below the P-17 setpoint to block the remaining rods that are not inserted by the rapid power reduction system. Figure 7.2-1, sheet 4, shows this block function. This interlock is generated by the protection and safety monitoring system and forwarded to the plant control system for implementation.

7.2.1.1.12 Bypasses of Reactor Trip Functions

Each channel used in reactor trip can be bypassed, as discussed in subsection 7.1.2.9, except for reactor trips resulting from manual initiations. One channel can be bypassed for an indefinite period of time with the normal two-out-of-four trip logic automatically reverting to a two-out-of-three trip logic. Bypassing two or more channels is not allowed.

7.2.1.2 Design Basis for Reactor Trips

This section provides the design bases information on the reactor trip function, including the information required by Section 4 of IEEE-603-1991. Reactor trip is a protective function generated as part of the protection and safety monitoring system. Those design bases relating to the equipment that initiates and accomplishes reactor trips are contained in WCAP-15776 (Reference 2). The design bases presented here concern the variables monitored for reactor trips, the minimum performance requirements in generating the trips, and the requirements placed on reactor trips during various reactor operating modes.

7.2.1.2.1 Design Basis: Generating Station Conditions Requiring Reactor Trip (Paragraph 4.1 of IEEE-603-1991)

The generating station conditions requiring protective actions are analyzed in Chapter 15. Conditions that result in a reactor trip are listed in Table 15.0-6. This table correlates the accident conditions (II, III, or IV events) to each reactor trip.

7.2.1.2.2 Design Basis: Variables, Levels, Ranges, and Accuracies Used in Reactor Trip Functions (Paragraphs 4.1, 4.2, and 4.4 of IEEE-603-1991)

The variables monitored for reactor trips are:

- Neutron flux
- Reactor coolant pump bearing water temperature
- Pressurizer pressure
- Water level in the pressurizer
- Reactor coolant flow in each loop
- Speed of each reactor coolant pump
- Water level in each steam generator
- Reactor coolant inlet temperature (T_{cold}) in each loop
- Reactor coolant outlet temperature (T_{hot}) in each loop
- Position of each manual reactor trip switch

The ranges, accuracies, and response times for each variable are listed on Table 7.2-1.

A discussion on levels that require reactor trip is contained in subsection 7.2.1.1.

The allowable values for the limiting safety-related system settings and the trip setpoint for reactor trips are in the technical specifications (Chapter 16).

7.2.1.2.3 Design Basis: Spatially Dependent Parameters Used in Reactor Trip (Paragraph 4.6 of IEEE-603-1991)

The hot and cold leg temperature signals required for input to the protection and control functions are obtained using thermowell-mounted RTDs installed in each reactor coolant loop. The hot leg temperature measurement in each loop is accomplished using three fast-response, dual-element, narrow-range RTDs. The three thermowells in each hot leg are mounted approximately 120 degrees apart in the cross-sectional plane of the piping, to obtain a representative temperature sample. The temperatures measured by the three RTDs are different due to hot leg temperature streaming and vary as a function of thermal power. Therefore, these signals are averaged using electronic weighting to generate a hot leg average temperature. Provisions are incorporated into the process electronics to allow for operation with only two RTDs in service. The two RTD measurements can be biased to compensate for the loss of the third RTD.

Radially varying cold leg temperature is not a concern since the resistance temperature detectors are located downstream of the reactor coolant pumps. The pumps provide mixing of the coolant so that radial temperature variations do not exist.

Radial neutron flux is not a spatially dependent concern because of core radial symmetry. Axial variation in neutron flux is used for calculations involving overtemperature and overpower ΔT. Excore detectors furnish this axially-dependent information to the overtemperature and overpower calculators. See subsection 7.2.1.1.3.

7.2.1.2.4 Design Basis: Operational Limits for Variables in Various Reactor Operating Modes (Paragraph 4.3 of IEEE-603-1991)

During startup or shutdown, reactor trips are provided for three ranges of neutron flux (source, intermediate, and power range). The source range, intermediate range, and power range (low setpoint) trips are manually blocked when the appropriate power escalation permissives are present. The trips are automatically reset during power de-escalation. Subsection 7.2.1.1.1 describes these reactor trips. Their interlocks are described in subsection 7.2.1.1.11.

During testing or maintenance, functions are provided to bypass a channel monitoring a variable for reactor trip. Although no setpoints need to be changed for bypassing, the coincidence logic is automatically adjusted as described in subsection 7.2.1.1.12. The logic provides that the remaining redundant channels for that variable meet the single failure criterion. The two-out-of-four logic is automatically reinstated when the bypass is removed.

7.2.1.2.5 Design Basis: Reactor Trips for Malfunctions, Accidents, Natural Phenomena, or Credible Events (Paragraph 4.7 and 4.8 of IEEE-603-1991)

There are no reactor trip functions that directly shutdown the reactor on occurrence of either natural phenomena (such as seismic flood or wind) or internal events (such as fire or pipe whip). The operator can trip the reactor at any time by actuating the manual reactor trip.

Functional diversity is used to determine the reactor trips for accident conditions. Generally, two or more reactor trips occur for the transients analyzed in the accident analyses.

For example, protection is provided for the complete loss of coolant flow event by low reactor coolant pump speed and by low coolant flow reactor trips. Complete reliance is not made on a single reactor trip terminating a given event. Table 15.0-6 lists the reactor trips and the conditions which normally result in each trip.

Redundancy provides confidence that reactor trips are generated on demand, even when the protection system is degraded by a single failure. Reactor trips are four-way redundant. The single failure criterion is met even if one channel is bypassed, as discussed in subsection 7.2.1.1.12. More than one bypass is not allowed.

7.2.1.3 System Drawings

Functional diagrams of the reactor trip function are provided in Figure 7.2-1.

7.2.2 Analyses

7.2.2.1 Failure Modes and Effects Analysis (FMEA)

The AP1000 protection system is similar to the AP600 protection system. A failure modes and effects analysis was performed on the AP600 protection and safety monitoring system. Through the process of examining the feasible failure modes, it was concluded that the AP600 protection system maintains safety functions during single point failures. The AP600 failure modes and effects analysis is documented in Reference 1. The Common Q failure modes and effects analysis

is documented in Reference 3 and also concludes that the protection system maintains safety functions during single point failures.

7.2.2.2 Conformance of the Reactor Trip Function to Applicable Criteria

Reactor trip is a protective function generated by the AP1000 protection and safety monitoring system. Requirements addressing equipment in the protection and safety monitoring system are presented in WCAP-15776 (Reference 2). The discussions presented in this subsection address only the functional aspects of reactor trip.

7.2.2.2.1 Conformance to the General Functional Requirements for Reactor Trip (Section 5 of IEEE-603-1991, GDC-13, GDC-20)

The protection and safety monitoring system initiates a reactor trip whenever a condition monitored by the system reaches a preset level. The reactor trips are listed in Table 7.2-2 and are discussed in subsection 7.2.1.1. The variables which are monitored for these trips are listed in subsection 7.2.1.2.2. Table 7.2-1 lists the ranges, accuracies, and response times for these variables. The reactor trip setpoints are listed in the technical specifications, Chapter 16.

As discussed in WCAP-15776 (Reference 2), the setpoints set into the protection and safety monitoring system equipment provide a margin to the safety limits which are assumed in the accident analyses. The safety limits are based on mechanical or hydraulic limitations of equipment or on heat transfer characteristics of the reactor core. While most setpoints used for reactor trip are fixed, there are continuously calculated setpoints for the overtemperature and overpower ΔT trips. Setpoints for reactor trip are selected on the basis of engineering design and safety studies. The setpoints provide a margin to allow for uncertainties and instrument errors.

The overtemperature and overpower conditions are not directly measurable quantities. However, the process variables that determine overtemperature and overpower conditions are sensed and evaluated. Small isolated changes in various process variables may not individually result in reaching a core safety limit. However, the combined variations over time may cause the overtemperature or overpower limit to be exceeded. The design concept for reactor trips takes cognizance of this situation by providing reactor trips associated with individual process variables in addition to the overtemperature and overpower ΔT safety limit trips. Process variable trips prevent reactor operation when a monitored value reaches a core or safety limit. Overtemperature and overpower ΔT trips provide protection for slow transients. Other trips, such as low flow or high flux, trip the reactor for rapid changes in flow or flux respectively.

Table 15.0-6 summarizes events which normally result in reactor trips.

7.2.2.2.2 Conformance to the Single Failure Criterion for Reactor Trip (Paragraph 5.1 of IEEE 603-1991, IEEE 379-2000)

A single failure in the protection and safety monitoring system or the reactor trip actuation divisions does not prevent a reactor trip, even when a reactor trip channel is bypassed for test or maintenance. Conformance of the equipment to this requirement is discussed in WCAP-15776 (Reference 2). In addition to the redundancy of equipment, diversity of reactor trip functions is incorporated. Most Condition II, III, or IV events requiring a reactor trip are protected by trips

from diverse parameters. For example, reactor trip, because of an uncontrolled rod cluster control assembly bank withdrawal at power, may occur on power range high neutron flux, overtemperature, overpower, pressurizer high pressure or pressurizer high water level. Reactor trip on complete loss of reactor coolant flow may occur on low flow or from the diverse parameter of low reactor coolant pump speed.

7.2.2.2.3 Conformance to the Requirements Covering Control and Reactor Trip Interactions (Paragraphs 5.6 and 6.3 of IEEE 603-1991, GDC-24)

The AP1000 is designed to permit maneuvering of the plant in response to normal power generation demands without causing a reactor trip. The plant control system attempts to keep the reactor operating away from any safety limit. However, the selection of the reactor trip setpoints does not take credit for such control actions. The accident analyses in Chapter 15 assumes that the plant is at normal operation commensurate with the operating mode at the onset of the accident. If a control system action leads to more conservative results, that assumption is made. If failure of a control system to work leads to more conservative results, that assumption is made. In this way, reactor trips do not depend on control system actions.

As stated in subsection 7.7.1.12, it is considered advantageous to use certain protection data for control functions. Isolation devices are incorporated into the protection system to prevent control system failures from degrading the performance of the protection system.

Failures in a protection channel monitoring a variable that is also used for control do not result in control system actions requiring protection by the redundant channels monitoring that variable. This is discussed in subsection WCAP-15776 (Reference 2).

7.2.2.2.4 Conformance to Requirements on the Derivation of System Inputs for Reactor Trip (Paragraph 6.4 of IEEE 603-1991)

To the extent feasible, inputs used for reactor trip are derived from signals that are direct measurements of the desired variables. Two exceptions exist, overtemperature and overpower, which cannot be directly measured. The process variables that do affect these parameters can be measured and they are used to continuously calculate the setpoints.

The overtemperature ΔT trip setpoint is calculated from pressurizer pressure, reactor coolant temperature, and nuclear axial power shape. The setpoint is compared against measured ΔT.

Overpower ΔT is calculated from reactor coolant temperature and the nuclear axial power shape in the core. This value is compared against measured ΔT.

The overtemperature and overpower ΔT trips are described in subsection 7.2.1.1.3.

7.2.2.2.5 Conformance to Requirements on Bypassing of Reactor Trip Functions (Paragraph 5.8, 5.9, 6.6, and 6.7 of IEEE 603-1991)

With the exception of the manual reactor trips, reactor trip channels and the reactor trip actuation divisions are permitted to be bypassed as described in WCAP-15776 (Reference 2).

Operating bypasses for reactor trips are described in subsection 7.2.1.1.11.

7.2.2.2.6 Conformance to Requirements on Multiple Setpoints Used for Reactor Trips (Paragraph 6.8.2 of IEEE 603-1991)

For monitoring neutron flux, multiple setpoints are used. When a more restrictive trip setting becomes necessary to provide adequate protection for a particular mode of operation or set of operating conditions, the protection and safety monitoring system hardware and software are designed to provide positive means or administrative control to ensure that the more restrictive trip setpoint is used. The hardware and software used to prevent improper use of less restrictive trip settings are considered part of the protection and safety monitoring system.

7.2.2.2.7 Conformance to the Requirement for Completion of Reactor Trip Once Initiated (Paragraph 5.2 of IEEE 603-1991, Regulatory Guide 1.62)

Once initiated, reactor trips proceed to completion. Return to operation requires deliberate operator action to reset the reactor trip circuit breakers that are opened by the reactor trip signal. The circuit breakers cannot be closed while the reactor trip signals are present from the respective protection and safety monitoring system division. A manual control is provided in the main control room for resetting the reactor trip signals following a reactor trip. Refer also to WCAP-15776 (Reference 2).

7.2.2.2.8 Conformance to the Requirement to Provide for Manual Initiation of Reactor Trip (Paragraph 6.2 of IEEE 603-1991, Regulatory Guide 1.62)

The reactor is tripped by actuating one of two manual reactor trip controls from the main control room. The reactor is also tripped upon manual actuation of the automatic depressurization system, manual core makeup tank injection, or upon manual safeguards actuation. These reactor trips are described in subsections 7.2.1.1.7, 7.2.1.1.8, 7.2.1.1.9, and 7.2.1.1.10. Refer also to WCAP-15776 (Reference 2).

7.2.3 Combined License Information

Combined License applicants referencing the AP1000 certified design will provide an FMEA for the protection and safety monitoring system. The FMEA will include a Software Hazards Analysis. This FMEA will provide the basis for those Technical Specification Completion Times that rely on an FMEA for their basis.

7.2.4 References

1. WCAP-13594(P), WCAP-13662 (NP), “FMEA of Advanced Passive Plant Protection System,” Revision 1, June 1998.

2. WCAP-15776, “Safety Criteria for the AP1000 Instrument and Control Systems,” April 2002.

3. CENPD-396-P, Appendix 3, Rev. 1, “Common Qualified Platform, Digital Plant Protection System,” May 2000.

Table 7.2-1 (Sheet 1 of 3)

REACTOR TRIP VARIABLES, LIMITS, RANGES, AND ACCURACIES
(DESIGN BASIS FOR REACTOR TRIP)
(NOMINAL)

Protective Functions	Variables To Be Monitored	Range of Variables	Typical Accuracy	Typical Response Time (Sec)(1)
Source Range High Neutron Flux	Neutron flux	6 decades of neutron flux: 1 to 10^6 counts per second	±11.0% of span	0.2
Intermediate Range High Neutron Flux	Neutron flux	8 decades of neutron flux overlapping source range by 2 decades and including 100% power	±12.5% of span	0.2
Power Range High Neutron Flux (Low Setting)	Neutron flux	1 to 120% of full power	±7.0% of span	0.2
Power Range High Neutron Flux (Hi-Setting)	Neutron flux	1 to 120% of full power	±7.0% of span	0.2
Power Range High Positive Flux Rate	Neutron flux	1 to 120% of full power	±1.0% of span	0.2 (step input of 20% full power)
Overtemperature ΔT			±11.5% of ΔT span	7.0 (T_{avg} or ΔT)
	Reactor coolant inlet temp. (T_{cold})	490° to 610°F	±2.5% of span	6.0
	Reactor coolant outlet temp. (T_{hot})	530° to 650°F	±3.5% of span	6.0
	Pressurizer pressure	1700 to 2500 psig	±2.5% of span	1.5
	Neutron flux (difference between top and bottom power range detectors)	-60 to +60% (Δφ)		2.0

Table 7.2-1 (Sheet 2 of 3)

REACTOR TRIP VARIABLES, LIMITS, RANGES, AND ACCURACIES (DESIGN BASIS FOR REACTOR TRIP) (NOMINAL)

Protective Functions	Variables To Be Monitored	Range of Variables	Typical Accuracy	Typical Response Time (Sec)(1)
Overpower ΔT			±3.5% of ΔT span	7.0 (T_{avg} or ΔT)
	Reactor coolant inlet temp. (T_{cold})	490° to 610°F	±2.5% of span	6.0
	Reactor coolant outlet temp. (T_{hot})	530° to 650°F	±3.5% of span	6.0
	Neutron flux (difference between top and bottom power range detectors)	-60 to +60% (Δφ)	±7.0% of span	2.0
Pressurizer Low Pressure	Pressurizer pressure	1700 to 2500 psig	±2.5% of span	1.2
Pressurizer High Pressure	Pressurizer pressure	1700 to 2500 psig	±2.5% of span	1.2
Pressurizer High Water Level	Pressurizer water level	0-100% of entire cylindrical portion of pressurizer	±2.25% of span	1.6
Low Reactor Coolant Flow	Coolant flow	0 to 120% of rated flow	±3.0% of span	1.6
Low Reactor Coolant Pump Speed	Pump speed	0 to 120% of rated speed	±0.2% of span	0.42(2)
Low Steam Generator Water Level	Steam generator water level	0-100% of span (narrow range taps)	±2.0% of span	1.6
High Steam Generator Water Level	Steam generator water level	0-100% of span (narrow range taps)	±2.0% of span	1.6
Reactor Coolant Pump High Bearing Water Temperature	Reactor coolant pump bearing water temperature	70°-450°F	±1.0% of span	2.0

Table 7.2-1 (Sheet 3 of 3)

REACTOR TRIP VARIABLES, LIMITS, RANGES, AND ACCURACIES (DESIGN BASIS FOR REACTOR TRIP) (NOMINAL)

Protective Functions	Variables To Be Monitored	Range of Variables	Typical Accuracy	Typical Response Time (Sec)(1)
Automatic or Manual Safeguards Actuation	See Table 7.3-4	See Table 7.3-4	See Table 7.3-4	See Table 7.3-4
Manual Reactor Trip	Switch position	N/A	N/A	N/A
Automatic or Manual Depressurization System Actuation	See Table 7.3-4	See Table 7.3-4	See Table 7.3-4	See Table 7.3-4
Automatic or Manual Core Makeup Tank Injection	See Table 7.3-4	See Table 7.3-4	See Table 7.3-4	See Table 7.3-4
Reference Leg Temperature Compensation(3)	Ref. leg temperature	100°-700°F	±3.0% of span	1.5

Notes:

1. Time from step change of the variable being monitored from 5% below to 5% above the setpoint. Value defined until the signal reaches the reactor trip breakers.
2. The time delay is the time to generate a trip after the pump speed has reached the trip setpoint during a speed decrease which is linear with respect to time.
3. This temperature compensation is not a protective function per se; however, these signals provide density compensation used in the pressurizer high water level protective function.

Table 7.2-2 (Sheet 1 of 2)

REACTOR TRIPS

Reactor Trip[1]	**No. of Channels**	**Division Trip Logic**	**Bypass Logic**	**Permissives and Interlocks (See Table 7.2-3)**
Source Range High Neutron Flux Reactor Trip	4	2/4	Yes[2]	P-6, P-10
Intermediate Range High Neutron Flux Reactor Trip	4	2/4	Yes[2]	P-10
Power Range High Neutron Flux (Low Setpoint) Trip	4	2/4	Yes[2]	P-10
Power Range High Neutron Flux (High Setpoint) Trip	4	2/4	Yes[2]	----
High Positive Flux Rate Trip	4	2/4	Yes[2]	----
Reactor Coolant Pump Bearing Water	16 (4/pump)	2/4 in any single pump 2/4 in 2/4 pumps	Yes[2] Yes[2]	P-8 P-10
Overtemperature ΔT	4 (2/loop)	2/4	Yes[2]	----
Overpower ΔT	4 (2/loop)	2/4	Yes[2]	----
Pressurizer Low Pressure Trip	4	2/4	Yes[2]	P-10
Pressurizer High Pressure Trip	4	2/4	Yes[2]	----
Pressurizer High Water Level Trip	4	2/4	Yes[2]	P-10
Low Reactor Coolant Flow	8 (4/hot leg)	2/4 in either hot leg 2/4 in both legs	Yes[2] Yes[2]	P-8 P-10
Reactor Coolant Pump Underspeed	4 (1/pump)	2/4	Yes[2]	P-10
Low Steam Generator Water Level	4/steam generator	2/4 in any steam generator	Yes[2]	----
High-2 Steam Generator Water Level	4/steam generator	2/4 in any steam generator	Yes[2]	P-11

Table 7.2-2 (Sheet 2 of 2)

REACTOR TRIPS

Reactor Trip[1]	No. of Channels	Division Trip Logic	Bypass Logic	Permissives and Interlocks (See Table 7.2-3)
Automatic Safeguards Actuation	4	2/4	Yes[2]	----
Automatic Depressurization System Actuation	4	2/4	Yes[2]	----
Automatic Core Makeup Tank Injection	4	2/4	Yes[2]	----
Manual Safeguards Actuation	2 switches	1/2 switches	No	----
Manual Depressurization System Actuation	4 switches	2/4 switches	No	----
Manual Core Makeup Tank Injection	2 switches	1/2 switches	No	----
Manual Reactor Trip	2 switches	1/2 switches	No	----

Notes:

1. Reactor Trip divisions are also bypassed with the logic as defined in 2. below.
2. Bypass Logic = 2/4 with no bypasses; 2/3 with 1 bypass; more than one bypass is not allowed.

---- No permissive or interlock.

Table 7.2-3 (Sheet 1 of 2)

REACTOR TRIP PERMISSIVES AND INTERLOCKS

Designation	Derivation	Function
P-6	Intermediate range neutron flux above setpoint	Allows manual block of source range reactor trip
$\overline{\text{P-6}}$	Intermediate range neutron flux below setpoint	Automatically resets source range reactor trip
P-8	Power range nuclear power above setpoint	Permits reactor trip on low flow or reactor coolant pump high bearing water temperature in a single loop
$\overline{\text{P-8}}$	Power range nuclear power below setpoint	Blocks reactor trip on low coolant flow or reactor coolant pump high bearing water temperature in a single loop
P-10	Power range nuclear power above setpoint	(a) Allows manual block of power range (low setpoint) reactor trip (b) Allows manual block of intermediate range reactor trip (c) Automatically blocks source range reactor trip (back-up to P-6) (d) Allows reactor trip on low coolant flow or reactor coolant pump high bearing water temperature in multiple loops (e) Allows reactor trip on low reactor coolant pump speed (f) Allows reactor trip on high pressurizer water level (g) Allows reactor trip on low pressurizer pressure

Table 7.2-3 (Sheet 2 of 2)

REACTOR TRIP PERMISSIVES AND INTERLOCKS

Designation	Derivation	Function
$\overline{\text{P-10}}$	Power range nuclear power below setpoint	(a) Prevents the block of power range (low setpoint) reactor trip (b) Prevents the block of intermediate range reactor trip (c) Permits manual reset of each source range channel reactor trip (d) Blocks reactor trip on low coolant flow or reactor coolant pump high bearing water temperature in multiple loops (e) Blocks reactor trip on low reactor coolant pump speed (f) Blocks reactor trip on high pressurizer water level (g) Blocks reactor trip on low pressurizer pressure
P-11	Pressurizer pressure below setpoint	Allows manual block of High-2 steam generator water level reactor trip
$\overline{\text{P-11}}$	Pressurizer pressure above setpoint	Automatically resets High-2 steam generator water level reactor trip
P-17(1)	Power range nuclear power negative rate below setpoint	Blocks automatic rod withdrawal
$\overline{\text{P-17}}$(1)	Power range nuclear power negative rate above setpoint	Permits automatic rod withdrawal

Note:

1. This interlock does not meet the July 1993 Final Policy Statement on Technical Specification Improvements criteria and is not included in the Technical Specifications.

Table 7.2-4

SYSTEM-LEVEL MANUAL INPUTS TO THE REACTOR TRIP FUNCTIONS

Manual Control	To Divisions				Figure 7.2-1 Sheet
Manual Reactor Trip Control #1	A	B	C	D	2 & 13
Manual Reactor Trip Control #2	A	B	C	D	2 & 13
Reactor Trip Reset	A	B	C	D	13
Source Range High Neutron Flux Block, Division A	A				3
Source Range High Neutron Flux Block, Division B		B			3
Source Range High Neutron Flux Block, Division C			C		3
Source Range High Neutron Flux Block, Division D				D	3
Intermediate Range High Neutron Flux Block, Division A	A				3
Intermediate Range High Neutron Flux Block, Division B		B			3
Intermediate Range High Neutron Flux Block, Division C			C		3
Intermediate Range High Neutron Flux Block, Division D				D	3
Power Range High Neutron Flux Block (Low Setpoint), Division A	A				3
Power Range High Neutron Flux Block (Low Setpoint), Division B		B			3
Power Range High Neutron Flux Block (Low Setpoint), Division C			C		3
Power Range High Neutron Flux Block (Low Setpoint), Division D				D	3
Manual Safeguards Actuation Control #1	A	B	C	D	2 & 11
Manual Safeguards Actuation Control #2	A	B	C	D	2 & 11
Manual Core Makeup Tank Injection Control #1	A	B	C	D	2 & 12
Manual Core Makeup Tank Injection Control #2	A	B	C	D	2 & 12
Manual Depressurization System Stages 1, 2 & 3 Actuation Controls #1 & 2	A	B	C	D	2 & 15
Manual Depressurization System Stages 1, 2 & 3 Actuation Controls #3 & 4	A	B	C	D	2 & 15

Note:
Controls are located in the main control room except as noted on the applicable sheet of Figure 7.2-1.

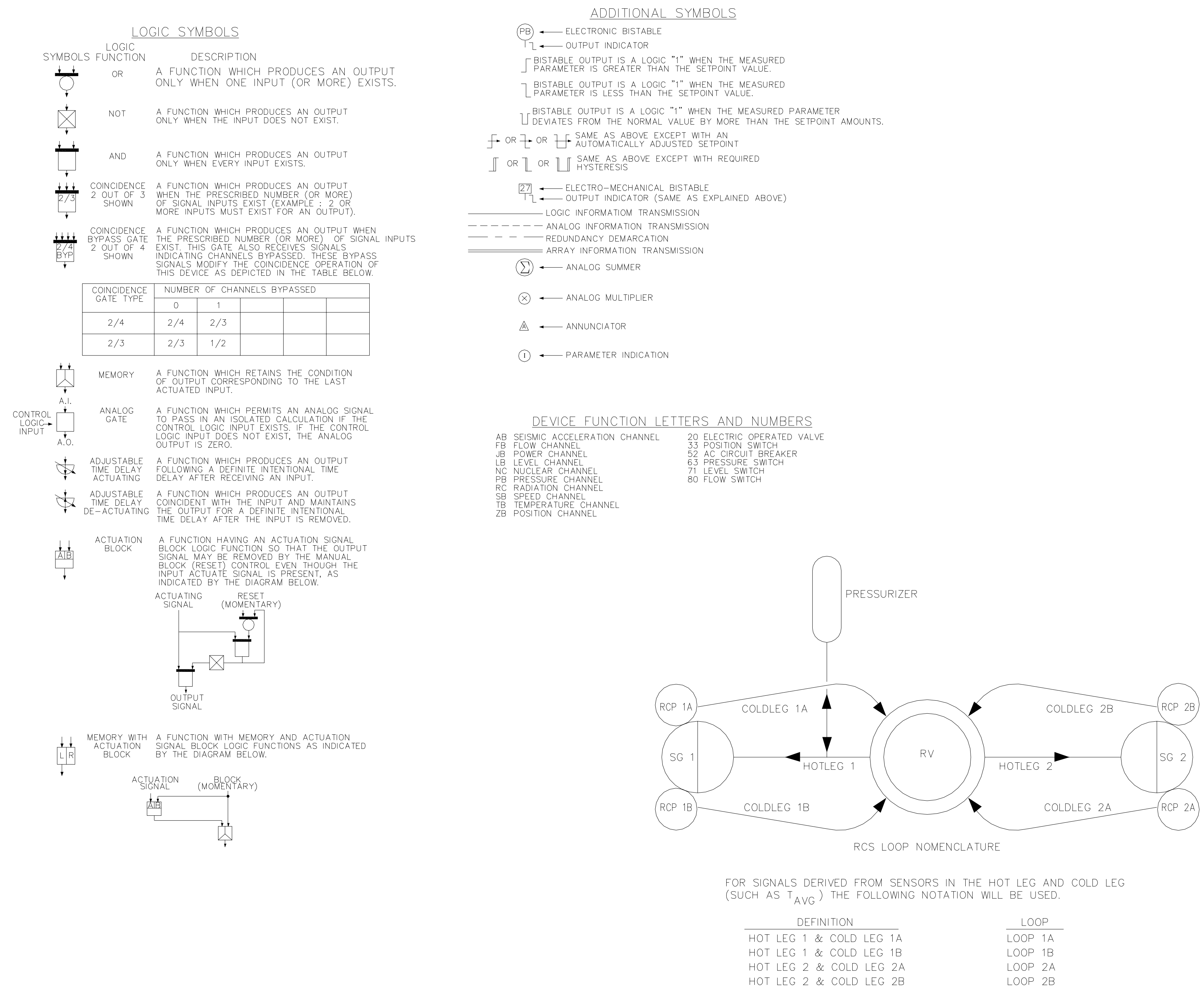


Figure 7.2-1 (Sheet 1 of 20)

Functional Diagram Index and Symbols

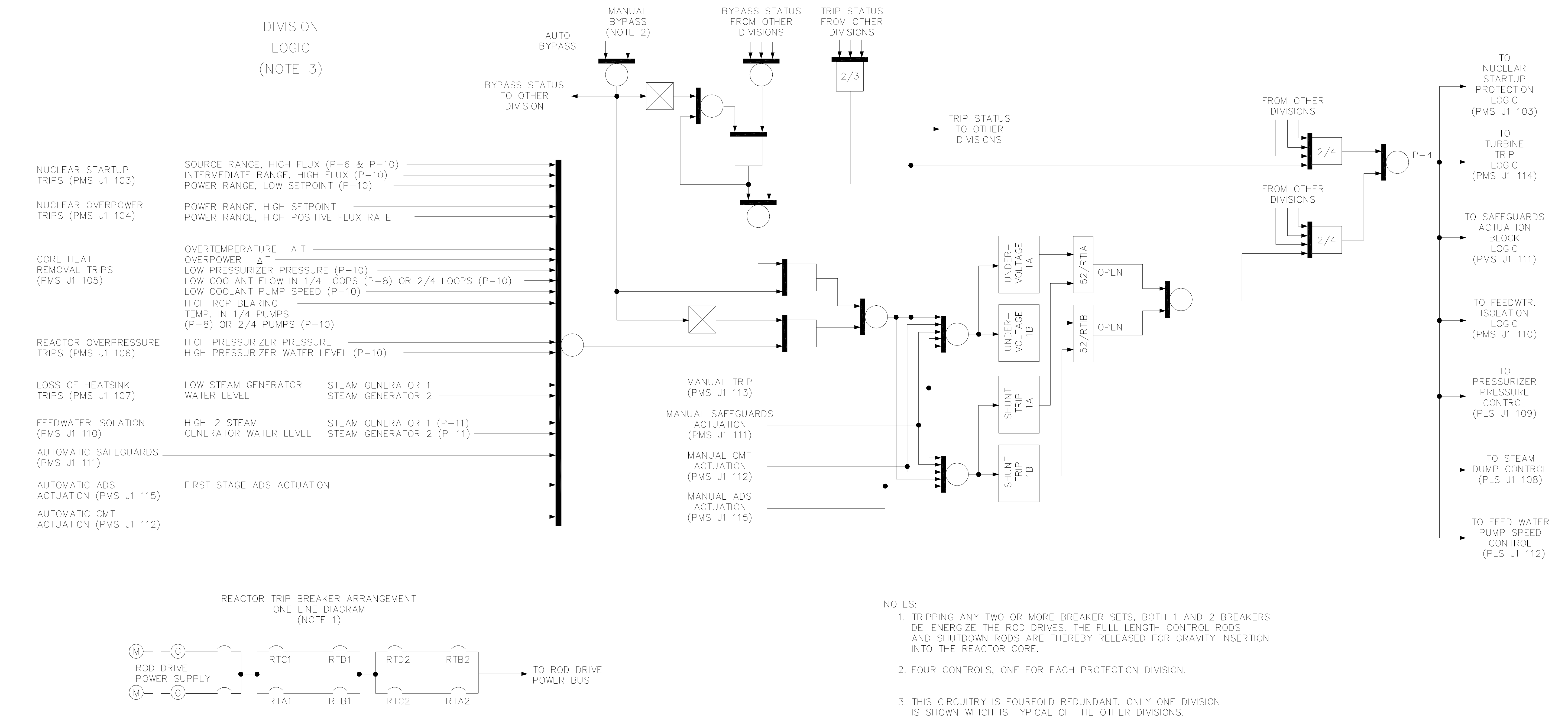


Figure 7.2-1 (Sheet 2 of 20)

Functional Diagram
Reactor Trip Functions

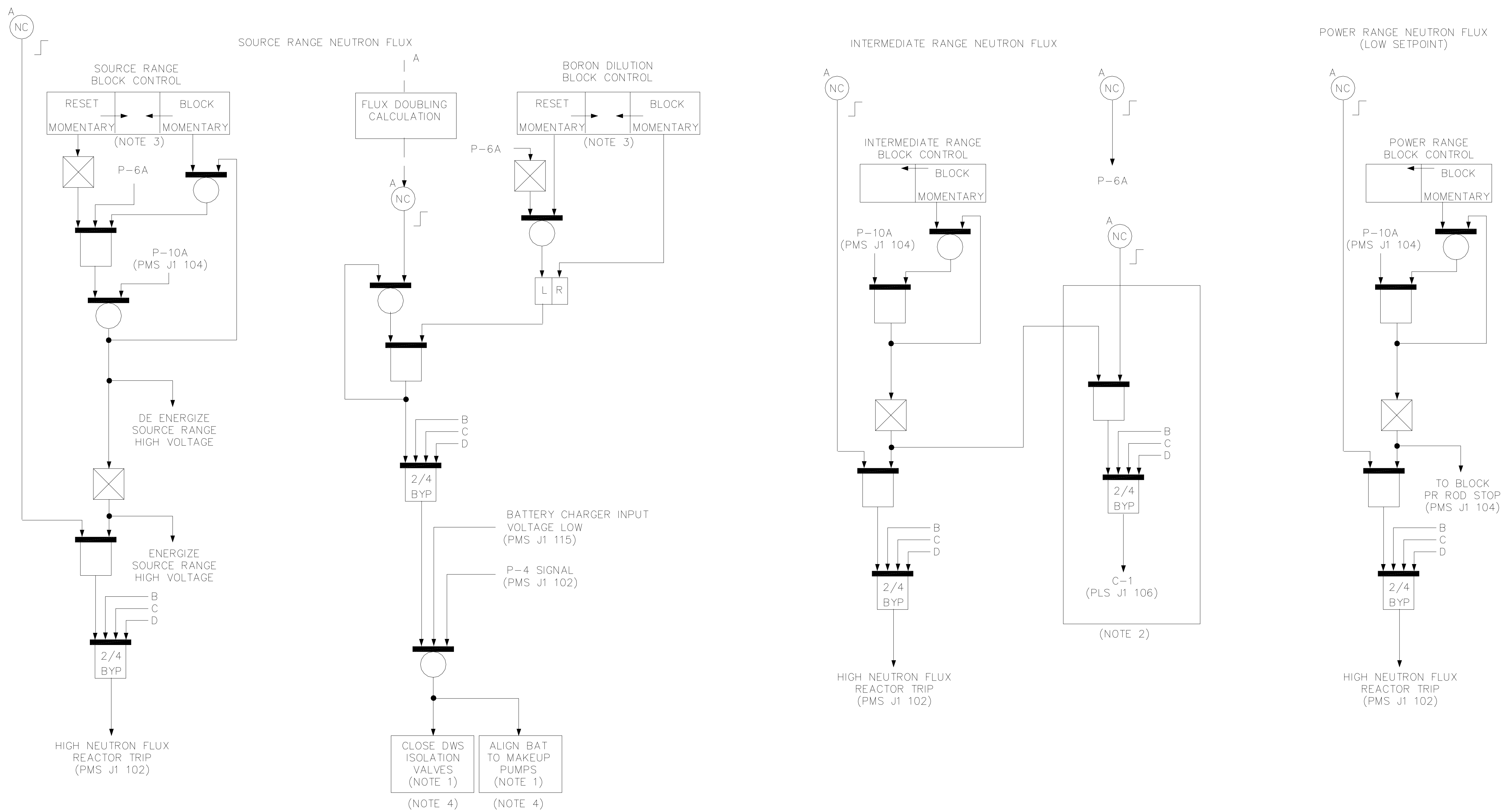
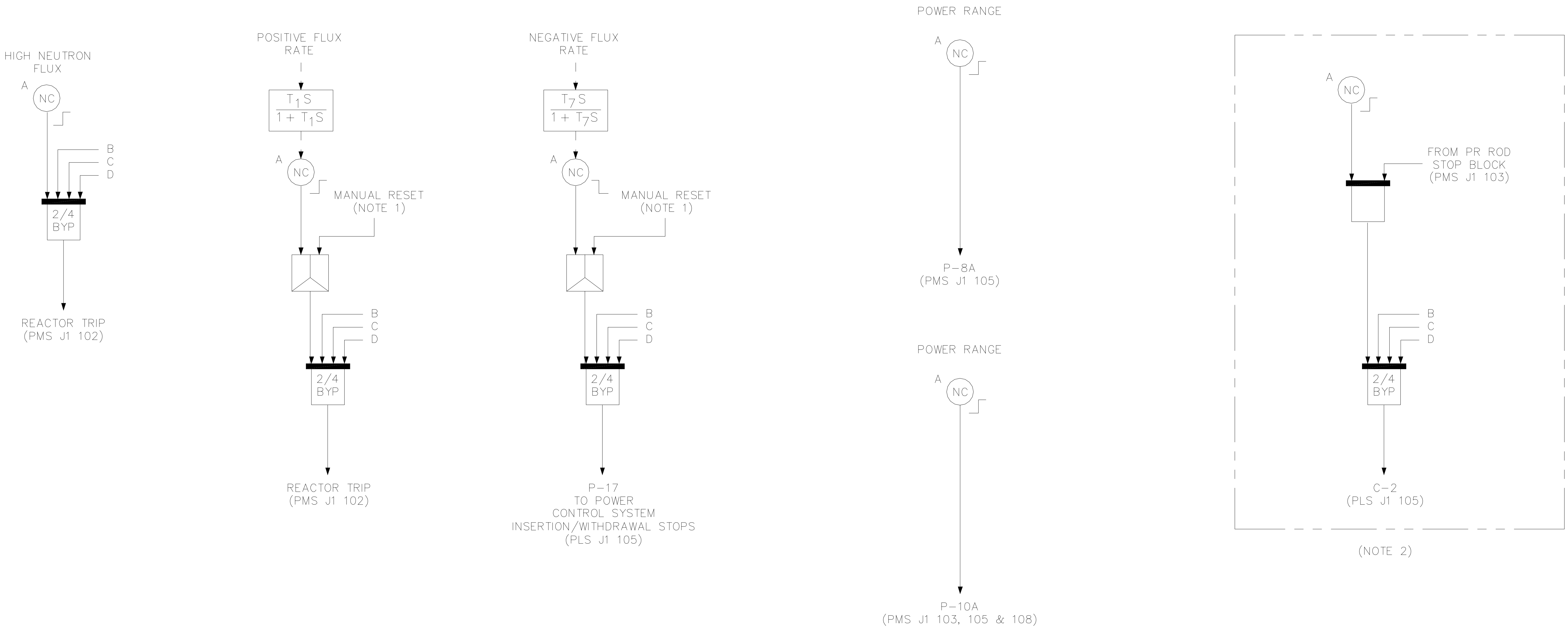


Figure 7.2-1 (Sheet 3 of 20)

Functional Diagram
Nuclear Startup Protection



NOTES:

1. FOUR MOMENTARY CONTROLS, ONE FOR EACH DIVISION.
2. THIS CIRCUIT DOES NOT PERFORM A SAFETY-RELATED FUNCTION.

Figure 7.2-1 (Sheet 4 of 20)

Functional Diagram
Nuclear Overpower Protection

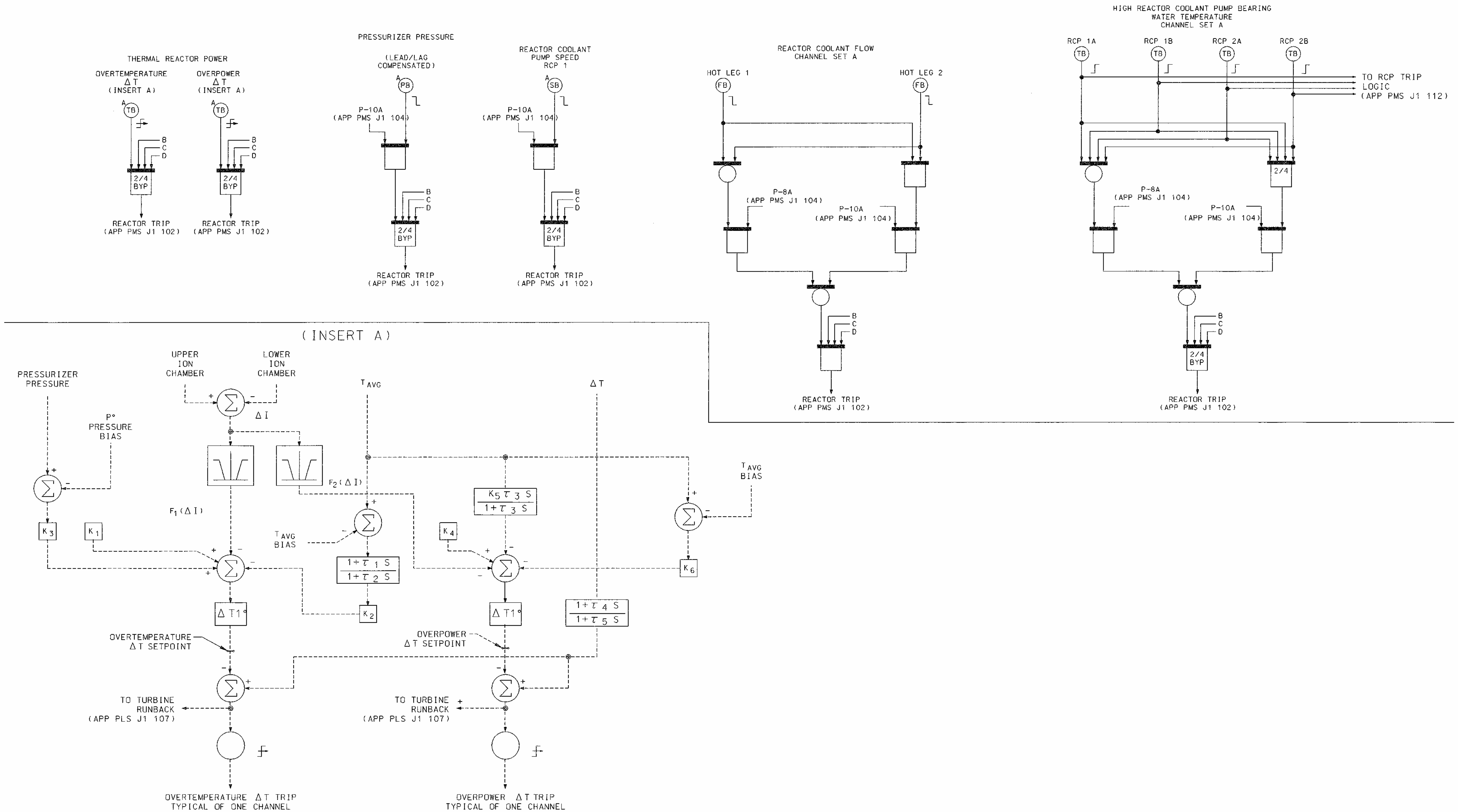
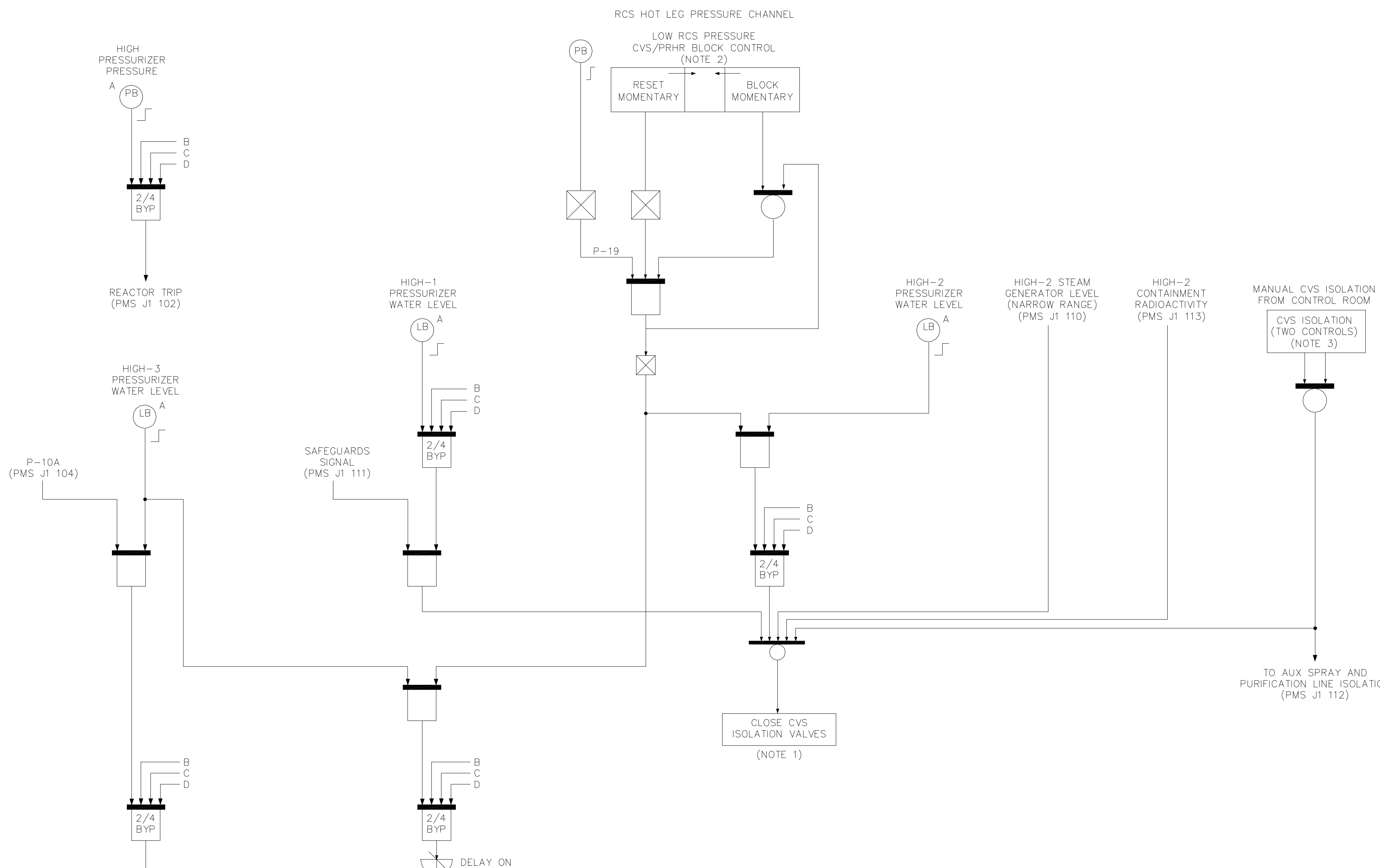


Figure 7.2-1 (Sheet 5 of 20)

Functional Diagram
Core Heat Removal Protection



NOTES:

1. COMPONENTS ARE ALL INDIVIDUALLY SEALED IN (LATCHED), SO THAT LOSS OF THE ACTUATION SIGNAL WILL NOT CAUSE THESE COMPONENTS TO RETURN TO THE CONDITION HELD PRIOR TO THE ADVENT OF THE ACTUATION SIGNAL.
2. SEPARATE MOMENTARY CONTROLS. ONE FOR EACH DIVISION.
3. TWO MOMENTARY CONTROLS, OPERATING EITHER CONTROL WILL ACTUATE ALL DIVISIONS.

Figure 7.2-1 (Sheet 6 of 20)

Functional Diagram
Primary Overpressure & Loss of Heat Sink Protection

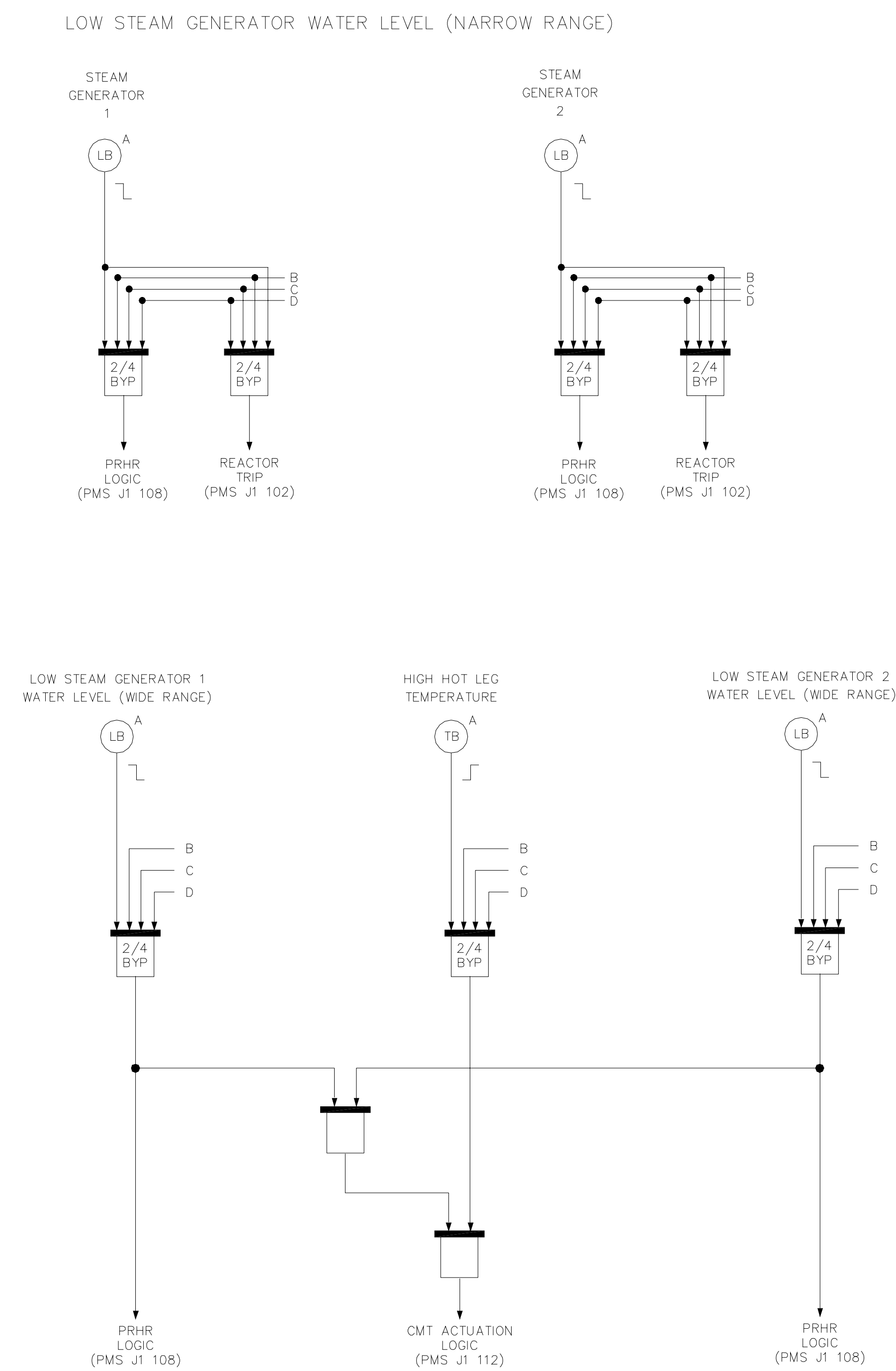


Figure 7.2-1 (Sheet 7 of 20)

Functional Diagram
Loss of Heat Sink Protection

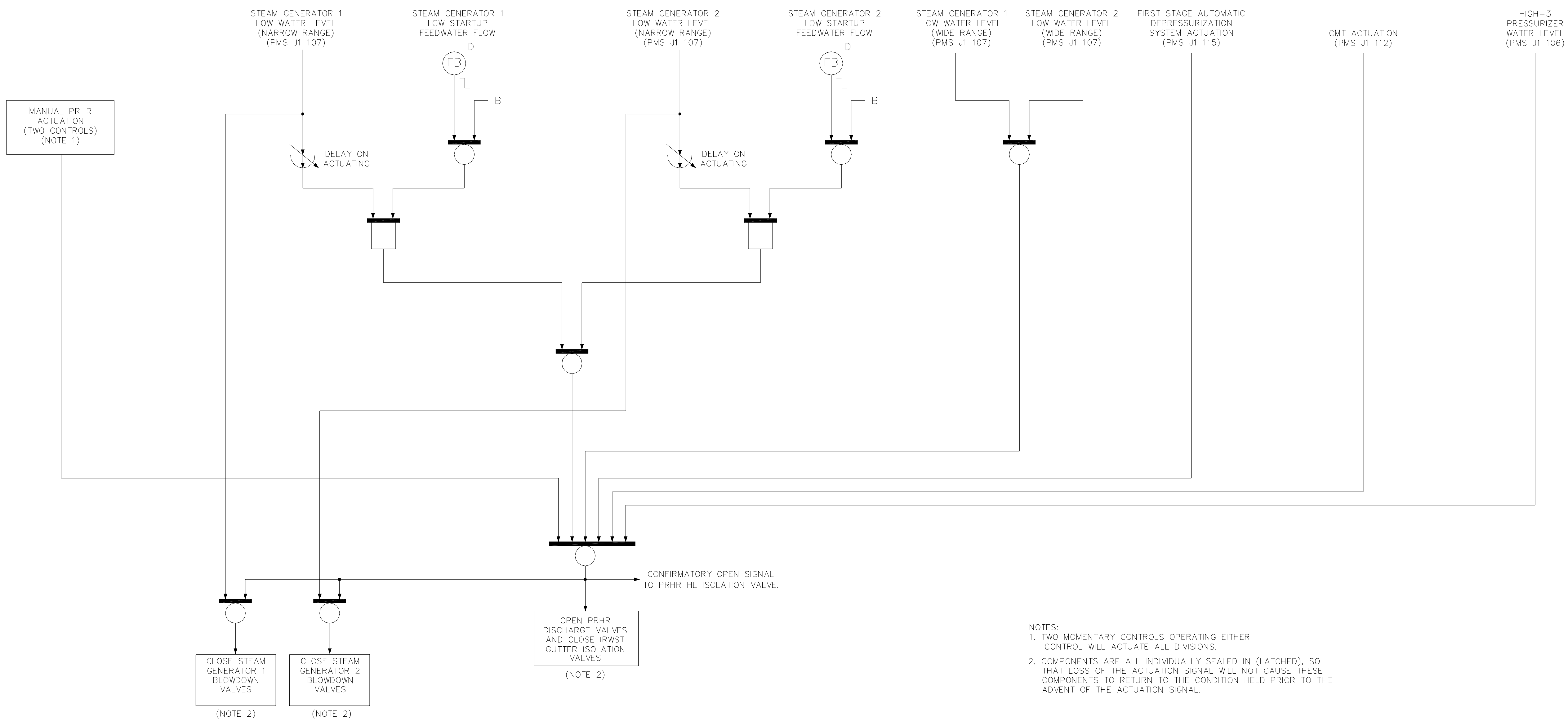
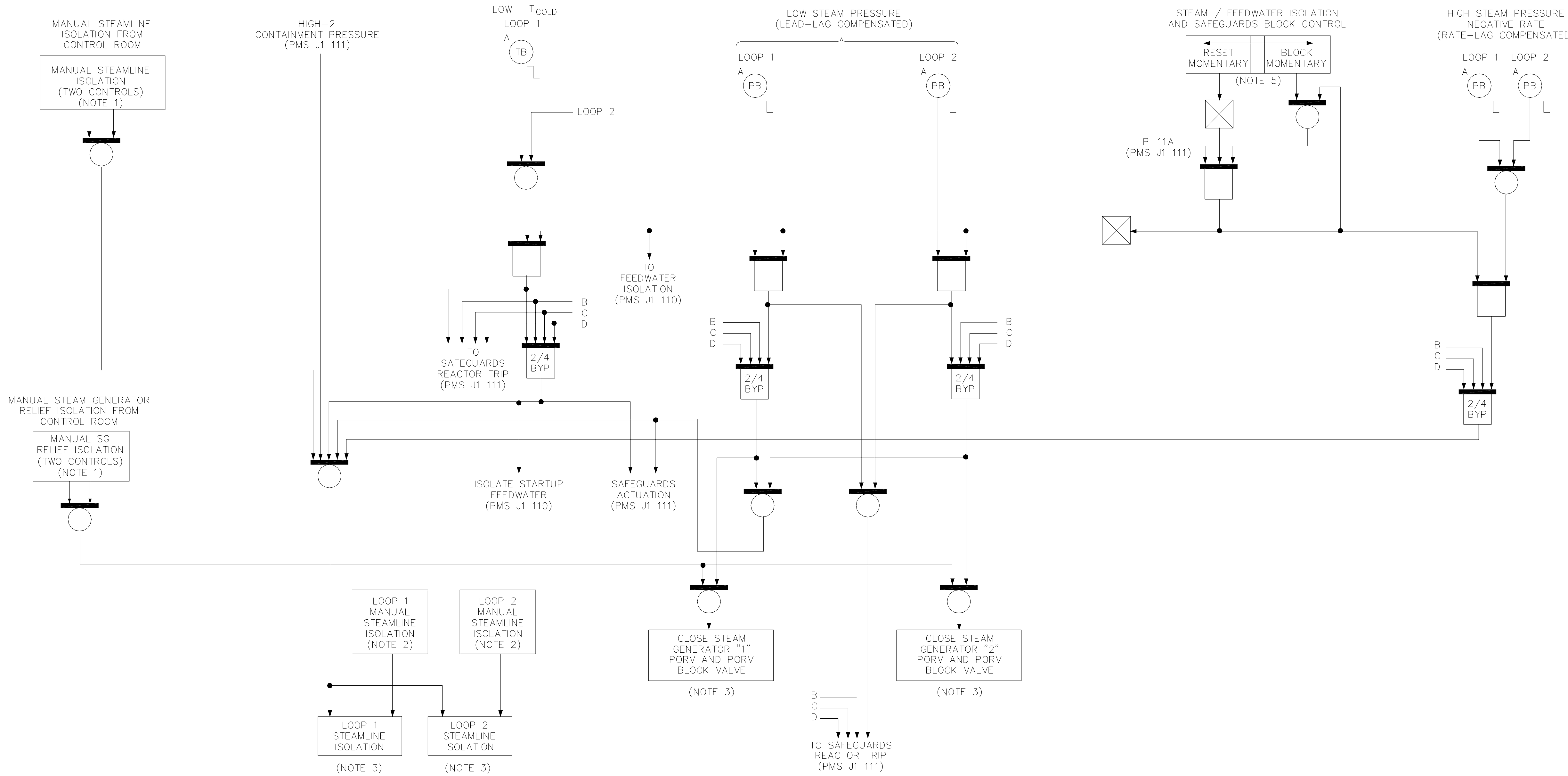


Figure 7.2-1 (Sheet 8 of 20)

Functional Diagram
Loss of Heat Sink Protection

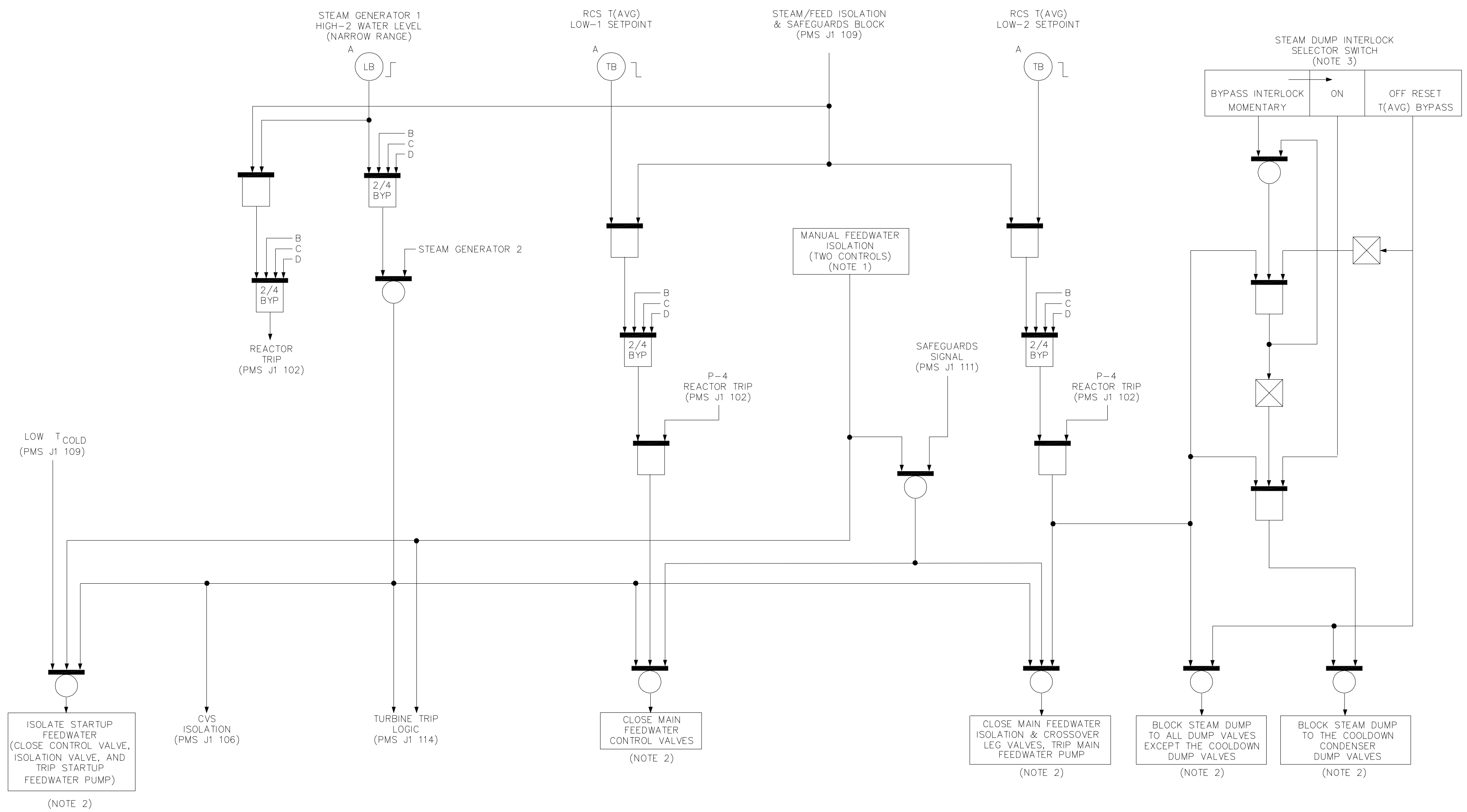


NOTES:

1. TWO MOMENTARY CONTROLS OPERATING EITHER CONTROL WILL ACTIVATE ALL DIVISIONS.
2. THESE CONTROLS ARE NOT REDUNDANT.
3. COMPONENTS ARE ALL INDIVIDUALLY SEALED IN (LATCHED), SO THAT LOSS OF THE ACTUATION SIGNAL WILL NOT CAUSE THESE COMPONENTS TO RETURN TO THE CONDITION HELD PRIOR TO THE ADVENT OF THE ACTUATION SIGNAL.

Figure 7.2-1 (Sheet 9 of 20)

Functional Diagram
Steamline Isolation

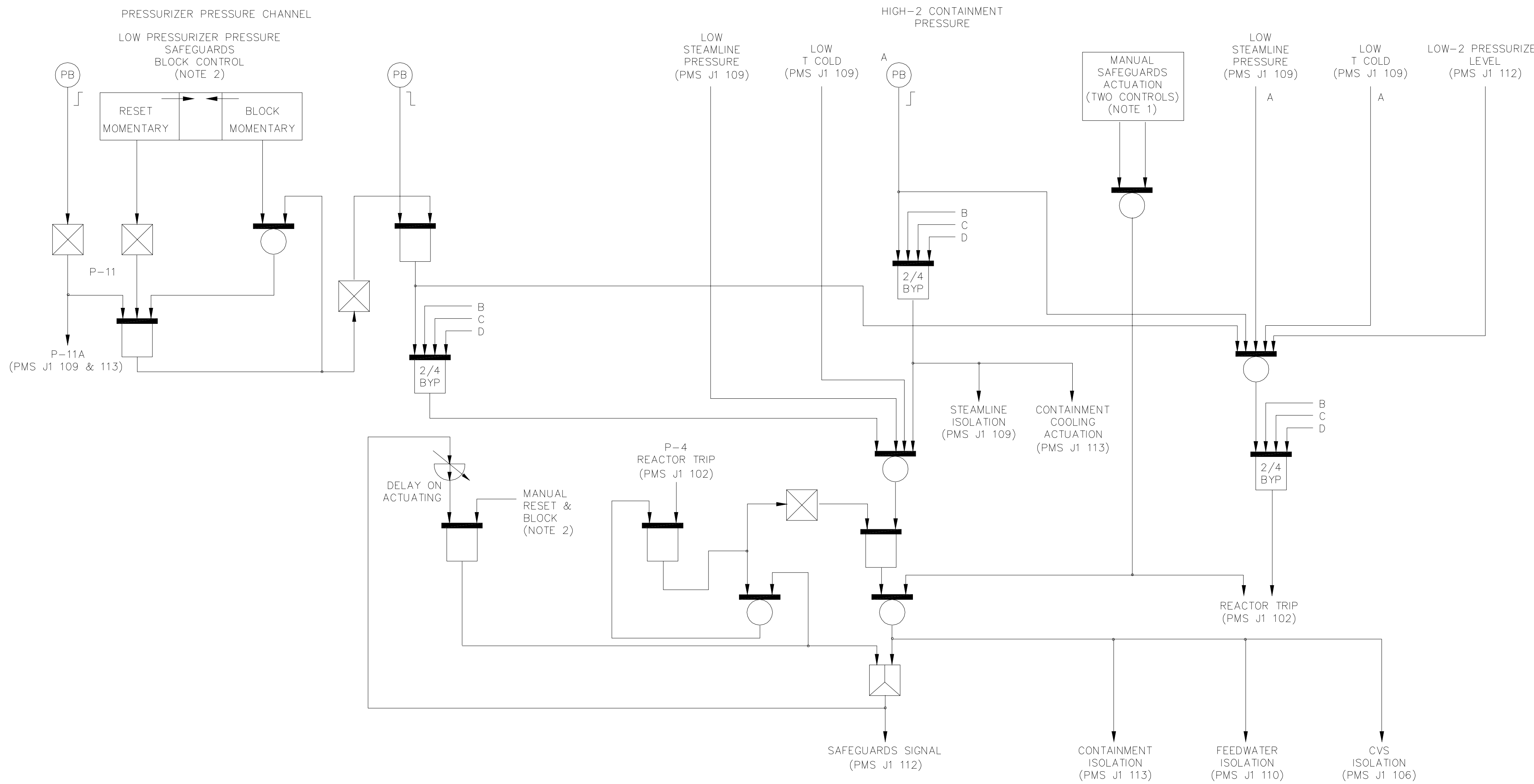


NOTES:

1. TWO MOMENTARY CONTROLS. OPERATING EITHER CONTROL WILL ACTUATE ALL DIVISIONS.
2. COMPONENTS ARE ALL INDIVIDUALLY SEALED IN (LATCHED), SO THAT LOSS OF THE ACTUATION SIGNAL WILL NOT CAUSE THESE COMPONENTS TO RETURN TO THE CONDITION HELD PRIOR TO THE ADVENT OF THE ACTUATION SIGNAL.
3. MOMENTARY CONTROLS, ONE FOR EACH DIVISION.

Figure 7.2-1 (Sheet 10 of 20)

Functional Diagram
Feedwater Isolation

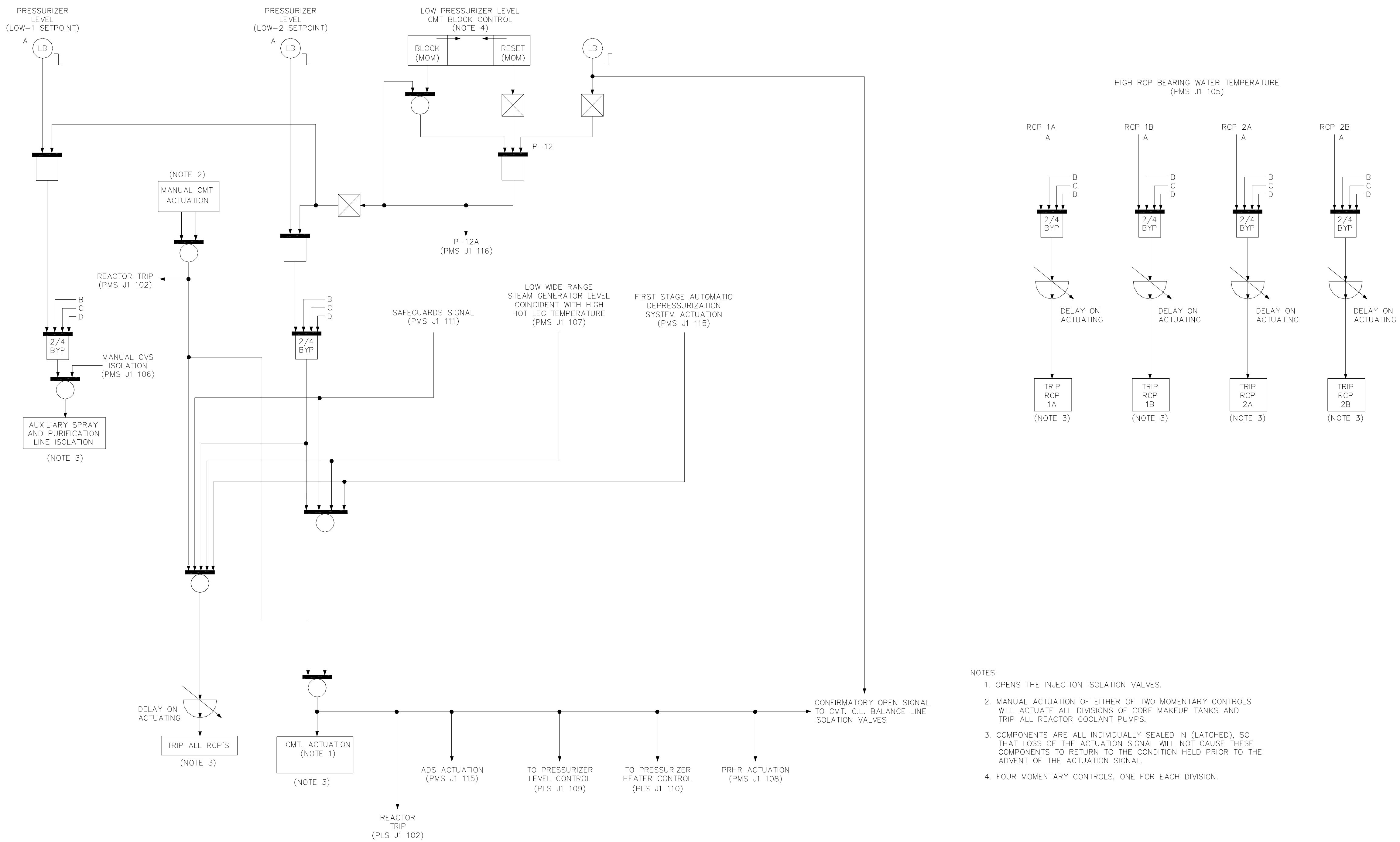


NOTES:

1. TWO MOMENTARY CONTROLS. OPERATING EITHER CONTROL WILL ACTUATE ALL DIVISIONS.
2. SEPARATE MOMENTARY CONTROLS. ONE FOR EACH DIVISION.

Figure 7.2-1 (Sheet 11 of 20)

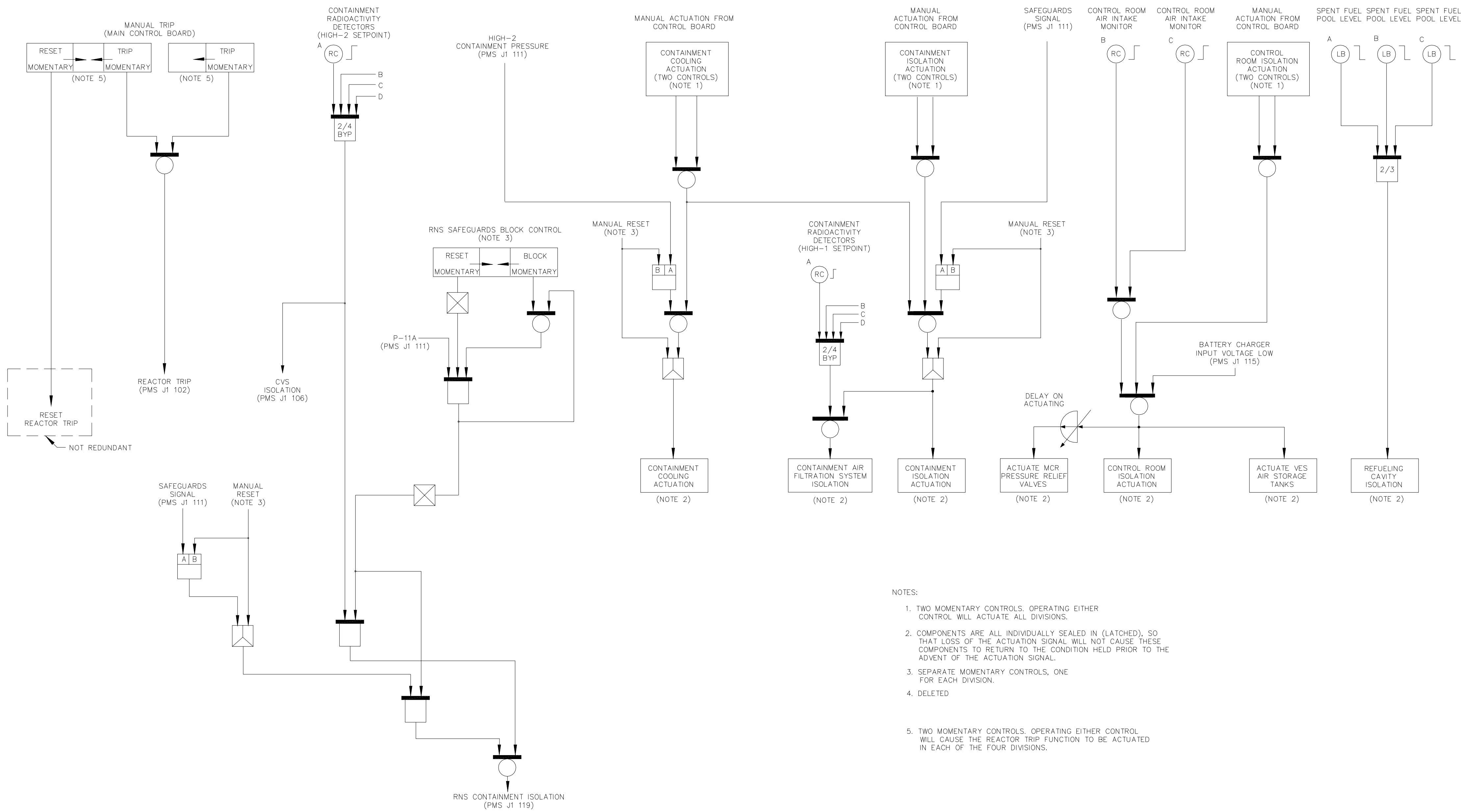
Functional Diagram
Safeguards Actuation



NOTES:
1. OPENS THE INJECTION ISOLATION VALVES.
2. MANUAL ACTUATION OF EITHER OF TWO MOMENTARY CONTROLS WILL ACTUATE ALL DIVISIONS OF CORE MAKEUP TANKS AND TRIP ALL REACTOR COOLANT PUMPS.
3. COMPONENTS ARE ALL INDIVIDUALLY SEALED IN (LATCHED), SO THAT LOSS OF THE ACTUATION SIGNAL WILL NOT CAUSE THESE COMPONENTS TO RETURN TO THE CONDITION HELD PRIOR TO THE ADVENT OF THE ACTUATION SIGNAL.
4. FOUR MOMENTARY CONTROLS, ONE FOR EACH DIVISION.

Figure 7.2-1 (Sheet 12 of 20)

Functional Diagram
Core Makeup Tank Actuation and Reactor Coolant Pump Trip

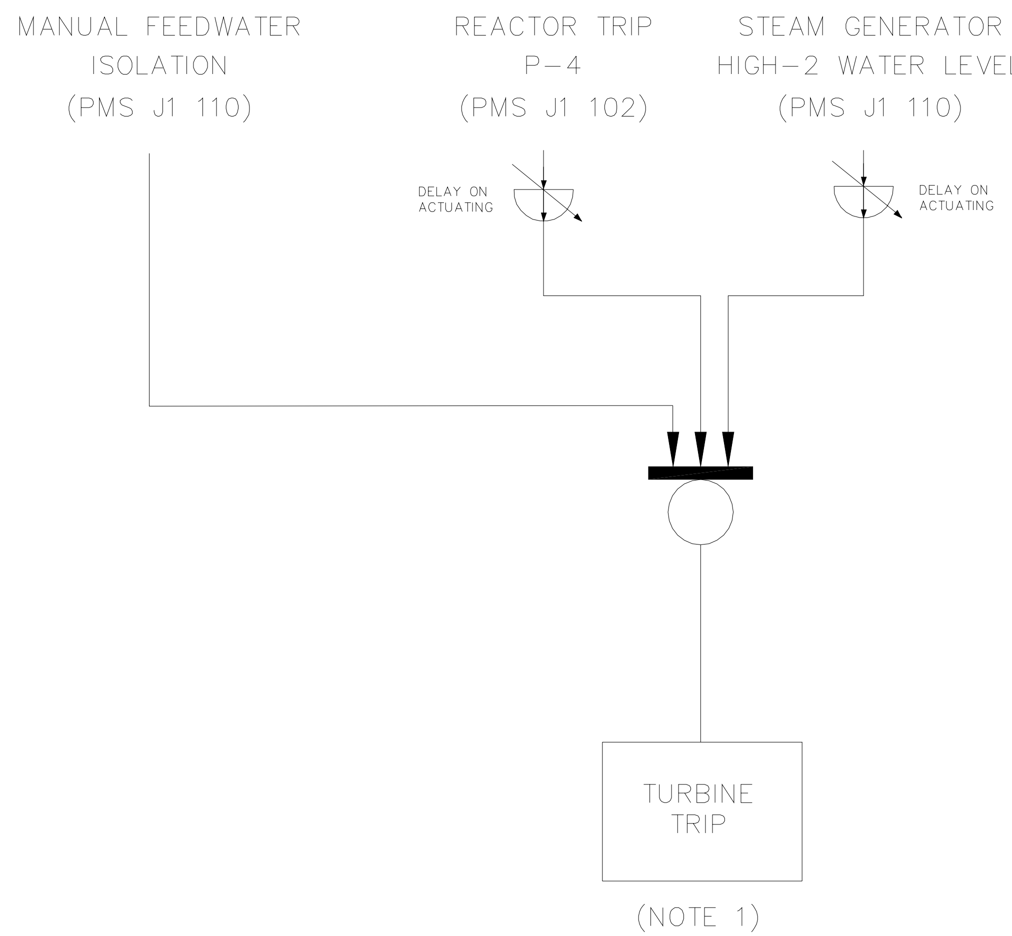


NOTES:

1. TWO MOMENTARY CONTROLS. OPERATING EITHER CONTROL WILL ACTUATE ALL DIVISIONS.
2. COMPONENTS ARE ALL INDIVIDUALLY SEALED IN (LATCHED), SO THAT LOSS OF THE ACTUATION SIGNAL WILL NOT CAUSE THESE COMPONENTS TO RETURN TO THE CONDITION HELD PRIOR TO THE ADVENT OF THE ACTUATION SIGNAL.
3. SEPARATE MOMENTARY CONTROLS, ONE FOR EACH DIVISION.
4. DELETED
5. TWO MOMENTARY CONTROLS. OPERATING EITHER CONTROL WILL CAUSE THE REACTOR TRIP FUNCTION TO BE ACTUATED IN EACH OF THE FOUR DIVISIONS.

Figure 7.2-1 (Sheet 13 of 20)

Functional Diagram
Containment and Other Protection



NOTES:

1. COMPONENTS ARE INDIVIDUALLY SEALED IN (LATCHED) SO THAT LOSS OF THE ACTUATION SIGNAL WILL NOT CAUSE THESE COMPONENTS TO RETURN TO THE CONDITION HELD PRIOR TO THE ADVENT OF THE ACTUATION SIGNAL.

Figure 7.2-1 (Sheet 14 of 20)

Functional Diagram
Turbine Trip

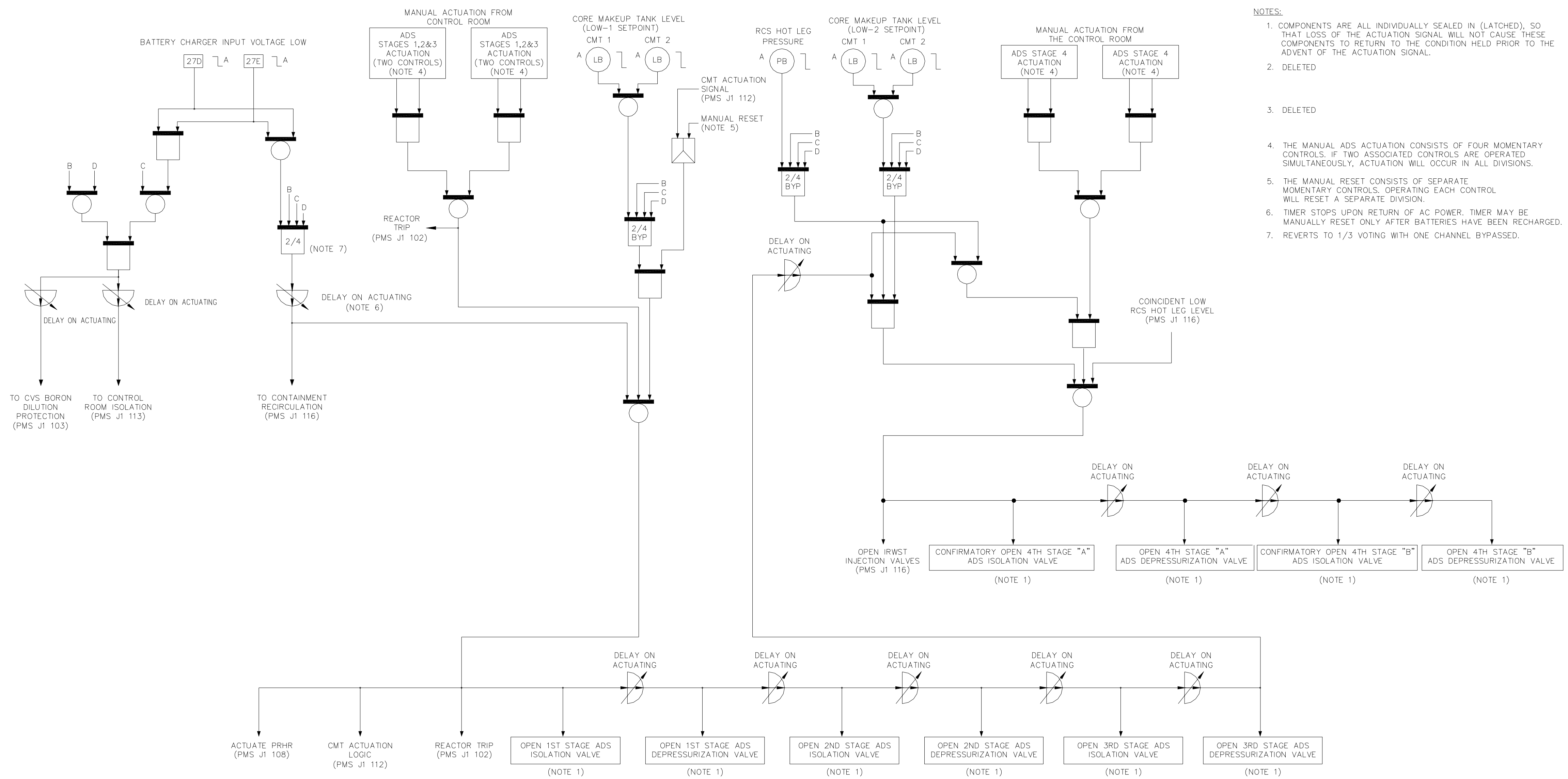
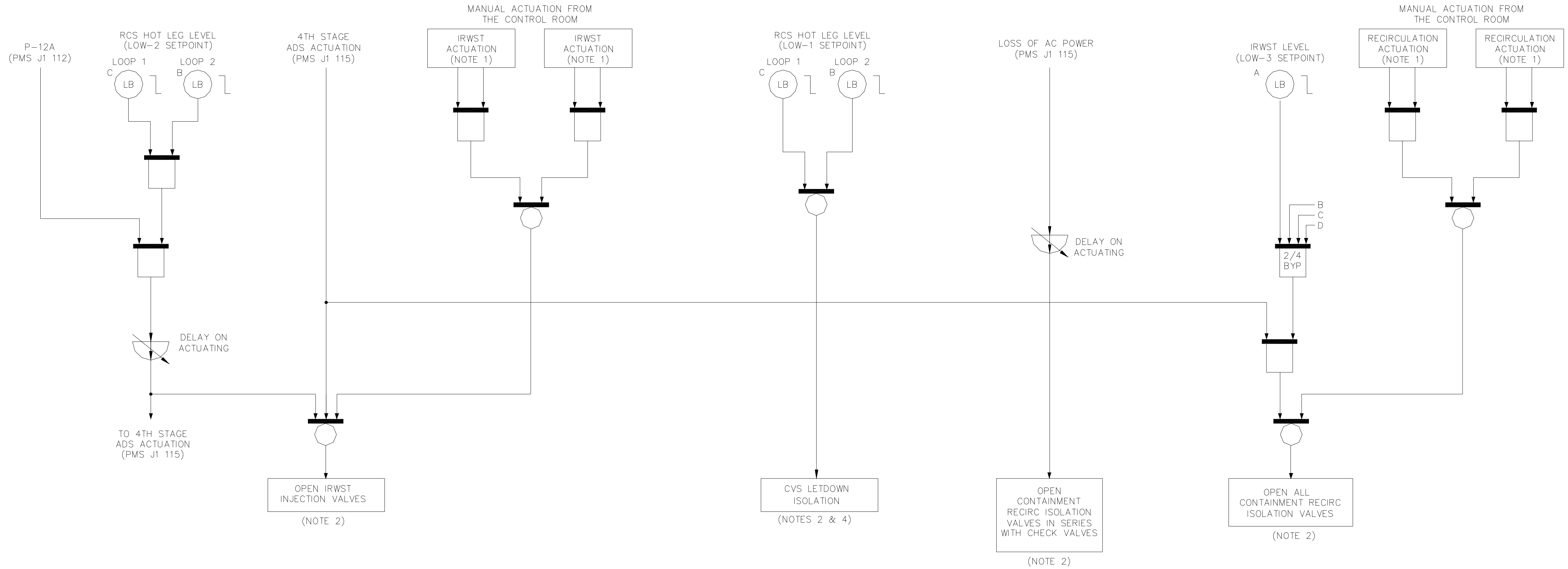


Figure 7.2-1 (Sheet 15 of 20)

Functional Diagram
Automatic RCS Depressurization Valve Sequencing

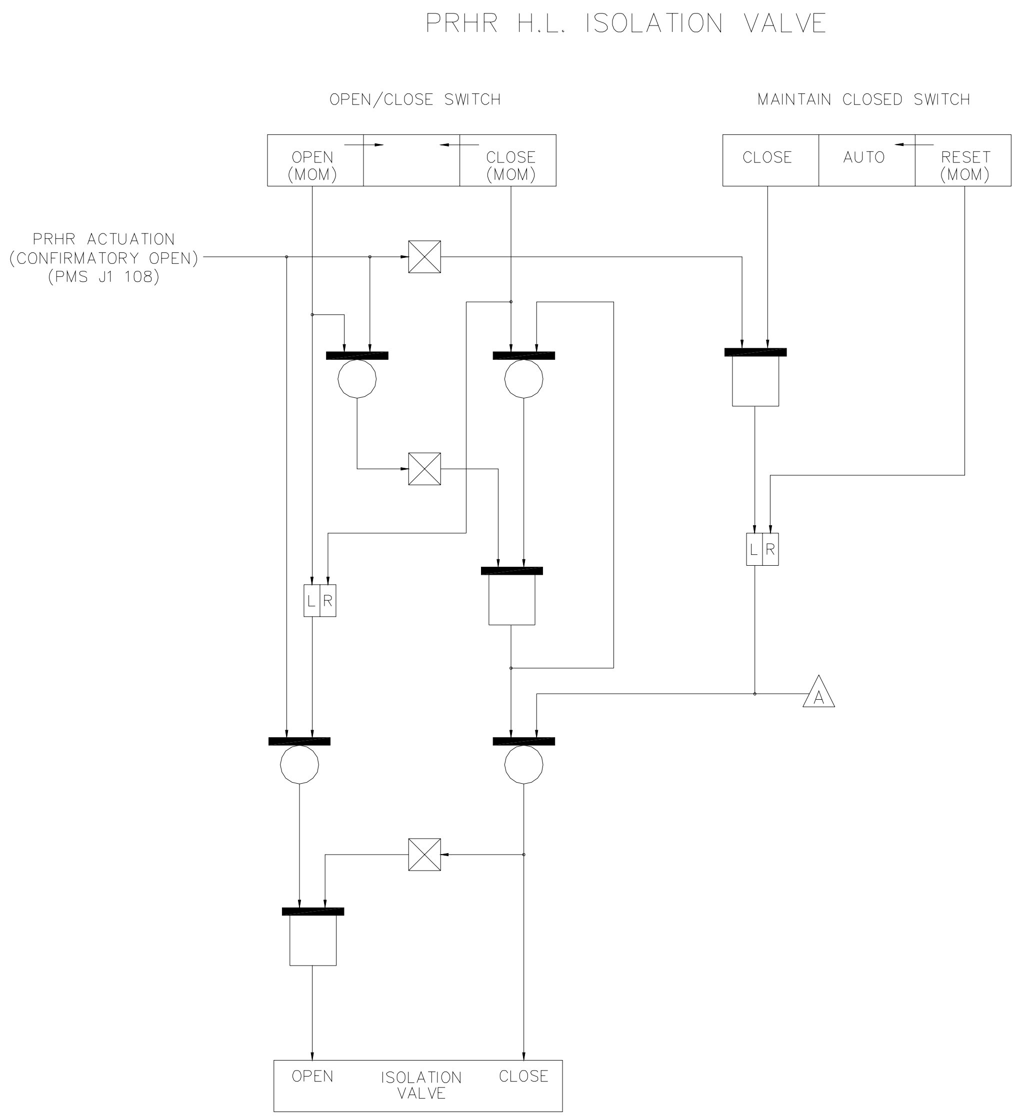


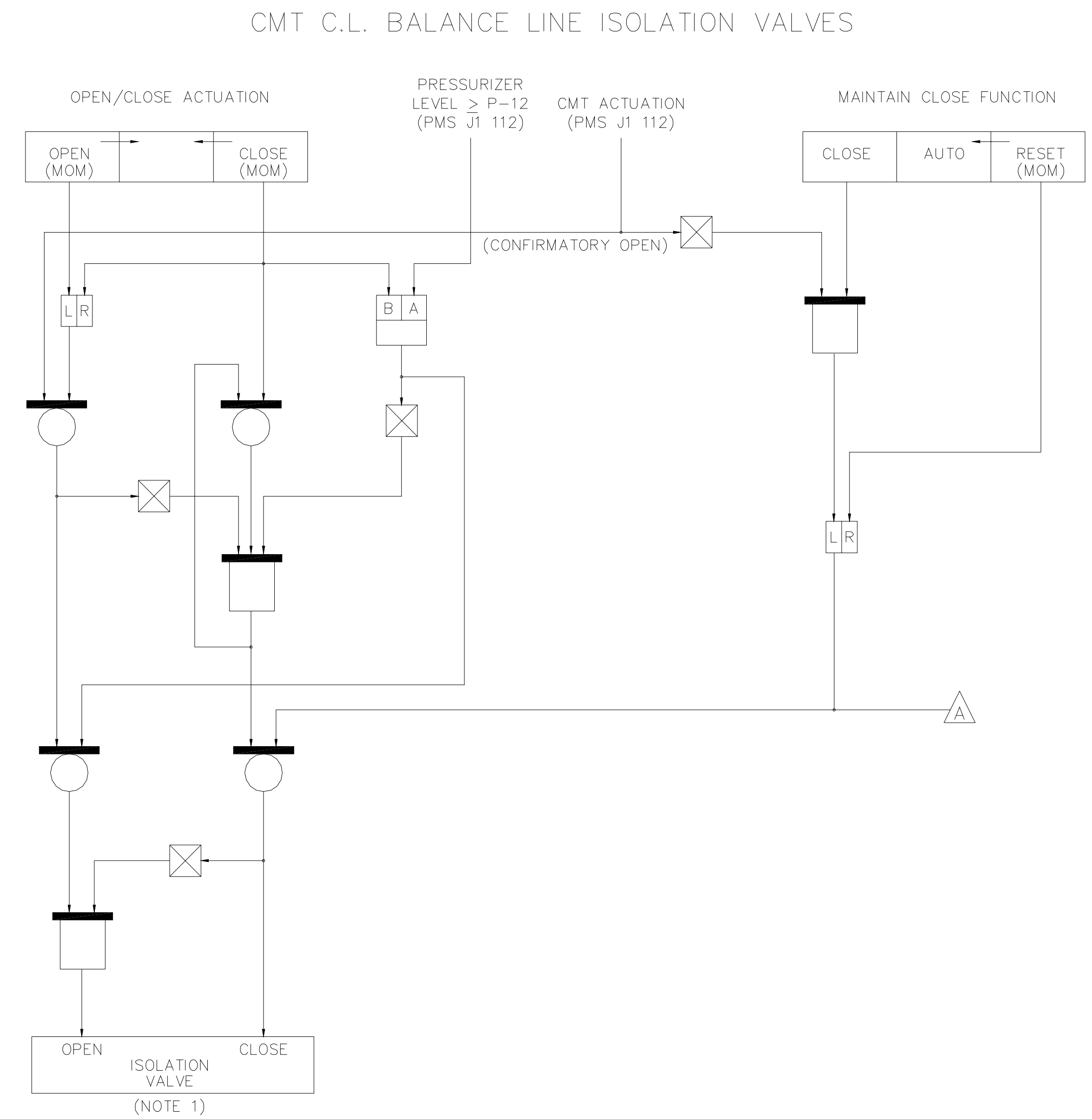
NOTES:

1. THE MANUAL ACTUATION CONSISTS OF FOUR MOMENTARY CONTROLS. IF TWO ASSOCIATED CONTROLS ARE OPERATED SIMULTANEOUSLY, ACTUATION WILL OCCUR IN ALL DIVISIONS.
2. COMPONENTS ARE ALL INDIVIDUALLY SEALED IN (LATCHED), SO THAT LOSS OF THE ACTUATION SIGNAL WILL NOT CAUSE THESE COMPONENTS TO RETURN TO THE CONDITION HELD PRIOR TO THE ADVENT OF THE ACTUATION SIGNAL.
3. THE MANUAL RESET CONSISTS OF SEPARATE MOMENTARY CONTROLS. OPERATING EACH CONTROL WILL RESET A SEPARATE DIVISION.
4. CVS LETDOWN ISOLATION ALSO OCCURS DURING CONTAINMENT ISOLATION. SEE PMS J1 113.

Figure 7.2-1 (Sheet 16 of 20)

Functional Diagram
In-Containment Refueling Water Storage Tank Actuations





NOTES:

1. THIS LOGIC IS REPEATED FOR EACH VALVE.
2. THE CONTROLS ARE LOCATED IN THE MAIN CONTROL ROOM AND DUPLICATED AT THE REMOTE SHUTDOWN WORK STATION, BUT ARE NOT FUNCTIONAL AT BOTH LOCATIONS SIMULTANEOUSLY.

Figure 7.2-1 (Sheet 17 of 20)

Functional Diagram
Passive Residual Heat Removal and
Core Makeup Tank Isolation Valve Interlocks

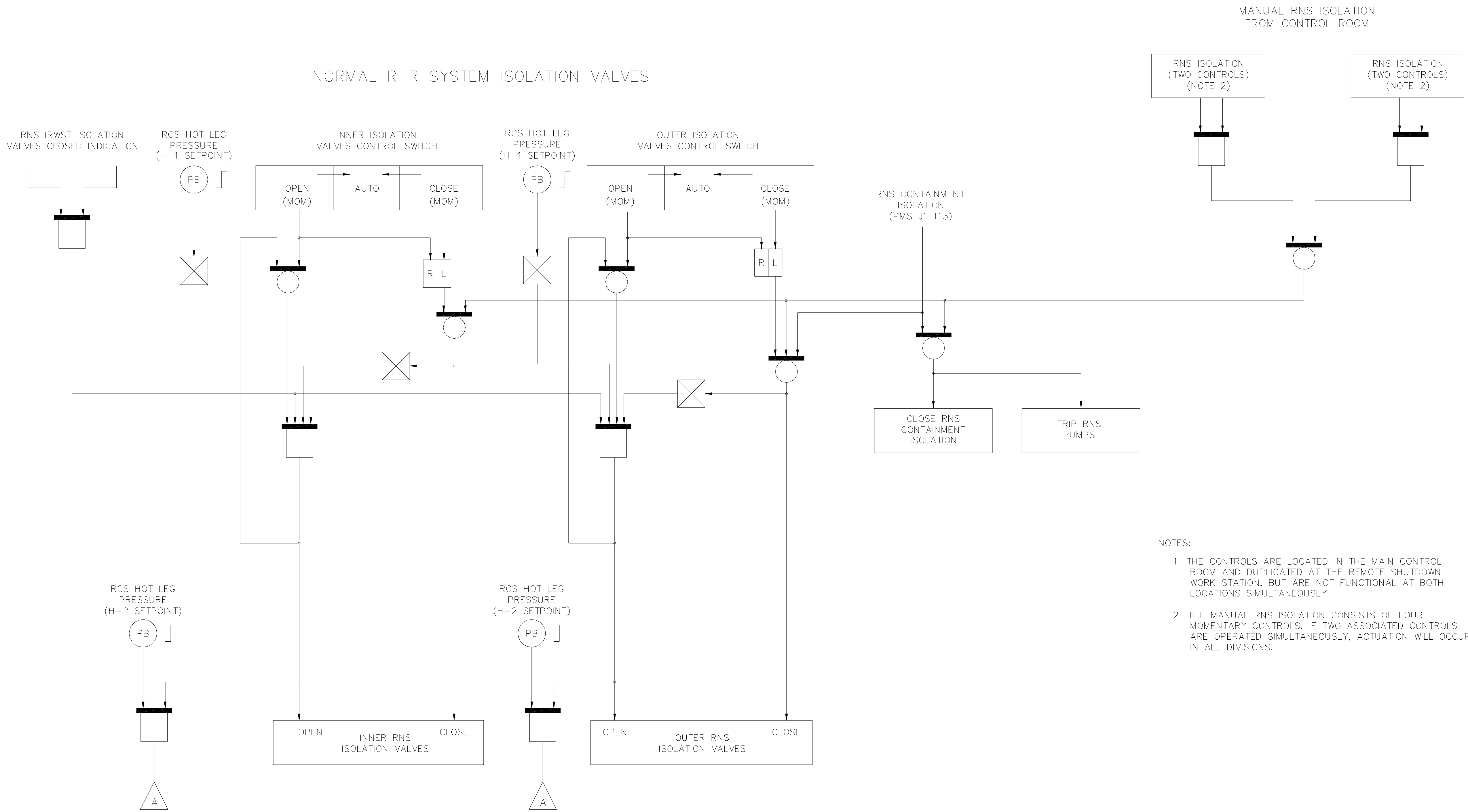


Figure 7.2-1 (Sheet 18 of 20)

Functional Diagram
Normal Residual Heat Removal System Isolation Valve Interlocks

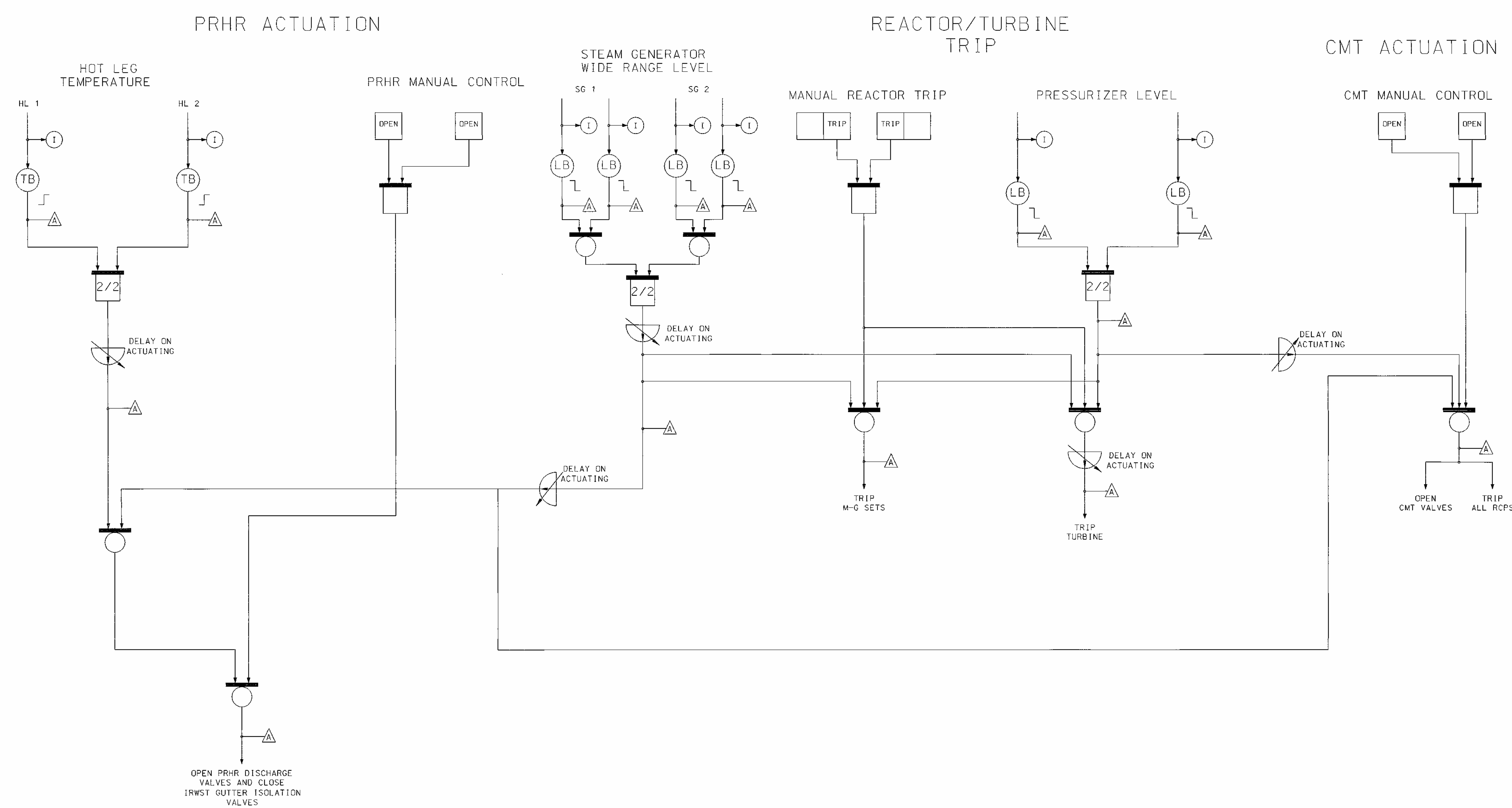


Figure 7.2-1 (Sheet 19 of 20)

Functional Diagram
Diverse Actuation System Logic Automatic Actuations

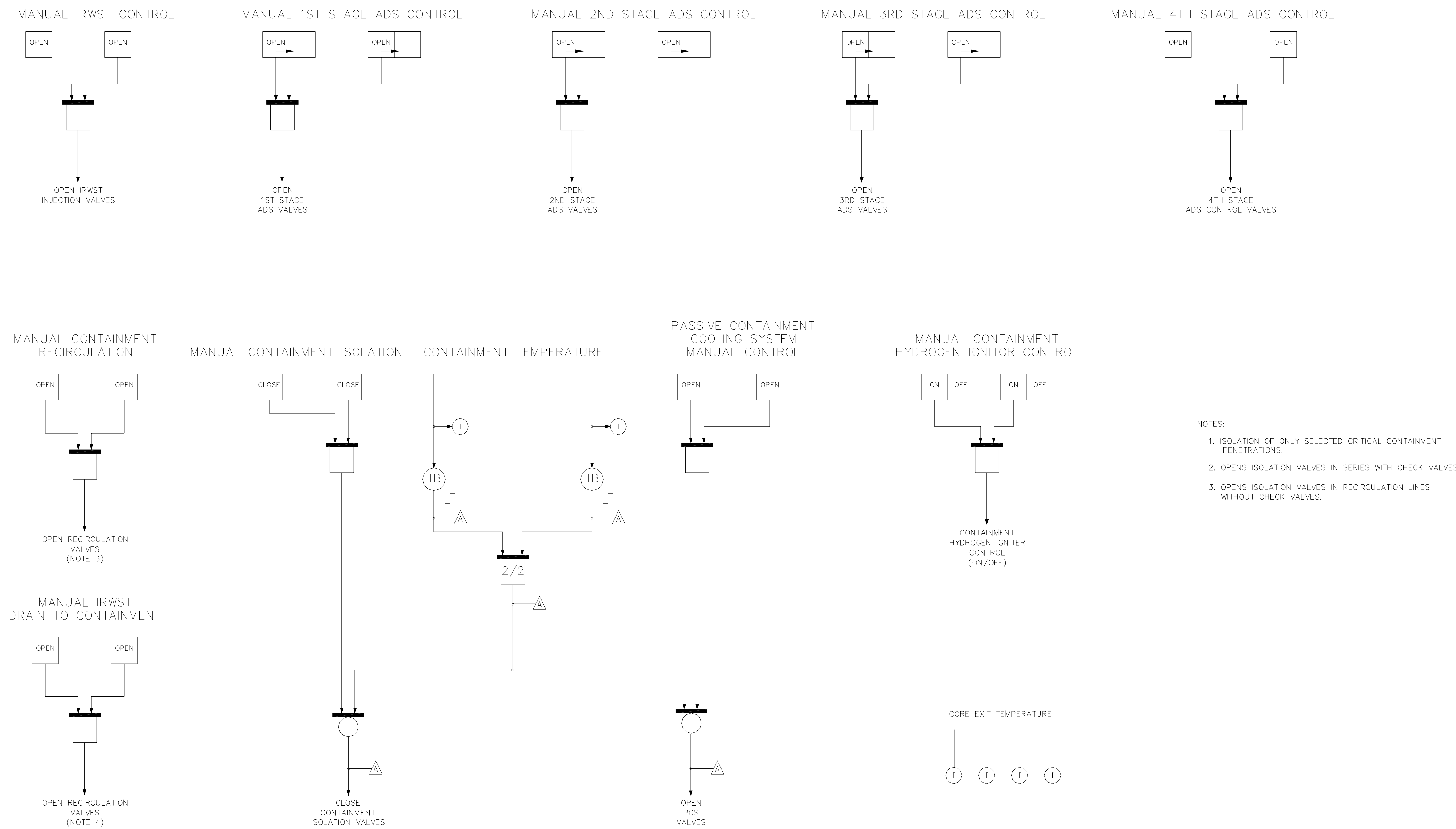


Figure 7.2-1 (Sheet 20 of 20)

Functional Diagram
Diverse Actuation System Logic, Manual Actuations

7.3 Engineered Safety Features

AP1000 provides instrumentation and controls to sense accident situations and initiate engineered safety features (ESF). The occurrence of a limiting fault, such as a loss of coolant accident or a secondary system break, requires a reactor trip plus actuation of one or more of the engineered safety features. This combination of events prevents or mitigates damage to the core and reactor coolant system components, and provides containment integrity.

7.3.1 Description

The protection and safety monitoring system is actuated when safety system setpoints are reached for selected plant parameters. The selected combination of process parameter setpoint violations is indicative of primary or secondary system boundary ruptures. Once the required logic combination is generated, the protection and safety monitoring system equipment sends the signals to actuate appropriate engineered safety features components. A block diagram of the protection and safety monitoring system is provided in Figure 7.1-2.

The following paragraphs summarize the major functional elements of the protection and safety monitoring system that are involved in generating an actuation signal to an engineered safety features component.

Four sensors normally monitor each variable used for an engineered safety feature actuation. (These sensors may monitor the same variable for a reactor trip function.) Analog measurements are converted to digital form by analog-to-digital converters within each of the four divisions of the protection and safety monitoring system. Following required signal conditioning or processing, the measurements are compared against the setpoints for the engineered safety feature to be generated. When the measurement exceeds the setpoint, the output of the comparison results in a channel partial trip condition. The partial trip information is transmitted to the ESF coincidence logic to form the signals that result in an engineered safety features actuation. The voting logic is performed twice within each division. Each voting logic element generates an actuation signal if the required coincidence of partial trips exists at its inputs.

The signals are combined within each division of ESF coincidence logic to generate a system-level signal. System-level manual actions are also processed by the logic in each division.

The system-level signals are then broken down to the individual actuation signals to actuate each component associated with a system-level engineered safety feature. For example, a single safeguards actuation signal must trip the reactor and the reactor coolant pumps, align core makeup tank and in-containment refueling water storage tank valves, and initiate containment isolation. The interposing logic accomplishes this function and also performs necessary interlocking so that components are properly aligned for safety. Component-level manual actions are also processed by this interposing logic. The power interface transforms the low level signals to voltages and currents commensurate with the actuation devices they operate. The actuation devices, in turn, control motive power to the final engineered safety feature component.

Subsection 7.3.1.2 provides a functional description of the signals and initiating logic for each of the engineered safety features. Figure 7.2-1 presents the functional diagrams for engineered safety features actuation.

Table 7.3-1 summarizes the signals and initiating logic for each of the engineered safety features initiated by the protection and safety monitoring system. Most of the functions provide protection against design basis events which are analyzed in Chapter 15. However, not all the functions listed in Table 7.3-1 are necessary to meet the assumptions used in performing the safety analysis. For example, the design provides features which provide automatic actuations which are not required for performing the safety analysis. In addition, some functions are provided to support assumptions used in the probabilistic risk assessment, but are not used to mitigate a design basis accident. Only those functions which meet the July 1993 NRC Final Policy Statement on Technical Specification Improvements criteria are included in the AP1000 DCD, Section 16.1, Technical Specifications. This accounts for any difference between functions listed in Table 7.3-1 and functions which are included in the Technical Specifications.

7.3.1.1 Safeguards Actuation (S) Signal

A safeguards actuation (S) signal is used in the initiation logic of many of the engineered safety features discussed in subsection 7.3.1.2. In addition, as described in Section 7.2, the safeguards actuation signal also initiates a reactor trip. The variables that are monitored and used to generate a safeguards actuation signal are typically those that provide indication of a significant plant transient that requires a response by several engineered safety features.

The safeguards actuation signal is generated from any of the following initiating conditions:

1. Low pressurizer pressure
2. Low lead-lag compensated steam line pressure
3. Low reactor coolant inlet temperature
4. High-2 containment pressure
5. Manual initiation

Condition 1 results from the coincidence of pressurizer pressure below the Low setpoint in any two of the four divisions.

Condition 2 results from the coincidence of two of the four divisions of compensated steam line pressure below the Low setpoint in either of the two steam lines. The steam line pressure signal is lead-lag compensated to improve system response.

Condition 3 results from the coincidence of two of the four divisions of reactor coolant system cold leg temperature below the Low setpoint in any loop.

Condition 4 results from the coincidence of two of the four divisions of containment pressure above the High-2 setpoint.

Condition 5 consists of two momentary controls. Manual actuation of either of the two controls will trip the reactor and generate a safeguards actuation signal.

To permit startup and cooldown, the safeguards actuation signals generated from low pressurizer pressure, low steam line pressure, or low reactor coolant inlet temperature can be manually blocked when pressurizer pressure is below the P-11 setpoint. The signal is automatically unblocked when the pressurizer pressure is above the P-11 setpoint.

Separate momentary controls are provided, each of which will manually reset the safeguards actuation signal in a single division. Manual reset of a safeguards actuation signal in coincidence with reactor trip (P-4) blocks the safeguards actuation signal. Absence of P-4 automatically resets the blocking function. The safeguards actuation signal is manually reset based on a preset delay following initiation. Resetting the signal does not reposition any safeguards actuated equipment, since individual components are required to latch in and seal on the safeguards actuation signal.

The logic relating to the development of the safeguards actuation signal is illustrated in Figure 7.2-1, sheets 9 and 11.

7.3.1.2 Engineered Safety Feature Descriptions

The following subsections provide a functional description of the signals and initiating logic for each engineered safety feature. Table 7.3-1 lists the signals and summarizes the coincidence logic used to generate the safeguards actuation signal or initiate each engineered safety feature. Table 7.3-2 describes the permissives and interlocks relating to the engineered safety features. Table 7.3-3 lists the system-level manual input to the engineered safety features.

7.3.1.2.1 Containment Isolation

A signal to actuate containment isolation is generated from any of the following conditions:

1. Automatic or manual safeguards actuation signal (subsection 7.3.1.1)
2. Manual initiation
3. Manual actuation of passive containment cooling (subsection 7.3.1.2.12)

Conditions 1 and 3 are discussed in other subsections as noted.

Condition 2 consists of the manual actuation of either of two momentary controls in the main control room. Either control actuates all divisions and closes the nonessential fluid system paths from the containment.

Manual reset is provided to block the automatic actuation signal for containment isolation. Separate momentary controls are provided for resetting each division.

No other interlocks or permissive signals apply directly to the containment isolation function. Automatic actuation originates from a safeguards actuation (S) signal that does contain interlock and permissive inputs.

The functional logic that actuates containment isolation is illustrated in Figure 7.2-1, sheets 11 and 13.

7.3.1.2.2 In-Containment Refueling Water Storage Tank Injection

Signals to align the in-containment refueling water storage tank for injection are generated from the following conditions:

1. Actuation of the fourth stage of the automatic depressurization system (subsection 7.3.1.2.4)

2. Coincidence loop 1 and loop 2 hot leg levels below Low-2 setpoint for a duration exceeding an adjustable time delay

3. Manual initiation

Each of the above conditions opens the in-containment refueling water storage tank injection valves, thereby providing a flow path to the reactor coolant system.

In addition to initiating in-containment refueling water storage tank injection, condition 2 also initiates the opening sequence of the fourth stage of the automatic depressurization system. This is discussed in subsection 7.3.1.2.4.

Condition 3 consists of two sets of two momentary controls. Manual actuation of both controls of either of the two control sets generates signals that open the in-containment refueling water storage tank injection valves. A two-control simultaneous actuation prevents inadvertent actuation.

In-containment refueling water storage tank injection on Low-2 hot leg level is automatically blocked when the pressurizer water level is above the P-12 setpoint. This reduces the probability of a spurious injection. This block is removed when the core makeup tank actuation on low pressurizer level function is manually blocked to allow mid-loop operation. As described in subsection 7.3.1.2.3, this core makeup tank actuation function can be manually blocked when the pressurizer water level is below the P-12 setpoint.

The functional logic relating to in-containment refueling water storage tank injection is illustrated in Figure 7.2-1, sheets 12 and 16.

7.3.1.2.3 Core Makeup Tank Injection

Signals to align the core makeup tanks for injection are generated from the following conditions:

1. Automatic or manual safeguards actuation (subsection 7.3.1.1)

2. Automatic or manual actuation of the first stage of the automatic depressurization system (subsection 7.3.1.2.4)

3. Low-2 pressurizer level

4. Low wide range steam generator level coincident with High hot leg temperature

5. Manual initiation

6. Pressurizer water level increasing above the P-12 interlock

Conditions 1 through 5 initiates a block of the pressurizer heaters; trip the reactor and reactor coolant pumps; initiate alignment of the core makeup tank isolation valves for passive injection to the reactor coolant system; and provide a confirmatory open signal to the cold leg balance line isolation valves. The balance line isolation valves are normally open but can be closed by the operator. The confirmatory open signal automatically overrides any bypass features that are provided to allow the cold leg balance line isolation valves to be closed for short periods of time. Condition 6 initiates a confirmatory open signal to the cold leg balance line isolation valves. The motive force for core makeup tank injection is provided by density differences between the fluids in the cold leg balance line and the core makeup tank water.

Condition 3 results from the coincidence of pressurizer level below the Low-2 setpoint in any two of the four divisions. This function can be manually blocked when the pressurizer water level is below the P-12 setpoint. This function is automatically unblocked when the pressurizer water level is above the P-12 setpoint.

Condition 4 is derived from a coincidence of:

- Both steam generator 1 and steam generator 2 wide range level below the Low setpoint (derived from two of the four wide range level measurement divisions for each steam generator), and

- Two of the four divisions of hot leg temperature above the High (T_{hot}) setpoint

Condition 5 consists of two momentary controls. Manual actuation of either of the two controls will align the core makeup tanks for injection.

The functional logic relating to core makeup tank injection is illustrated in Figure 7.2-1, sheets 7, 12 and 15.

7.3.1.2.4 Automatic Depressurization System Actuation

A signal to actuate the first stage of the automatic depressurization system is generated from any of the following conditions:

1. Core makeup tank injection alignment signal (subsection 7.3.1.2.3) coincident with core makeup tank level less than the Low-1 setpoint in either core makeup tank in two of the four divisions

2. Extended loss of ac power sources

3. Manual initiation

Any actuation of the first stage of the automatic depressurization system also trips the reactor and reactor coolant pumps, align the core makeup tanks for injection, and actuates the passive residual heat removal heat exchanger.

The automatic depressurization system is arranged to sequentially open four parallel stages of valves. Each of the first three stages consists of two parallel paths with each path containing an isolation valve and a depressurization valve. The first three stages are connected to the pressurizer and discharge into the in-containment refueling water storage tank. The fourth stage paths are connected to the hot legs of the reactor coolant system and discharge to containment.

The first stage isolation valves open on any actuation of the first stage of the automatic depressurization system. The first stage depressurization valves are opened following a preset time delay after the opening of the isolation valves. No interlocks or permissive signals apply directly to the first stage depressurization. However, some safeguards actuation signals, from which the core makeup tank injection actuation signal is derived, do contain interlock and permissive inputs.

The second stage isolation valves are opened following a preset time delay after the first stage depressurization valves open. The second stage depressurization valves are opened following a preset time delay after the second stage isolation valves are opened, similar to stage one. Actuation of the second stage depressurization valves is interlocked with the first stage depressurization actuation signal so that the second stage is not actuated until after the first stage actuation signal has been generated.

Similar to the second stage, the third stage isolation valves are opened following a preset time delay after the opening of the second stage depressurization valves. The third stage depressurization valves are opened following a preset time delay after the third stage isolation valves are opened. Actuation of the third stage depressurization valves is interlocked with the second stage depressurization actuation signal such that the third stage is not actuated until after the second stage actuation signal has been generated.

The fourth stage of the automatic depressurization system consists of four parallel paths. Each of these paths consists of a normally open isolation valve and a depressurization valve. The four paths are divided into two redundant groups with two paths in each group. Within each group, one path is designated to be substage A and the second path is designated to be substage B.

The fourth stage is actuated upon the coincidence of a Low-2 core makeup tank level and Low reactor coolant system pressure following a preset time delay after the third stage depressurization valves are opened. The Low-2 core makeup tank level input is based on the core makeup tank level being less than the Low-2 setpoint in two of the four divisions in either core makeup tank. Upon a fourth stage actuation signal, a confirmatory open signal is immediately provided to the substage-A isolation valves. The substage-A depressurization valves are opened following a preset time delay after the substage-A isolation valve confirmatory open signal. The sequence is continued with substage-B. A confirmatory open signal is provided to the substage-B isolation valves following a preset time delay after the substage-A depressurization valve has been opened. The signal to open the substage-B

depressurization valve is provided following a preset time delay after the substage-B isolation valves confirmatory open signal. The net effect is to provide a controlled depressurization of the reactor coolant system. In addition to initiating this controlled depressurization sequence, the fourth stage actuation signal also provides a signal that aligns the in-containment refueling water storage tank for injection, as discussed in subsection 7.3.1.2.2.

A signal to initiate the opening sequence of the fourth stage is also generated upon the occurrence of coincidence loop 1 and loop 2 hot leg levels below the Low-2 setpoint for a duration exceeding an adjustable time delay. This signal also initiates in-containment refueling water storage tank injection. As discussed in subsection 7.3.1.2.2, this signal is automatically blocked when the pressurizer water level is above the P-12 setpoint. This reduces the probability of a spurious signal. The block is removed when the core makeup tanks actuation on low pressurizer level function is manually blocked to allow mid-loop operation.

The fourth stage can also be manually initiated. In this case the manual initiation signal is interlocked to prevent actuation until either the reactor coolant system pressure has decreased below a preset setpoint, or until the signals which control the opening sequence of the first, second, and third stage valves have been generated. As discussed above, the signals to the first, second, and third stage valves are generated based on preset time delays.

The core makeup tank injection alignment signal, which is part of condition 1, is latched-in upon its occurrence. A deliberate operator action is required to reset this latch. This feature is provided so that an automatic depressurization system actuation signal is not cleared by the reset of the safeguards actuation signal as discussed in subsection 7.3.1.1.

Condition 2 results from the loss of all ac power for a period of time that approaches the 24-hour Class 1E dc battery capability to activate the automatic depressurization system valves. The timed output holds upon restoration of ac power and is manually reset after the batteries are recharged. The loss of all ac power is detected by undervoltage sensors that are connected to the input of each of the four Class 1E battery chargers. Two sensors are connected to each of the four battery charger inputs. The loss of ac power signal is based on the detection of an undervoltage condition by either of the two sensors connected to two of the four battery chargers.

Condition 3 is achieved via either of two sets of two momentary controls. If both controls of either set are operated simultaneously, actuation of the automatic depressurization system occurs. A two-control simultaneous actuation prevents inadvertent actuation.

The functional logic relating to automatic depressurization operation is illustrated in Figure 7.2-1, sheet 15.

7.3.1.2.5 Reactor Coolant Pump Trip

A signal to trip reactor coolant pumps is generated from any one of the following conditions:

1. Automatic or manual safeguards actuation signal (subsection 7.3.1.1)

2. Automatic or manual actuation of the first stage of the automatic depressurization system (subsection 7.3.1.2.4)

3. Low-2 pressurizer level

4. Low wide range steam generator level coincident with High hot leg temperature

5. Manual initiation of core makeup tank injection (subsection 7.3.1.2.3)

6. High reactor coolant pump bearing water temperature (trips only affected reactor coolant pump)

Once a signal to trip a reactor coolant pump is generated, the actual tripping of the pump is delayed by a preset time delay. While conditions 1 through 5 trip all four reactor coolant pumps, condition 6 trips only the reactor coolant pump with the high bearing water temperature condition.

Condition 3 results from the coincidence of pressurizer level below the Low-2 setpoint in any two of the four divisions. This function can be manually blocked when the pressurizer water level is below the P-12 setpoint. This function is automatically unblocked when the pressurizer water level is above the P-12 setpoint.

Condition 4 is derived from a coincidence of:

- Both steam generator 1 and steam generator 2 wide range level below the Low setpoint (derived from two of the four wide range level measurement divisions for each steam generator), and

- Two of the four divisions of hot leg temperature above the High (T_{hot}) setpoint

Condition 6 is derived from a coincidence of two of the four divisions of high reactor coolant pump bearing water temperature for a single reactor coolant pump. Each reactor coolant pump is tripped independently if Condition 6 is met for its own bearing water temperature. This function is included for equipment protection. The high temperature setpoint and dynamic compensation are the same as used in the high reactor coolant pump bearing water temperature reactor trip (subsection 7.2.1.1.3) but with the inclusion of preset time delay.

The functional logic relating to the tripping of the reactor coolant pumps is illustrated in Figure 7.2-1, sheets 5, 7, 12, and 15.

7.3.1.2.6 Main Feedwater Isolation

Signals to isolate the main feedwater supply to the steam generators are generated from any of the following conditions:

1. Automatic or manual safeguards actuation (subsection 7.3.1.1)
2. Manual initiation
3. High-2 steam generator narrow range water level

4. Low-1 reactor coolant system average temperature coincident with P-4 permissive
5. Low-2 reactor coolant system average temperature coincident with P-4 permissive

Conditions 1, 2, and 3 isolate the main feedwater supply by tripping the main feedwater pumps and closing the main feedwater control, isolation and crossover valves. These conditions also initiate a turbine trip.

Condition 2 consists of two momentary controls. Manual actuation of either of the two controls will trip the turbine and isolate the main feedwater supply. This action also initiates isolation of startup feedwater (subsection 7.3.1.2.13).

Condition 3 is derived from a coincidence of two of the four divisions of narrow range steam generator water level above the High-2 setpoint for either steam generator. In addition to tripping the turbine and isolating the main feedwater supply, condition 3 also initiates a reactor trip, isolates the startup feedwater supply (subsection 7.3.1.2.13), and isolates the chemical volume control system.

Condition 4 results from a coincidence of two of the four divisions of reactor loop average temperature (T_{avg}) below the Low-1 setpoint coincident with the P-4 permissive (reactor trip). This condition results in the closure of the main feedwater control valves. The feedwater isolation resulting from this condition may be manually blocked when the pressurizer pressure is below the P-11 setpoint. The block is automatically removed when the pressurizer pressure is above the P-11 setpoint.

Condition 5 results from a coincidence of two of the four divisions of reactor loop average temperature (T_{avg}) below the Low-2 setpoint coincident with the P-4 permissive (reactor trip). This condition results in the tripping of the main feedwater pumps and closure of the main feedwater isolation and crossover valves. The feedwater isolation resulting from this condition may be manually blocked when the pressurizer pressure is below the P-11 setpoint. The block is automatically removed when the pressurizer pressure is above the P-11 setpoint.

Condition 5 also blocks the steam dump valves and becomes an interlock to the steam dump interlock selector switch. This is discussed in subsection 7.3.1.2.16.

The functional logic relating to the isolation of the main feedwater is illustrated in Figure 7.2-1, sheet 10.

7.3.1.2.7 Passive Residual Heat Removal Heat Exchanger Alignment

A signal to align the passive heat removal heat exchanger to passively remove core heat is generated from any of the following conditions:

1. Core makeup tank injection alignment signal (subsection 7.3.1.2.3)
2. First stage automatic depressurization system actuation (subsection 7.3.1.2.4)
3. Low wide range steam generator level
4. Low narrow range steam generator level coincident with Low startup feedwater flow
5. High-3 pressurizer water level
6. Manual initiation

Each of these conditions opens the passive residual heat removal discharge isolation valves, closes the in-containment refueling water storage tank gutter isolation valves, and provides a confirmatory open signal to the inlet isolation valve. The inlet isolation valve is normally open but can be closed by the operator. These conditions override any closure signal to this valve and also close the blowdown isolation valves in both steam generators.

Condition 3 results from the coincidence of two of the four divisions of wide range steam generator level below the Low setpoint in either of the two steam generators.

Condition 4 results from the coincidence of two of the four divisions of narrow range steam generator level below the Low setpoint, after a preset time delay, coincident with a Low startup feedwater flow in a particular steam generator. This function is provided for each of the two steam generators. The low narrow range steam generator level also isolates blowdown in the affected steam generator.

Condition 5 results from the coincidence of pressurizer level above the High-3 setpoint in any two of four divisions. This function can be manually blocked when the reactor coolant system pressure is below the P-19 permissive setpoint to permit pressurizer water solid conditions with the plant cold. This function is automatically unblocked when reactor coolant system pressure is above the P-19 setpoint. In addition to actuating the passive residual heat removal heat exchanger, condition 5 initiates a block of the pressurizer heaters.

Condition 6 consists of two momentary controls. Manual actuation of either of the two controls will align the passive residual heat removal heat exchanger initiating heat removal by this path.

The functional logic relating to alignment of the passive residual heat removal heat exchanger is illustrated in Figure 7.2-1, sheet 8.

7.3.1.2.8 Turbine Trip

A signal to initiate turbine trip is generated from any of the following conditions:

1. Reactor trip (Table 7.3-2, interlock P-4)
2. High-2 steam generator narrow-range water level
3. Manual feedwater isolation (subsection 7.3.1.2.6)

Each of these conditions initiates a turbine trip to prevent or terminate an excessive cooldown of the reactor or minimizes the potential for equipment damage caused by loss of steam supply to the turbine.

Condition 2 results from a coincidence of two of the four divisions of narrow range steam generator water level above the High-2 setpoint for either steam generator.

The functional logic relating to the tripping of the turbine is illustrated in Figure 7.2-1, sheet 14.

7.3.1.2.9 Containment Recirculation

Signals to align the containment recirculation isolation valves are generated from the following conditions:

1. Low-3 in-containment refueling water storage tank water level in coincidence with fourth stage automatic depressurization system actuation (subsection 7.3.1.2.4)

2. Manual initiation

3. Extended loss of ac power sources

There are four parallel containment recirculation paths provided to permit the recirculation of the water provided by the in-containment refueling water storage tank. Two of these paths are provided with two isolation valves in series while the remaining two paths are provided with a single isolation valve in series with a check valve.

Conditions 1 and 2 result in the opening of all isolation valves in all four parallel paths. Condition 3 results in the opening of the two isolation valves that are in series with the check valves.

Condition 1 results from the coincidence of two of the four divisions of in-containment refueling water storage tank water level below the Low-3 setpoint, coincident with an automatic fourth stage automatic depressurization system signal.

Condition 2 consists of two sets of two momentary controls. Manual actuation of both controls of either of the two control sets initiates recirculation in all four parallel paths. A two-control simultaneous actuation prevents inadvertent actuation.

Condition 3 results from the loss of all ac power for a period of time that approaches the 24-hour Class 1E dc battery capability to activate the in-containment refueling water storage tank containment recirculation isolation valves. The timed output holds on restoration of ac power and is manually reset after the batteries are recharged. The loss of all ac power is detected by undervoltage sensors that are connected to the input of each of the four Class 1E battery chargers. Two sensors are connected to each of the four battery charger inputs. The loss of ac power signal is based on the detection of an undervoltage condition by either of the two sensors connected to two of the four battery chargers.

The functional logic relating to activation of the containment recirculation isolation valves is illustrated in Figure 7.2-1, sheets 15 and 16.

7.3.1.2.10 Steam Line Isolation

A signal to isolate the steam line is generated from any one of the following conditions:

1. Manual initiation
2. High-2 containment pressure
3. Low lead-lag compensated steam line pressure

4. High steam line pressure negative rate
5. Low reactor coolant inlet temperature

The steam line isolation signal closes the main steam line isolation valves and the stop and bypass valves. In addition to manual system-level steam line isolation, steam line isolation valves can be closed individually.

Condition 1 consists of two momentary controls. Manual actuation of either of the two controls initiates steam line isolation for both steam generators. In addition, separate controls are provided for steam line isolation of each individual steam generator.

Condition 2 results from the coincidence of two of the four divisions of containment pressure above the High-2 setpoint.

Condition 3 results from the coincidence of two of the four divisions of compensated steam line pressure below the Low setpoint. The steam line pressure signal is lead-lag compensated to improve system response. If the pressure is below this setpoint, in either steam line, both main steam lines are isolated.

Condition 4 results from the coincidence in either steam line of two of the four divisions of rate-lag compensated steam line pressure exceeding the High negative rate setpoint.

Condition 5 results from the coincidence of reactor coolant system cold leg temperature below the Low T_{cold} setpoint in any loop.

Steam line isolation for conditions 3 and 5 may be manually blocked when pressurizer pressure is below the P-11 setpoint and is automatically unblocked when pressurizer pressure is above P-11. Steam line isolation on condition 4 is automatically blocked when pressurizer pressure is above P-11 and is automatically unblocked on the manual blocking of the steam line isolation for conditions 3 and 5. Under all plant conditions, steam line isolation is automatically provided on either Condition 3 or 5, or Condition 4.

The functional logic relating to main steam isolation is illustrated in Figure 7.2-1, sheet 9.

7.3.1.2.11 Steam Generator Blowdown System Isolation

Signals to close the isolation valves of the steam generator blowdown system in both steam generators are generated from the following conditions:

1. Passive residual heat removal heat exchanger alignment signal (subsection 7.3.1.2.7)
2. Low narrow range steam generator level

Condition 2 results from the coincidence of two of the four divisions of narrow range steam generator level below the Low setpoint. This condition only closes the blowdown system isolation valves of the affected steam generator.

The functional logic relating to steam generator blowdown isolation is illustrated in Figure 7.2-1, sheets 7 and 8.

7.3.1.2.12 Passive Containment Cooling Actuation

A signal to actuate the passive containment cooling system is generated from either of the following conditions:

1. Manual initiation
2. High-2 containment pressure

The passive containment cooling actuation signal opens valves that initiate gravity flow of cooling water from the passive containment cooling system water storage tank to the top of the containment shell. The evaporation of the water on the containment shell provides the passive cooling.

Condition 1 consists of two momentary controls. Manual actuation of either of the two controls results in manual actuation of the passive containment cooling system. This action also initiates containment isolation (subsection 7.3.1.2.1) and isolation of the containment air filtration system (subsection 7.3.1.2.19).

Condition 2 results from a coincidence of two of the four divisions of containment pressure above the High-2 setpoint. Manual reset is provided to block this actuation signal for passive containment cooling. Separate momentary controls are provided for resetting each division.

The functional logic relating to actuation of the passive containment cooling system is illustrated in Figure 7.2-1, sheet 13.

7.3.1.2.13 Startup Feedwater Isolation

Signals to isolate the startup feedwater supply to the steam generators are generated from either of the following conditions:

1. Low reactor coolant inlet temperature
2. High-2 steam generator narrow range water level
3. Manual actuation of main feedwater isolation (subsection 7.3.1.2.6)

Any of these conditions isolates the startup feedwater supply by tripping the startup feedwater pumps and closing the startup feedwater isolation and control valves.

Condition 1 results from the coincidence of reactor coolant system cold leg temperature below the Low T_{cold} setpoint in any loop. Startup feedwater isolation on this condition may be manually blocked when the pressurizer pressure is below the P-11 setpoint. This function is automatically unblocked when the pressurizer pressure is above the P-11 setpoint.

Condition 2 results from a coincidence of two of the four divisions of narrow range steam generator water level above the High-2 setpoint for either steam generator.

Condition 3 is discussed in other subsections as noted.

The functional logic relating to the isolation of the startup feedwater is illustrated in Figure 7.2-1, sheets 9 and 10.

7.3.1.2.14 Boron Dilution Block

Signals to block boron dilution are generated from any of the following conditions:

1. Excessive increasing rate of source range nuclear power
2. Loss of ac power sources
3. Reactor trip (Table 7.3-2, interlock P-4)

The block of boron dilution is accomplished by closing the chemical and volume control system suction valves to demineralized water storage tanks, and aligning the boric acid tank to the reactor coolant system makeup pumps.

Condition 1 is an average of the source range count rate, sampled at least N times over the most recent time period T_1, compared to a similar average taken at time period T_2 earlier. If the ratio of the current average count rate to the earlier average count rate is greater than a preset value, a partial trip is generated in the division. On a coincidence of excessively increasing source range neutron flux in two of the four divisions, boron dilution is blocked. This source range flux doubling signal may be manually blocked to permit plant startup and normal power operation. It is automatically reinstated when reactor power is decreased below the P-6 power level during shutdown.

Condition 2 results from the loss of ac power. A short, preset time delay is provided to prevent actuation upon momentary power fluctuations; however, actuation occurs before ac power is restored by the onsite diesel generators. The loss of all ac power is detected by undervoltage sensors that are connected to the input of each of the four Class 1E battery chargers. Two sensors are connected to each of the four battery charger inputs. The loss of ac power signal is based on the detection of an undervoltage condition by each of the two sensors connected to two of the four battery chargers. The two-out-of-four logic is based on an undervoltage to the battery chargers for divisions A or C coincident with an undervoltage to the battery chargers for divisions B or D.

The functional logic relating to the boron dilution block is illustrated in Figure 7.2-1, sheets 3 and 15.

7.3.1.2.15 Chemical and Volume Control System Isolation

A signal to close the isolation valves of the chemical and volume control system is generated from any of the following conditions:

1. High-2 pressurizer level

2. High-2 steam generator narrow range water level

3. Automatic or manual safeguards actuation signal (subsection 7.3.1.1) coincident with High-1 pressurizer level

4. High-2 containment radioactivity

5. Manual initiation

Condition 1 results from the coincidence of pressurizer level above the High-2 setpoint in any two of the four divisions. This function can be manually blocked when the reactor coolant system pressure is below the P-19 permissive setpoint to permit pressurizer water solid conditions with the plant cold and to permit pressurizer level makeup during plant cooldowns. This function is automatically unblocked when reactor coolant system pressure is above the P-19 setpoint.

Condition 2 results from a coincidence of two of the four divisions of narrow range steam generator water level above the High-2 setpoint for either steam generator.

Condition 3 results from the coincidence of two of the four divisions of pressurizer level above the High-1 setpoint, coincident with an automatic or manual safeguards actuation.

Condition 4 results from the coincidence of containment radioactivity above the High-2 setpoint in any two of the four divisions.

Condition 5 consists of two momentary controls. This action also initiates auxiliary spray and letdown purification line isolation (subsection 7.3.1.2.18).

The functional logic relating to chemical and volume control system isolation is illustrated in Figure 7.2-1, sheets 6 and 11.

7.3.1.2.16 Steam Dump Block

Signals to block steam dump (turbine bypass) are generated from either of the following conditions:

1. Low-2 reactor coolant system average temperature coincident with P-4 permissive
2. Manual initiation

Condition 1 results from a coincidence of two of the four divisions of reactor loop average temperature (T_{avg}) below the Low-2 setpoint coincident with the P-4 permissive (reactor trip). This blocks the opening of the steam dump valves. This signal also becomes an input to the steam dump interlock selector switch for unblocking the steam dump valves used for plant cooldown. This function may be manually blocked when the pressurizer pressure is below the P-11 setpoint. The block is automatically removed when the pressurizer pressure is above the P-11 setpoint.

Condition 2 consists of two controls. Either one of these controls can be used to manually initiate a steam dump block.

The functional logic relating to the steam dump block is illustrated in Figure 7.2-1, sheet 10.

7.3.1.2.17 Control Room Isolation and Air Supply Initiation

Signals to initiate isolation of the main control room, to initiate the air supply, and to open the control room pressure relief isolation valves are generated from either of the following conditions:

1. High-2 control room air supply radioactivity level
2. Loss of ac power sources
3. Manual initiation

Condition 1 is the occurrence one of two control room air supply radioactivity monitors detecting a radioactivity level above the High-2 setpoint.

Condition 2 results from the loss of all ac power sources. A preset time delay is provided to permit the restoration of ac power from the offsite sources or from the onsite diesel generators before initiation. The loss of all ac power is detected by undervoltage sensors that are connected to the input of each of the four Class 1E battery chargers. Two sensors are connected to each of the four battery charger inputs. The loss of ac power signal is based on the detection of an undervoltage condition by each of the two sensors connected to two of the four battery chargers. The two-out-of-four logic is based on an undervoltage to the battery chargers for divisions A or C coincident with an undervoltage to the battery chargers for divisions B or D.

Condition 3 consists of two momentary controls. Manual actuation of either of the two controls will result in control room isolation and air supply initiation.

The functional logic relating to control room isolation and air supply initiation is illustrated in Figure 7.2-1, sheet 13.

7.3.1.2.18 Auxiliary Spray and Letdown Purification Line Isolation

A signal to isolate the auxiliary spray and letdown purification lines is generated upon the coincidence of pressurizer level below the Low-1 setpoint in any two of four divisions. This helps to maintain reactor coolant system inventory. This function can be manually blocked when the pressurizer water level is below the P-12 setpoint. This function is automatically unblocked when the pressurizer water level is above the P-12 setpoint. The functional logic relating to this is illustrated in Figure 7.2-1, sheet 12.

The auxiliary spray and letdown purification line isolation signal is also generated upon manual actuation of chemical and volume control system isolation (subsection 7.3.1.2.15).

7.3.1.2.19 Containment Air Filtration System Isolation

A signal to isolate the containment air filtration system is generated from any of the following conditions:

1. Automatic or manual safeguards actuation signal (subsection 7.3.1.1)
2. Manual actuation of containment isolation (subsection 7.3.1.2.1)

3. Manual actuation of passive containment cooling (subsection 7.3.1.2.12)
4. High-1 containment radioactivity

Conditions 1, 2, and 3 are discussed in other subsections as noted.

Condition 4 results from the coincidence of containment radioactivity above the High-1 setpoint in any two of the four divisions.

The manual reset which is provided to block the automatic actuation signal for containment isolation (subsection 7.3.1.2.1) also resets the containment air filtration system isolation signal generated as a result of condition 1.

No other interlocks or permissive signals apply directly to the containment air filtration system isolation function. Automatic actuation originates from a safeguards actuation (S) signal that does contain interlock and permissive inputs.

The functional logic relating to air filtration system isolation is illustrated in Figure 7.2-1, sheets 11 and 13.

7.3.1.2.20 Normal Residual Heat Removal System Isolation

Signals for isolating the normal residual heat removal system lines are generated from any of the following conditions:

1. Automatic or manual safeguards actuation signal (subsection 7.3.1.1)
2. High-2 containment radioactivity
3. Manual initiation

The isolation signal generated as a result of Condition 1 can be manually reset to block the isolation of the normal heat removal system lines. This is done to permit the normal residual heat removal system to operate after the occurrence of a safeguards actuation signal. Separate momentary controls are provided for resetting each division.

Condition 2 results from the coincidence of containment radioactivity above the High-2 setpoint in any two of the four divisions.

These actuation signals can be manually blocked when pressurizer pressure is below the P-11 permissive setpoint and are automatically unblocked when pressurizer pressure is above the P-11 setpoint.

Condition 3 consists of two sets of two momentary controls. Manual actuation of both controls of either of two control sets initiates closure of RNS isolation valves. A two-control simultaneous actuation prevents inadvertent actuation.

The functional logic relating to normal residual heat removal system isolation is illustrated in Figure 7.2-1, sheets 13 and 18.

7.3.1.2.21 Refueling Cavity Isolation

A signal for isolating the spent fuel pool cooling system lines is generated upon the coincidence of spent fuel pool level below the Low setpoint in two of three divisions. This helps to maintain the water inventory in the refueling cavity due to line leakage. The functional logic relating to this is illustrated in Figure 7.2-1, sheet 13.

7.3.1.2.22 Chemical and Volume Control System Letdown Isolation

A signal to isolate the letdown valves of the chemical and volume control system is generated upon the occurrence of a Low-1 hot leg level in either of the two hot leg loops. This helps to maintain reactor system inventory. The functional logic relating to this is illustrated in Figure 7.2-1, sheet 16. These letdown valves are also closed by the containment isolation function as described in subsection 7.3.1.2.1.

7.3.1.2.23 Pressurizer Heater Block

Signals for blocking the operation of the pressurizer heaters are generated from any of the following conditions:

1. Core makeup tank injection alignment signal (subsection 7.3.1.2.3)
2. High-3 pressurizer water level

Division A of the protection and safety monitoring system provides actuation signals to five load center circuit breakers which provide the power feed to five pressurizer heater electrical control centers. When these five power feed breakers are opened, all electrical power is removed from all pressurizer heaters. In addition, Division C of the protection and safety monitoring system provides a separate signal to the plant control system. This separate signal is used to command the plant control system to open the molded-case circuit breakers which provide a power feed to each individual pressurizer heater. This arrangement provides for complete blocking of the pressurizer heaters, even if a single component failure occurs.

The functional logic relating to the pressurizer heater block is illustrated in Figure 7.2-1, sheets 6 and 12.

7.3.1.2.24 Steam Generator Relief Isolation

A signal for closing the steam generator power operated relief valves and their block valves is generated from any of the following conditions:

1. Manual initiation
2. Low lead-lag compensated steam line pressure

Condition 2 results from the coincidence of two of the four divisions of compensated steam line pressure below the Low setpoint. The steam line pressure signal is lead-lag compensated to improve system response. The signal closes the steam generator power-operated relief valve and the associated block valve for the affected steam generator. Steam generator relief

isolation for condition 2 may be manually blocked when pressurizer pressure is below the P-11 setpoint and is automatically unblocked when pressurizer pressure is above P-11.

The functional logic relating to steam generator relief isolation is illustrated in Figure 7.2-1, sheet 9.

7.3.1.3 Blocks, Permissives, and Interlocks for Engineered Safety Features Actuation

The interlocks used for engineered safety features actuation are designated as "P-xx" permissives and are listed in Table 7.3-2.

7.3.1.4 Bypasses of Engineered Safety Features Actuation

The channels used in engineered safety features actuation that can be manually bypassed are indicated in Table 7.3-1. A description of this bypass capability is provided in subsection 7.1.2.9. The actuation logic is not bypassed for test. During tests, the actuation logic is fully tested by blocking the actuation logic output before it results in component actuation.

7.3.1.5 Design Basis for Engineered Safety Features Actuation

The following subsections provide the design bases information for engineered safety features actuation, including the information required by Section 4 of IEEE 603-1991. Engineered safety features are initiated by the protection and safety monitoring system. Those design bases relating to the equipment that initiates and accomplishes engineered safety features are given in WCAP-15776 (Reference 1). The design bases presented here concern the variables monitored for engineered safety features actuation and the minimum performance requirements in generating the actuation signals.

7.3.1.5.1 Design Basis: Generating Station Conditions Requiring Engineered Safety Features Actuation (Paragraph 4.1 of IEEE 603-1991)

The generating station conditions requiring protective action are identified in Table 15.0-6, which summarizes the engineered safety features as they relate to the Condition II, III, or IV events analyzed in Chapter 15.

7.3.1.5.2 Design Basis: Variables, Ranges, Accuracies, and Typical Response Times Used in Engineered Safety Features Actuation (Paragraphs 4.1, 4.2, and 4.4 of IEEE 603-1991)

The variables monitored for engineered safety features actuation are:

- Pressurizer pressure
- Pressurizer water level
- Reactor coolant temperature (T_{hot} and T_{cold}) in each loop
- Containment pressure
- Containment radioactivity level
- Steam line pressure in each steam line
- Water level in each steam generator (narrow and wide ranges)

- Source range neutron flux
- Core makeup tank level
- Reactor coolant level in each of the two hot legs
- Loss of ac power sources
- In-containment refueling water storage tank level
- Main control room supply air radioactivity level
- Reactor coolant pump bearing water temperature
- Startup feedwater flow
- Spent fuel pool level
- Reactor coolant pressure in each of the two hot legs

Subsections 7.3.1.1 and 7.3.1.2 discuss levels that result in engineered safety features actuation. The allowable values for the limiting conditions for operation and the trip setpoints for engineered safety features actuation are given in the technical specifications (Chapter 16).

Typical ranges, accuracies, and response times for the variables used in engineered safety features actuation are listed in Table 7.3-4. The time response is the maximum allowable time period for an actuation signal to reach the necessary components. It is based on following a step change in the applicable process parameter from 5 percent below to 5 percent above (or vice versa) the actuation setpoint with externally adjustable time delays set to OFF.

7.3.1.5.3 Design Basis: Spatially Dependent Variables Used for Engineered Safety Features Actuation (Paragraph 4.6 of IEEE 603-1991)

Spatially dependent variables are discussed in subsection 7.2.1.2.3.

7.3.1.5.4 Design Basis: Limits for Engineered Safety Features Parameters in Various Reactor Operating Modes (Paragraph 4.3 of IEEE 603-1991)

During startup or shutdown, various engineered safety features actuation can be manually blocked. These functions are listed in Table 7.3-1.

During testing or maintenance of the protection and safety monitoring system, certain channels used for engineered safety features may be bypassed. Although no setpoints are changed for bypassing, the logic is automatically adjusted, as described in subsection 7.3.1.4. The safeguards channels that can be bypassed in the protection and safety monitoring system are listed in Table 7.3-1.

7.3.1.5.5 Design Basis: Engineered Safety Features for Malfunctions, Accidents, Natural Phenomena, or Credible Events (Paragraph 4.7 and 4.8 of IEEE 603-1991)

The accidents that the various engineered safety features are designed to mitigate are detailed in Chapter 15. Table 15.0-6 contains a summary listing of the engineered safety features actuated for various Condition II, III, or IV events. It relies on provisions made to protect equipment against damage from natural phenomena and credible internal events. Consequently, there are no engineered safety features actuated by the protection and safety monitoring system to mitigate the consequences of events such as fires.

Functional diversity is used in determining the actuation signals for engineered safety features. For example, a safeguards actuation signal is generated from high containment pressure, low pressurizer pressure, and low compensated steam line pressure. Engineered safety features are not normally actuated by a single signal. The extent of this diversity is seen from the initiating signals presented in subsections 7.3.1.1 and 7.3.1.2. Table 7.3-1 also lists the engineered safety features signals and the conditions that result from their actuation.

Redundancy provides confidence that engineered safety features are actuated on demand, even when the protection and safety monitoring system is degraded by a single random failure. The single-failure criterion is met even when engineered safety features channels are bypassed.

7.3.1.6 System Drawings

Functional diagrams are provided in Figure 7.2-1.

7.3.2 Analysis for Engineered Safety Features Actuation

7.3.2.1 Failure Modes and Effects Analyses

The AP600 failure modes and effects analysis (Reference 1 of Section 7.2) examines failures of the protection and safety monitoring system. The AP1000 instrumentation and control systems are similar to the AP600. The Common Q failure modes and effects analysis is documented in Reference 3 of Section 7.2. Both of these analyses conclude that the protection system maintains safety functions during single point failures.

7.3.2.2 Conformance of Engineered Safety Features to the Requirements of IEEE 603-1991

The discussions presented in this subsection address only the functional aspects of actuating engineered safety features. Requirements addressing equipment in the protection and safety monitoring system are presented in WCAP-15776 (Reference 1).

7.3.2.2.1 Conformance to the General Functional Requirements for Engineered Safety Features Actuation (Section 5 of IEEE 603-1991)

The protection and safety monitoring system automatically generates an actuation signal for an engineered safety feature whenever a monitored condition reaches a preset value. The specific engineered safety features actuation functions are listed in Table 7.3-1 and are discussed in subsection 7.3.1.2.

Table 7.3-4 lists the ranges, accuracies, and response times of the parameters monitored. The engineered safety features, in conjunction with a reactor trip, protect against damage to the core and reactor coolant system components, as well as maintain containment integrity following a Condition II, III, or IV event. Table 15.0-6 summarizes the events that normally result in the initiation of engineered safety features. The setpoints that actuate engineered safety features are listed in the technical specifications (Chapter 16).

7.3.2.2.2 Conformance to the Single Failure Criterion for Engineered Safety Features Actuation (Paragraph 5.1 of IEEE 603-1991)

A single failure in the protection and safety monitoring system does not prevent an actuation of the engineered safety features when the monitored condition reaches the preset value that requires the initiation of an actuation signal. The single failure criterion is met even when one division of the ESF coincidence logic is being tested, as discussed in subsection 7.1.2.9, or when there is a bypass condition in connection with test or maintenance of the protection and safety monitoring system.

7.3.2.2.3 Conformance to the Requirements for Channel Independence of the Engineered Safety Features Actuation (Paragraph 5.6.1 of IEEE 603-1991)

A discussion of channel independence is presented in WCAP-15776 (Reference 1). The signals to initiate division A of the engineered safety features are electrically isolated from the signals to initiate the redundant divisions (B, C, and D). Divisions of the safeguards actuation system are electrically independent and redundant, as are the power supplies for the divisions up to and including the final actuated equipment.

7.3.2.2.4 Conformance to the Requirements Governing Control and Protection System Interaction of the Engineered Safety Features Actuation (Paragraphs 5.6.3.1, 5.6.3.3, and 6.3.1 of IEEE 603-1991)

Discussions on this subject are presented in WCAP-15776 (Reference 1).

7.3.2.2.5 Derivation of System Input for Engineered Safety Features Actuation (Paragraph 6.4 of IEEE 603-1991)

To the extent feasible and practical, the protection and safety monitoring system inputs used to actuate engineered safety features are derived from signals that are direct measures of the desired parameters. The parameters are listed in Table 7.3-4.

7.3.2.2.6 Capability for Sensor Checks and Equipment Test and Calibration of the Engineered Safety Features Actuation (Paragraphs 5.7 and 6.5 of IEEE 603-1991)

The discussion of system testability provided in Section 7.1 is applicable to the sensors, signal processing, and actuation logic that initiate engineered safety features actuation.

The testing program meets Regulatory Guide 1.22 as discussed in WCAP-15776 (Reference 1). The program is as follows:

- Prior to initial plant operations, engineered safety features tests are conducted.

- Subsequent to initial startup, engineered safety features tests are conducted during each regularly scheduled refueling outage.

- During operation of the reactor, the protection and safety monitoring system is tested as described in subsection 7.1.2.11. In addition, the engineered safety features final

actuators, whose operation is compatible with continued plant operation, are tested periodically at power.

- Continuity of the wiring is verified for devices that cannot be tested at power without damaging or upsetting the plant. Operability of the final actuated equipment is demonstrated at shutdown.

During reactor operation, the basis for acceptability of engineered safety features actuation is the successful completion of the overlapping tests performed on the protection and safety monitoring system. Process indications are used to verify operability of sensors.

7.3.2.2.7 Conformance to Requirements on Bypassing Engineered Safety Features Actuation Functions (Paragraph 5.8, 5.9, 6.6, and 6.7 of IEEE 603-1991)

Discussions on bypassing are provided in WCAP-15776 (Reference 1) and subsection 7.3.1.4.

7.3.2.2.8 Conformance to the Requirement for Completion of Engineered Safety Features Actuation Once Initiated (Paragraph 5.2 of IEEE 603-1991)

Once initiated, engineered safety features proceed to completion unless deliberate operator action is taken to terminate the function on a component-by-component basis.

Equipment actuated on a safeguards actuation signal cannot be returned to its previous position for a predetermined time period following initiation of the safeguards actuation signal. A block of the automatic safeguards signal is permitted at this time, if the reactor is tripped. This interlock is shown in Figure 7.2-1, sheet 11.

Resetting a system-level safeguards signal does not terminate any safeguards function. Rather, it permits the operator to individually reposition equipment. Equipment cannot be reset until the system-level signal is reset.

7.3.2.2.9 Conformance to the Requirement to Provide Manual Initiation at the System-Level for All Safeguards Actuation (Paragraph 6.2 of IEEE 603-1991)

Manual initiation at the system-level exists for the engineered safety features actuation. These system-level manual initiations are discussed in subsections 7.3.1.1 and 7.3.1.2.

As a minimum, two controls are provided for each system-level manual initiation so that the protective function can be manually initiated at the system-level, despite a single random failure in one control. In certain applications, such as automatic depressurization, two pairs of controls are provided. One pair must be actuated simultaneously. This reduces the likelihood of inadvertent actuation while providing a design that meets the single failure criterion.

7.3.3 Combined License Information

This section has no requirement for information to be provided in support of the Combined License application.

7.3.4 References

1. WCAP-15776, "Safety Criteria for the AP1000 Instrument and Control Systems," April 2002.

Table 7.3-1 (Sheet 1 of 8)

ENGINEERED SAFETY FEATURES ACTUATION SIGNALS

Actuation Signal	No. of Channels/ Switches	Actuation Logic	Permissives and Interlocks
1. Safeguards Actuation Signal (Figure 7.2-1, Sheets 9 and 11)			
a. Low pressurizer pressure	4	2/4-BYP[1]	Manual block permitted below P-11 Automatically unblocked above P-11
b. Low lead-lag compensated steam line pressure	4/steam line	2/4-BYP[1] in either steam line	Manual block permitted below P-11 Automatically unblocked above P-11
c. Low reactor coolant inlet temperature (Low T_{cold})	4/loop	2/4-BYP[1] either loop[6]	Manual block permitted below P-11 Automatically unblocked above P-11
d. High-2 containment pressure	4	2/4-BYP[1]	None
e. Manual safeguards initiation	2 switches	1/2 switches	Can be manually reset to block safeguards actuation upon P-4 Block automatically removed on absence of P-4
2. Containment Isolation (Figure 7.2-1 Sheets 11 and 13)			
a. Automatic or manual safeguards actuation signal	(See items 1a through 1e)		
b. Manual initiation	2 switches	1/2 switches	None
c. Manual initiation of passive containment cooling	(See item 10a)		
3. Automatic Depressurization System (Figure 7.2-1, Sheet 15) **(Initiate Stages 1, 2, and 3)**			
a. Core makeup tank injection coincident with	(See items 6a through 6e)		
Core makeup tank level less than Low-1 setpoint	4/tank	2/4-BYP[1] either tank[2]	None
b. Extended undervoltage to Class 1E battery chargers[(8)]	2/charger	1/2 per charger and 2/4 chargers	None
c. Stages 1, 2, and 3 manual initiation	4 switches	2/4 switches[3]	None

Table 7.3-1 (Sheet 2 of 8)

ENGINEERED SAFETY FEATURES ACTUATION SIGNALS

	Actuation Signal	No. of Channels/ Switches	Actuation Logic	Permissives and Interlocks
(Initiate Stage 4)				
d.	Stage 4 manual initiation coincident with one of the following two conditions:	4 switches	2/4 switches[3]	None
	Low reactor coolant system pressure or	4	2/4 BYP[1]	None
	Actuation of stages 1, 2, and 3	(See items 3a through 3c)		
e.	Core makeup tank level less than Low-2 setpoint coincident with	4/tank	2/4 BYP[1] either tank[2]	None
	Low reactor coolant system pressure and coincident with	4	2/4 BYP[1]	None
	3rd stage depressurization			
f.	Coincident loop 1 and loop 2 Low-2 hot leg level (after delay)	1 per loop	2/2	Manual unblock permitted below P-12 Automatically blocked above P-12
4.	**Main Feedwater Isolation** (Figure 7.2-1, Sheet 10) **(Closure of Control Valves)**			
a.	Safeguards actuation signal (automatic or manual)	(See items 1a through 1e)		
b.	Manual initiation	2 switches	1/2 switches	None
c.	High-2 steam generator narrow range level	4/steam generator	2/4-BYP[1] in either steam generator	None
d.	Low reactor coolant temperature (Low-1 T_{avg}) coincident with	2/loop	2/4 -BYP[1]	Manual block permitted below P-11 Automatically unblocked above P-11
	Reactor trip (P-4)	1/division	2/4	None

Table 7.3-1 (Sheet 3 of 8)

ENGINEERED SAFETY FEATURES ACTUATION SIGNALS

Actuation Signal	No. of Channels/ Switches	Actuation Logic	Permissives and Interlocks
(Trip of Main Feedwater Pumps and Closure of Isolation and Crossover Valves)			
a. Safeguards actuation signal (automatic or manual)	(See items 1a through 1e)		
b. Manual initiation	2 switches	1/2 switches	None
c. High-2 steam generator narrow range level	4/steam generator	2/4-BYP[1] in either steam generator	None
d. Low reactor coolant temperature (Low-2 T_{avg}) coincident with	2/loop	2/4-BYP1	Manual block permitted below P-11 Automatically unblocked above P-11
Reactor trip (P-4)	1/division	2/4	None
5. Reactor Coolant Pump Trip (Figure 7.2-1, Sheets 5, 7, 12, and 15) **(Trips All Reactor Coolant Pumps)**			
a. Safeguards actuation signal (automatic or manual)	(See items 1a through 1e)		
b. Automatic reactor coolant system depressurization (first stage)	(See items 3a through 3c)		
c. Low-2 pressurizer level	4	2/4-BYP[1]	Manual block permitted below P-12 Automatically unblocked above P-12
d. Low wide range steam generator water level coincident with	4/steam generator	2/4-BYP[1] in both steam generators	None
High reactor coolant outlet temperature (High T_{hot})[(8)]	2/loop	2/4-BYP[1]	None
e. Manual core makeup tank initiation	(See item 6e)		
(Trip Affected Pump)			
f. High reactor coolant pump water bearing temperature	4/pump	2/4-BYP[1] in affected pump	None

Table 7.3-1 (Sheet 4 of 8)

ENGINEERED SAFETY FEATURES ACTUATION SIGNALS

Actuation Signal	No. of Channels/ Switches	Actuation Logic	Permissives and Interlocks
6. Core Makeup Tank Injection (Figure 7.2-1, Sheets 7, 12 and 15)			
a. Safeguards actuation signal (automatic or manual)	(See items 1a through 1e)		
b. Automatic reactor coolant system depressurization (first stage)	(See items 3a through 3c)		
c. Low-2 pressurizer level	4	2/4-BYP[1]	Manual block permitted below P-12 Automatically unblocked above P-12
d. Low wide range steam generator water level coincident with	4/steam generator	2/4-BYP[1] in both steam generators	None
High reactor coolant outlet temperature (High T_{hot})[(8)]	2/loop	2/4-BYP[1]	None
e. Manual initiation	2 switches	1/2 switches	None
7. Turbine Trip (Figure 7.2-1, Sheet 14)			
a. Manual feedwater isolation	(See item 4b)		
b. Reactor trip (P-4)	1/division	2/4	None
c. High-2 steam generator narrow range level	4/steam generator	2/4-BYP[1] in either steam generator	None
8. Steam Line Isolation (Figure 7.2-1, Sheet 9)			
a. Manual initiation	2 switches	1/2 switches	None
b. High-2 containment pressure	4	2/4-BYP[1]	None
c. Low lead-lag compensated steam line pressure[4]	4/steam line	2/4-BYP[1] in either steam line	Manual block permitted below P-11 Automatically unblocked above P-11
d. High steam line negative pressure rate	4/steam line	2/4-BYP[1] in either steam line[7]	Manual unblock permitted below P-11 Automatically blocked above P-11
e. Low reactor coolant inlet temperature (Low T_{cold})	4/loop	2/4-BYP[1] either loop[6]	Manual block permitted below P-11 Automatically unblocked above P-11

Table 7.3-1 (Sheet 5 of 8)

ENGINEERED SAFETY FEATURES ACTUATION SIGNALS

Actuation Signal	No. of Channels/ Switches	Actuation Logic	Permissives and Interlocks
9. Steam Generator Blowdown System Isolation (Figure 7.2-1 Sheets 7 and 8)			
a. Passive residual heat removal heat exchanger actuation	(See items 12a through 12f)		
b. Low narrow range steam generator water level	4/steam generator	2/4 BYP[1] in either steam generator	None
10. Passive Containment Cooling Actuation (Figure 7.2-1, Sheet 13)			
a. Manual initiation	2 switches	1/2 switches	None
b. High-2 containment pressure	4	2/4-BYP[1]	None
11. Startup Feedwater Isolation (Figure 7.2-1, Sheets 9 and 10)			
a. Low reactor coolant inlet temperature (Low T_{cold})	4/loop	2/4-BYP[1] either loop[6]	Manual block permitted below P-11 Automatically unblocked above P-11
b. High-2 steam generator narrow range water level	4/steam generator	2/4-BYP[1] in either steam generator	None
c. Manual initiation of main feedwater isolation		(See item 4b)	
12. Passive Residual Heat Removal (Figure 7.2-1, Sheet 8)			
a. Manual initiation	2 switches	1/2 switches	None
b. Low narrow range steam generator water level coincident with	4/steam generator	2/4-BYP[1] in either steam generator	None
Low startup feedwater flow	2/feedwater line	1/2 in either feedwater line	None
c. Low steam generator wide range water level	4/steam generator	2/4-BYP[1] in either steam generator	None
d. Core makeup tank injection	(See Items 6a through 6e)		
e. Automatic reactor coolant system depressurization (first stage)	(See items 3a through 3c)		

Table 7.3-1 (Sheet 6 of 8)

ENGINEERED SAFETY FEATURES ACTUATION SIGNALS

Actuation Signal	No. of Channels/ Switches	Actuation Logic	Permissives and Interlocks
f. High-3 pressurizer level	4	2/4-BYP[1]	Manual block permitted below P-19 Automatically unblocked above P-19
13. Block of Boron Dilution (Figure 7.2-1, Sheets 3 and 15)			
a. Flux doubling calculation	4	2/4-BYP[1]	Manual block permitted above P-6 Automatically unblocked below P-6
b. Undervoltage to Class 1E battery chargers	2/charger	2/2 per charger and 2/4 chargers[5]	None
c. Reactor trip (P-4)	1/division	2/4	None
14. Chemical Volume Control System Isolation (See Figure 7.2-1, Sheets 6 and 11)			
a. High-2 pressurizer water level	4	2/4-BYP[1]	Automatically unblocked above P-19 Manual block permitted below P-19
b. High-2 steam generator narrow range level	4/steam generator	2/4-BYP[1] in either steam generator	None
c. Automatic or manual safeguards actuation signal coincident with	(See items 1a through 1e)		
High-1 pressurizer water level	4	2/4-BYP[1]	None
d. High-2 containment radioactivity	4	2/4-BYP[1]	None
e. Manual initiation	2 switches	1/2 switches	None
15. Steam Dump Block (Figure 7.2-1, Sheet 10)[(8)]			
a. Low reactor coolant temperature (Low-2 T_{avg}) coincident with	2/loop	2/4-BYP[1]	Manual block permitted below P-11 Automatically unblocked above P-11
Reactor trip (P-4)	1/division	2/4	None
b. Manual block	2 switches	1/division	None
16. Main Control Room Isolation and Air Supply Initiation (Figure 7.2-1, Sheet 13)			
a. High-2 control room supply air radiation	2	1/2	None

Table 7.3-1 (Sheet 7 of 8)

ENGINEERED SAFETY FEATURES ACTUATION SIGNALS

Actuation Signal	No. of Channels/ Switches	Actuation Logic	Permissives and Interlocks
b. Undervoltage to Class 1E battery chargers	2/charger	2/2 per charger and 2/4 chargers[5]	None
c. Manual initiation[(8)]	2 switches	1/2 switches	None
17. Auxiliary Spray and Purification Line Isolation (Figure 7.2-1, Sheet 12)			
a. Low-1 pressurizer level	4	2/4-BYP[1]	Manual block permitted below P-12 Automatically unblocked above P-12
b. Manual initiation of chemical and volume control system isolation	(See item 14e)		
18. Containment Air Filtration System Isolation (Figure 7.2-1, Sheets 11 and 13)			
a. Containment isolation	(See items 2a through 2c)		
b.. High-1 containment radioactivity	4	2/4-BYP[1]	None
19. Normal Residual Heat Removal System Isolation (Figure 7.2-1, Sheet 13)			
a. Automatic or manual safeguards actuation signal	(See items 1a through 1e)		
b. High-2 containment radioactivity	4	2/4-BYP[1]	Manual block permitted below P-11 Automatically unblocked above P-11
c. Manual initiation	4 switches	2/4 switches[3]	None
20. Refueling Cavity Isolation (Figure 7.2-1, Sheet 13)			
a. Low spent fuel pool level	3	2/3	None
21. Open In-Containment Refueling Water Storage Tank (IRWST) Injection Line Valves (Figure 7.2-1, Sheets 12 and 16)			
a. Automatic reactor coolant system depressurization (fourth stage)	(See items 3d and 3e)		
b. Coincident loop 1 and loop 2 Low-2 hot leg level (after delay)	1 per loop	2/2	Manual unblock permitted below P-12 Automatically blocked above P-12
c. Manual initiation	4 switches	2/4 switches[3]	None

Table 7.3-1 (Sheet 8 of 8)

ENGINEERED SAFETY FEATURES ACTUATION SIGNALS

Actuation Signal	No. of Channels/ Switches	Actuation Logic	Permissives and Interlocks
22. Open Containment Recirculation Valves In Series with Check Valves (Figure 7.2-1, Sheet 15)			
a. Extended undervoltage to Class 1E battery chargers(8)	2/charger	1/2 per charger and 2/4 charger	None
23. Open All Containment Recirculation Valves (Figure 7.2-1, Sheet 16)			
b. Automatic reactor coolant system depressurization (fourth stage)		(See items 3d through 3f)	
Low IRWST level (Low-3 setpoint)	4	2/4 BYP[1]	None
c. Manual initiation	4 switches	2/4 switches	None
24. Chemical and Volume Control System Letdown Isolation (Figure 7.2-1, Sheet 16)			
a. Low-1 hot leg level	1 per loop	1/2	None
25. Pressurizer Heater Block (Figure 7.2-1, Sheets 6 and 12)			
a. Core makeup tank injection	(See items 6a through 6e)		
b. High-3 pressurizer level	4	2/4 BYP[1]	Manual block permitted below P-19 Automatically unblocked above P-19
26. Steam Generator Relief Isolation (Figure 7.2-1, Sheet 9)			
a. Manual initiation	2 switches	1/2 switches	None
b. Low lead-lag compensated steam line pressure[4]	4/steam line	2/4-BYP[1] in either steam line	Manual block permitted below P-11 Automatically unblocked above P-11

Notes:

1. 2/4-BYP indicates automatic bypass logic. The logic is 2 out of 4 with no bypasses and 2 out of 3 with one bypass.
2. Any two channels from either tank not in same division.
3. Two switches must be actuated simultaneously.
4. Also, closes power-operated relief block valve of respective steam generator.
5. The two-out-of-four logic is based on undervoltage to the battery chargers for divisions A or C coincident with an undervoltage to the battery chargers for divisions B or D.
6. Any two channels from either loop not in same division.
7. Any two channels from either line not in same division.
8. This function does not meet the July 1993 Final Policy Statement on Technical Specification Improvements criteria and is not included in the Technical Specifications.

Table 7.3-2 (Sheet 1 of 4)

INTERLOCKS FOR ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

Designation	Derivation	Function
P-4	Reactor trip switchgear open (reactor trip)	(a) Permits manual reset of safeguards actuation signal to block automatic safeguards actuation (b) Isolates main feedwater if coincident with low reactor coolant temperature (c) Trips turbine (d) Blocks boron dilution
$\overline{\text{P-4}}$	Reactor trip switchgear closed	Automatically resets the manual block of automatic safeguards actuation
P-6	Intermediate range neutron flux channels above setpoint	Allows manual block of flux doubling actuation of the boron dilution block.
$\overline{\text{P-6}}$	Intermediate range neutron flux channels below setpoint	Prevents manual block of flux doubling actuation, permitting block of boron dilution
P-11	Pressurizer pressure below setpoint	(a) Permits manual block of safeguards actuation on low pressurizer pressure, low compensated steam line pressure, or low reactor coolant inlet temperature (b) Permits manual block of steam line isolation on low reactor coolant inlet temperature (c) Permits manual block of steam line isolation and steam generator power-operated relief valve block valve closure on low compensated steam line pressure (d) Coincident with manual actions of (b) or (c), automatically unblocks steam line isolation on high negative steam line pressure rate (e) Permits manual block of main feedwater isolation on low reactor coolant temperature

Table 7.3-2 (Sheet 2 of 4)

INTERLOCKS FOR ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

Designation	**Derivation**	**Function**
P-11 (continued)	Pressurizer pressure below setpoint	(f) Permits manual block of startup feedwater isolation on low reactor coolant inlet temperature (g) Permits manual block of steam dump block on low reactor coolant temperature (h) Permits manual block of normal residual heat removal system isolation on high containment radioactivity.
$\overline{\text{P-11}}$	Pressurizer pressure above setpoint	(a) Prevents manual block of safeguards actuation on low pressurizer pressure, low compensated steam line pressure, or low reactor coolant inlet temperature (b) Prevents manual block of steam line isolation on low reactor coolant inlet temperature (c) Prevents manual block of steam line isolation and steam generator power-operated relief valve block valve closure on low compensated steam line pressure (d) Automatic block of steam line isolation on high negative steam line pressure rate (e) Prevents manual block of feedwater isolation on low reactor coolant temperature (f) Prevents manual block of startup feedwater isolation on low reactor coolant inlet temperature (g) Prevents manual block of normal residual heat removal system isolation on high containment radioactivity

Table 7.3-2 (Sheet 3 of 4)

INTERLOCKS FOR ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

Designation	Derivation	Function
P-12	Pressurizer level below setpoint	(a) Permits manual block of core makeup tank actuation on low pressurizer level to allow mid-loop operation (b) Permits manual block of reactor coolant pump trip on low pressurizer level to allow mid-loop operation (c) Permits manual block of auxiliary spray and purification line isolation on low pressurizer level to allow mid-loop operation (d) Coincident with manual action of (a), automatically unblocks in-containment refueling water storage tank injection and fourth stage automatic depressurization system initiation on low hot leg level to provide protection during mid-loop operation.
$\overline{\text{P-12}}$	Pressurizer level above setpoint	(a) Prevents manual block of core makeup tank actuation on low pressurizer level (b) Prevents manual block of reactor coolant pump trip on low pressurizer level (c) Prevents manual block of auxiliary spray and purification line isolation on low pressurizer level (d) Provides confirmatory open signal to the core makeup tank cold leg balance lines (e) Automatically blocks in-containment refueling water storage tank injection and fourth stage automatic depressurization system initiation on low hot leg level to reduce the probability of spurious actuation.

Table 7.3-2 (Sheet 4 of 4)

INTERLOCKS FOR ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

Designation	Derivation	Function
P-19	Reactor coolant system pressure below setpoint	(a) Permits manual block of chemical and volume control system isolation on high pressurizer water level (b) Permits manual block of passive residual heat removal heat exchanger alignment on high pressurizer water level
$\overline{\text{P-19}}$	Reactor coolant system pressure above setpoint	(a) Prevents manual block of chemical and volume control system isolation on high pressurizer water level (b) Prevents manual block of passive residual heat removal heat exchanger alignment on high pressurizer water level

Table 7.3-3 (Sheet 1 of 2)

SYSTEM-LEVEL MANUAL INPUT TO THE ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

Manual Control	To Divisions				Figure 7.2-1 Sheet
Manual safeguards actuation #1	A	B	C	D	2 & 11
Manual safeguards actuation #2	A	B	C	D	2 & 11
Manual chemical and volume control system isolation #1	A		C	D	6
Manual chemical and volume control system isolation #2	A		C	D	6
Manual passive residual heat removal heat exchanger alignment #1	A	B		D	8
Manual passive residual heat removal heat exchanger alignment #2	A	B		D	8
Manual steam line isolation #1		B		D	9
Manual steam line isolation #2		B		D	9
Manual steam generator relief isolation #1		B		D	9
Manual steam generator relief isolation #2		B		D	9
Steam/feedwater isolation and safeguards block control #1	A				9
Steam/feedwater isolation and safeguards block control #2		B			9
Steam/feedwater isolation and safeguards block control #3			C		9
Steam/feedwater isolation and safeguards block control #4				D	9
Manual feedwater isolation #1		B		D	10
Manual feedwater isolation #2		B		D	10
Manual steam dump interlock selector #1		B			10
Manual steam dump interlock selector #2				D	10
Pressurizer pressure safeguards block control #1	A				11
Pressurizer pressure safeguards block control #2		B			11
Pressurizer pressure safeguards block control #3			C		11
Pressurizer pressure safeguards block control #4				D	11
Manual core makeup tank injection actuation #1	A	B	C	D	12
Manual core makeup tank injection actuation #2	A	B	C	D	12
Core makeup tank injection actuation block control #1	A				12
Core makeup tank injection actuation block control #2		B			12
Core makeup tank injection actuation block control #3			C		12
Core makeup tank injection actuation block control #4				D	12
Manual passive containment cooling actuation #1	A	B	C		13
Manual passive containment cooling actuation #2	A	B	C		13
Manual passive containment isolation actuation #1	A	B	C	D	13
Manual passive containment isolation actuation #2	A	B	C	D	13

Table 7.3-3 (Sheet 2 of 2)

SYSTEM-LEVEL MANUAL INPUT TO THE ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

Manual Control	To Divisions				Figure 7.2-1 Sheet
Manual depressurization system stages 1, 2, and 3 actuation #1 & #2	A	B	C	D	15
Manual depressurization system stages 1, 2, and 3 actuation #3 & #4	A	B	C	D	15
Manual depressurization system stage 4 actuation #1 & #2	A	B	C	D	15
Manual depressurization system stage 4 actuation #3 & #4	A	B	C	D	15
Manual IRWST injection actuation #1 & #2	A	B	C	D	16
Manual IRWST injection actuation #3 & #4	A	B	C	D	16
Manual containment recirculation actuation #1 & #2	A	B	C	D	16
Manual containment recirculation actuation #3 & #4	A	B	C	D	16
Manual control room isolation and air supply initiation #1	A	B	C	D	13
Manual control room isolation and air supply initiation #2	A	B	C	D	13
RCS pressure CVS/PRHR block control #1	A				6
RCS pressure CVS/PRHR block control #2		B			6
RCS pressure CVS/PRHR block control #3			C		6
RCS pressure CVS/PRHR block control #4				D	6
Normal residual heat removal system isolation safeguards block control #1	A				13
Normal residual heat removal system isolation safeguards block control #2		B			13
Boron dilution block control #1	A				3
Boron dilution block control #2		B			3
Boron dilution block control #3			C		3
Boron dilution block control #4				D	3
Manual RNS isolation #1 & #3	A	B		D	18
Manual RNS isolation #2 & #4	A	B		D	18

Table 7.3-4 (Sheet 1 of 2)

ENGINEERED SAFETY FEATURES ACTUATION, VARIABLES, LIMITS, RANGES, AND ACCURACY'S (NOMINAL)

Variable to be Monitored	Range of Variable	Typical Accuracy	Typical Response Time (Sec)
Pressurizer pressure	1700 to 2500 psig	±2.5% of span	1.2[(1)]
Steam line pressure	0 to 1200 psig	±3.0% of span	1.2[(1)]
Steam line negative pressure rate	0 to 250 psig/sec	±0.5% of span	1.6[(2)]
Reactor coolant inlet temperature (T_{cold})	490 to 610°F	±2.5% of span	6.0[(1)]
Reactor coolant outlet temperature (T_{hot})	530 to 650°F	±3.5% of span	6.0[(1)]
Containment pressure	-5 to 10 psig	±3.0% of span	1.2[(1)]
Reactor coolant system hot leg level	0 to 100% of span	±3.0% of span	1.6[(1)]
In-containment refueling water storage tank level	0 to 100% of span	±1.0% of span	1.6[(1)]
Undervoltage on ac buses	250 to 400 V	±6.5% of setpoint	1.5[(1)]
Steam generator narrow range water level	0 to 100% of span (narrow range taps)	±2% of span	1.6[(1)]
Steam generator wide range water level	0 to 100% of span (wide range taps)	±15.5% of span	1.6[(1)]
Core makeup tank narrow range upper water level	0 to 100% of span	±6% of span	1.6[(1)]
Core makeup tank narrow range lower water level	0 to 100% of span	±6% of span	1.6[(1)]
Reactor coolant pump bearing temperature	70 to 450°F	±1.0% of span	2.0[(1)]
Spent fuel pool level	0 to 28 feet	±3.0% of span	1.6[(1)]
Reactor coolant system wide range pressure	0 to 3300 psig	±3.0 of span	1.2[(1)]

Table 7.3-4 (Sheet 2 of 2)

ENGINEERED SAFETY FEATURES ACTUATION, VARIABLES, LIMITS, RANGES, AND ACCURACIES (NOMINAL)

Variables to be Monitored	Range of Variables	Typical Accuracy	Typical Response Time (Sec)
Pressurizer water level	0 to 100% of cylindrical portion of pressurizer	± 2.25% of span	1.2[(1)]
Startup feedwater flow	0 to 1000 gpm	4.0% of span	1.6[(1)]
Neutron flux (flux doubling calculation)	1 to 10^6 c/sec	± 11.0% of span	10.0[(1)(3)]
Control room supply air radiation level	10^{-7} to 10^{-2} µ Ci/cc	± 5.0% of full scale	5.0[(1)]
Containment radioactivity	10^0 to 10^7 R/hr	± 5.0% of full scale	5.0[(1)]

Notes:

1. Listed response time is the time for a step change of a variable, from 5% below to 5% above the setpoint, to reach the actuated device.
2. Listed response time is the time for a negative 20% step change of steam line pressure to reach the actuated device.
3. Response time depends on time constant settings.

7.4 Systems Required for Safe Shutdown

Systems to establish safe shutdown conditions perform two basic functions. First, they provide the necessary reactivity control to maintain the core in a subcritical condition. Boration capability is provided to compensate for xenon decay and to maintain the required core shutdown margin. Second, these systems must provide residual heat removal capability to maintain adequate core cooling.

The designation of systems required for safe shutdown depends on identifying those systems that provide the following capabilities for maintaining a safe shutdown:

- Decay heat removal
- Reactor coolant system inventory control
- Reactor coolant system pressure control
- Reactivity control

There are two different safe shutdown conditions that are expected following a transient or accident condition. Short-term safe shutdown refers to the plant conditions from the start of an event until about 36 hours later. Long-term safe shutdown refers to the plant conditions after this 36-hour period.

The short-term safe shutdown conditions include maintaining the reactor subcritical, the reactor coolant average temperature less than or equal to no load temperature, and adequate coolant inventory and core cooling. These shutdown conditions shall be achieved following any of the design basis events using safety-related equipment. The specific safe shutdown condition achieved is a function of the particular accident sequence.

The long-term safe shutdown conditions are the same as the short-term conditions except that the coolant temperature shall be less than 420°F. This long-term condition must be achieved within 36 hours and maintained indefinitely using safety-related equipment.

There are no systems specifically and solely dedicated as safe shutdown systems. However, there are a number of plant systems that are available to establish and maintain safe shutdown conditions. Normally, in the event of a turbine or reactor trip, nonsafety-related plant systems automatically function to place the plant in short-term safe shutdown, as described in subsection 7.4.1.2. During the short-term safe shutdown condition, an adequate heat sink is provided to remove reactor core residual heat and boration control is available. Redundancy of systems and components is provided to enable continued maintenance of the short-term safe shutdown condition. Additional redundant nonsafety-related systems are normally available to manually perform a plant depressurization and cooldown.

The engineered safety systems are designed to establish and maintain safe shutdown conditions for the plant. Nonsafety-related systems are not required for safe shutdown of the plant.

This section focuses on safety-related systems used to establish and maintain safe shutdown conditions. The discussion of safe shutdown does not include accident response and/or mitigation since the standard review plan for this section addresses safe shutdown not related to accident

mitigation. However, safe shutdown conditions are also established and maintained by these safety-related systems following accident conditions. For example, the control rods are released to initially place the plant in a shutdown condition to mitigate the consequences of various accidents. The passive core cooling system, on the other hand, is used to provide core cooling in an accident, but it is also one of the principal systems used for safe shutdown. Only those specific engineered safety systems listed in Table 7.4-1 are used to establish and maintain safe shutdown of the plant. These engineered safety systems automatically function to place the plant in a safe shutdown condition without operator action.

The instrumentation functions necessary for safe shutdown are available through instrumentation channels associated with the safety-related systems in the primary plant. These channels automatically actuate the protective functions provided by the safety-related systems. Manual actuation of the associated safety-related systems is also provided.

The instrumentation systems discussed in this section are those which are required during nonaccident conditions to align the safety-related systems and perform the specified safe shutdown functions.

The specific systems available for safe shutdown are discussed in subsection 7.4.2. and are listed in Table 7.4-1.

Maintenance of safe shutdown conditions with these systems, and the associated instrumentation and controls, includes consideration of the accident consequences that might challenge safe shutdown conditions. The accident consequences that are germane are those that tend to degrade the capabilities for coolant circulation, boration, heat removal, and depressurization. Safe shutdown is achieved following any of the accidents analyzed in Chapter 15. The specific safe shutdown condition reached is a function of the particular accident sequence.

The instrumentation and controls discussed in subsection 7.4.1 are used to control and/or monitor shutdown. These safety-related systems allow the maintenance of safe shutdown, even under accident conditions that tend toward a return to criticality or a loss of heat sink.

In addition to the operation of safety-related systems used for safe shutdown, as described in subsection 7.4.1, the following are part of the safe shutdown provisions:

- The turbine is tripped. (This can be accomplished at the turbine as well as from the main control room.)

- The reactor is tripped. (This can be accomplished at the reactor trip switchgear as well as from the main control room.)

- Support of engineered safety systems actuation is provided by safety-related onsite dc power.

7.4.1 Safe Shutdown

7.4.1.1 Safe Shutdown Using Safety-Related Systems

The following describes the process that establishes safe shutdown conditions for the plant, using the safety-related systems, and no operator action. The reactor coolant system is assumed to be intact for this discussion of safe shutdown.

Since this discussion only considers the use of safety-related systems, offsite electrical power sources are assumed to be lost at the start of the event. This results in a loss of the reactor coolant pumps. Even though the reactor coolant pumps are tripped during the initiation of certain engineered safety system actuation, it is assumed that no engineered safety system actuation signal is generated for this initiating event. With loss of the reactor coolant pumps, reactor coolant system natural circulation flow initiates and transfers core heat to the steam generators. Since feedwater flow is lost, the existing steam generator water inventory provides initial decay heat removal capability.

The initial loss of main ac power results in the Class 1E dc batteries automatically supplying power to the Class 1E dc power distribution network and the four Class 1E 120 Vac instrumentation divisions via the inverters.

The initial response of the passive safety systems is to actuate the passive residual heat removal heat exchanger due to low steam generator water level. The passive residual heat removal heat exchanger removes decay heat from the core by transferring this heat to the in-containment refueling water storage tank.

The passive residual heat removal heat exchanger removes core decay heat, cooling the reactor coolant system. As reactor coolant system cooldown continues, the reactor coolant system pressure decreases due to contraction of the reactor coolant system inventory since the pressurizer heaters are de-energized. An engineered safety system actuation signal occurs when reactor coolant system pressure decreases below a setpoint. This actuates the core makeup tanks, if they had not been previously actuated due to low pressurizer level. The core makeup tanks provide borated water injection to the reactor coolant system.

The engineered safety system actuation signal generated on low pressurizer pressure also actuates containment isolation. This prevents loss of water inventory from containment and permits indefinite operation of the passive residual heat removal heat exchanger and the in-containment refueling water storage tank.

The in-containment refueling water storage tank starts to boil about one to two hours after passive residual heat removal operation is initiated. Once boiling occurs, the in-containment refueling water storage tank begins steaming to containment, transferring heat to the air flowing on the outside of the containment shell. As steaming to containment continues, containment pressure slowly increases. As containment pressure slowly increases, an engineered safety system actuation signal is generated on containment high pressure, resulting in the initiation of passive containment cooling. This provides water flow on the outside of the containment shell to improve the heat removal performance from containment through evaporative cooling to the outside air.

A gutter located at the operating deck elevation collects condensate from the inside of the containment shell. Valves located in drain lines from the gutter to the containment waste sump close on a passive residual heat removal heat exchanger actuation signal. This action diverts the condensate to the in-containment refueling water storage tank. The system indefinitely provides core decay heat removal in this configuration without a significant increase in the containment water level.

Once the reactor coolant system and the safety systems are in this configuration, the plant is in a stable shutdown condition. The reactor coolant system temperatures and pressures continue to slowly decrease. The passive residual heat removal heat exchanger cools the reactor coolant system to 420°F in 36 hours.

Operation in this configuration may be limited in time duration by reactor coolant system leakage. The core makeup tanks can only supply a limited amount of makeup in the event there is reactor coolant system leakage. Eventually the volume of the water in the core makeup tanks will decrease to the first stage automatic depressurization setpoint. The time to reach this setpoint depends upon the reactor coolant system leak rate and the reactor coolant cooldown.

The Class 1E dc batteries that power the automatic depressurization system valves provide power for at least 24 hours. There is a timer that measures the time that ac power sources are unavailable. This timer provides for automatic actuation of the automatic depressurization system before the Class 1E dc batteries are discharged. The emergency response guidelines direct the operator to assess the need for automatic depressurization before the timer completes its count (approximately 22 hours). The operator assessment includes consideration for a visible refueling water storage tank level, full core makeup tanks, and a high and stable in-containment refueling water storage tank level. If automatic depressurization is not needed, the operator is directed to de-energize all loads on the Class 1E dc batteries. This action preserves the capability for the operator to initiate automatic depressurization at a later time.

The automatic depressurization system can be manually initiated by the operator at any time, but no operator action is needed to provide safe shutdown conditions. Once the automatic depressurization system sequence initiates, the plant automatically transitions to lower pressure and temperature conditions that establish and maintain long-term safe shutdown of the plant.

When the automatic depressurization system is actuated, the first stage depressurization valves open and the reactor coolant system depressurization starts. The second and third stage depressurization valves open in sequence, based on automatic timers that are started upon the actuation of the first stage depressurization valves. As reactor coolant inventory continues to be lost, the core makeup tanks continue to inject. If the volume of the water in the core makeup tanks decrease to the fourth stage automatic depressurization setpoint, the fourth stage depressurization valves open. The water and steam vented from the reactor coolant system initially flows into the in-containment refueling water storage tank and overflows into the refueling canal. Eventually this overflows into the reactor vessel cavity, where any moisture from the fourth stage automatic depressurization system valves also collects from discharge in the loop compartments. This overflow initiates the floodup of containment, along with condensate from the containment shell and other cool surfaces in containment.

As the reactor coolant system pressure decreases, the accumulators inject borated water into the reactor coolant system. After the fourth stage automatic depressurization system valves open, the reactor coolant system pressure is reduced sufficiently so that in-containment refueling water storage tank injection can begin as the core makeup tanks empty.

The drain down of the in-containment refueling water storage tank is relatively slow, depending on the injection rates and the reactor coolant system pressure. As the in-containment refueling water storage tank continues to inject, the containment floodup also continues and eventually the floodup volume is sufficient to initiate flow from the recirculation sump.

As the reactor coolant system voids during the cooldown and depressurization process, water flow through the passive residual heat removal heat exchanger is replaced by steam flow, which also provides core cooling. As the in-containment refueling water storage tank empties and uncovers the passive residual heat removal heat exchanger, heat transfer via this path decreases. Eventually, the passive residual heat removal heat exchanger is uncovered, heat removal by the passive residual heat removal heat exchanger stops, and decay heat is removed by automatic depressurization system venting.

The final long-term safe shutdown plant conditions are maintained with the reactor coolant system depressurized to about 10 psig at saturated conditions, venting steam through the automatic depressurization system valves to containment, with heat transferred to the outside atmosphere via the passive containment cooling system. With containment isolation established, the water inventory inside containment provides an indefinite cooling water supply for core decay heat removal.

7.4.1.2 Safe Shutdown Using Safety-Related and Nonsafety-Related Systems

This subsection describes situations where nonsafety-related features of the plant are used together with safety-related systems to establish safe shutdown conditions. As discussed in subsection 7.4.1.1, the AP1000 can be placed in a safe shutdown condition and maintained there using safety-related systems and no operator actions. Section 6.3 provides additional discussion of these situations.

Following passive residual heat removal heat exchanger actuation, the in-containment refueling water storage tank heats up and starts to boil after several hours of operation. If normal steam generator heat removal is not re-established, the operators align the normal residual heat removal system to cool the in-containment refueling water storage tank. This operation prevents significant steaming to the containment.

In case the automatic depresurization system is actuated, the operators align the normal residual heat removal system to provide injection to the reactor coolant system. This action causes the core makeup tank level to remain above the fourth stage valve actuation setpoint and prevents significant steaming to and flooding of the containment.

7.4.1.3 Safe Shutdown Using Nonsafety-Related Systems

This subsection describes the process to establish and maintain safe shutdown conditions using the nonsafety-related systems. As discussed in Section 7.4, the review of the plant safe shutdown capability, including the capabilities provided by the nonsafety-related systems, does not include accident response or mitigation. The nonsafety-related systems normally used to support plant shutdown operations are expected to be available. Offsite power is also expected to be available to support safe shutdown operations, although the nonsafety-related systems can establish and maintain safe shutdown conditions using only onsite electrical power.

For the purposes of this discussion, the nonsafety-related system operation following a reactor trip is described. As assumed in the discussion in subsection 7.4.1.1 on safe shutdown using safety-related systems, the reactor coolant system is assumed to be intact during plant safe shutdown operations.

The nonsafety-related systems and equipment used to establish and maintain safe shutdown conditions are the same systems and equipment that are operated during normal plant startup and shutdown evolutions. The safe shutdown capability using the safety-related systems, described in subsection 7.4.1.1, is only expected to be used in the event that the nonsafety-related systems are not available.

The nonsafety-related systems operate to establish and maintain safe shutdown conditions by providing the safe shutdown functions described in Section 7.4, except that reactivity control is only needed for long-term safe shutdown. If offsite power is available, the operation of these nonsafety-related systems is automatic.

The nonsafety-related systems actuate to establish and maintain the short-term safe shutdown conditions. The systems can also establish and maintain long-term safe shutdown conditions within the time limits discussed in Section 7.4. The operational philosophy following any event is to maintain appropriate safe shutdown conditions based on the duration of the shutdown, until the plant is able to re-start.

Cold shutdown conditions would only be established if it becomes necessary for equipment repair or due to limitations of the nonsafety-related systems in maintaining safe shutdown conditions (such as feedwater system water inventory). This philosophy reduces unnecessary challenges to plant safety due to the transition from operating systems to infrequently-operated standby systems.

Normally, offsite electrical power is available and the nonsafety-related systems automatically maintain short-term safe shutdown conditions as follows:

- Reactor coolant system forced flow to the steam generators by the reactor coolant pumps
- Feedwater from the main or startup feedwater systems
- Heat removal by the steam generators to the main condenser using turbine bypass valves
- Condenser heat removal provided by the main circulating water system

- Reactor coolant system inventory and boration control by the chemical and volume control system

- Reactor coolant system pressure control using pressurizer heaters and normal spray

If offsite power is not available, the reactor coolant pumps, main feedwater pumps, and main circulating water pumps will not be operating. However, the nonsafety-related systems maintain short-term safe shutdown conditions without offsite electrical power as follows:

- Electrical power provided to the required nonsafety-related systems by the diesel-generators of the onsite standby power system

- Heat removal by the steam generators directly to the atmosphere through the power-operated relief valves

- Feedwater from the startup feedwater system

- Reactor coolant system flow to the steam generators via natural circulation

- Reactor coolant system inventory and boration control by the chemical and volume control system

- Reactor coolant system pressure control using pressurizer heaters and auxiliary spray

In case the main feedwater is unavailable, the initial response of the nonsafety-related systems following a reactor trip is to automatically actuate the startup feedwater system, on low steam generator water level, to provide decay heat removal. The steam generators can remove decay heat from the core by either forced or natural circulation in the reactor coolant system. If offsite electrical power is available, the reactor coolant pumps continue to provide forced circulation in the reactor coolant system and the circulating water system continues to operate to provide a heat sink for the steam discharged from the steam generators to the main condenser.

With offsite power and the main condenser available, the turbine bypass valves automatically actuate after the reactor trip to control reactor coolant system temperature, based on the pre-set steam generator pressure control set point that is normally established for standby turbine bypass valve operation. The main feedwater system or the startup feedwater system automatically maintains steam generator water level as the turbine bypass valves continue to throttle steam flow to match the decreasing core decay heat levels. The pressurizer heaters and spray automatically maintain reactor coolant system subcooling with pressure at normal reactor coolant system conditions.

The chemical and volume control system makeup pumps automatically actuate as required to provide borated makeup water to maintain pressurizer level in the programmed band for no-load conditions. The makeup source is the boric acid tank which provides long-term reactivity control. The makeup pumps are expected to operate infrequently during these conditions to compensate for normal reactor coolant system inventory losses such as valve leakage.

Operation of the nonsafety-related systems in this mode maintains short-term safe shutdown conditions and reactor coolant system temperature and pressure remain near no-load conditions. If it becomes necessary to perform a plant cooldown and depressurization to establish long-term safe shutdown conditions, the nonsafety-related systems are used, following the normal plant cooldown procedures. Manual boration to the cold shutdown boron concentration is provided by the chemical and volume control system by initiating reactor coolant system letdown in combination with makeup pump operation. After the boration is completed and letdown is secured, the makeup pumps automatically maintain reactor coolant system inventory throughout the remainder of the cooldown process.

After the required boration is completed the turbine bypass valves are used to initiate the cooldown, with manual control of pressurizer heaters and spray to maintain the reactor coolant system pressure, temperature, and cooldown rate within the limits specified in the technical specifications. The main feedwater system automatically provides feedwater and maintains steam generator level throughout the cooldown process.

When the reactor coolant system temperature and pressure are reduced to within the capabilities of the normal residual heat removal system, at approximately 350°F and 400 psig, the system is manually aligned to the reactor coolant system and started to continue the cooldown process. The final long-term safe shutdown conditions established would be dependent upon the specific maintenance required.

The use of the nonsafety-related systems and equipment for both short-term and long-term safe shutdown also requires the operation of associated support systems. These normally operating support systems include component cooling water, chilled water, compressed air, area ventilation, and nonsafety-related instrumentation and control power. These systems are started as required following a loss of offsite power, once the nonsafety-related diesel-generators are started.

If offsite electrical power is unavailable, the nonsafety-related systems actuate to establish and maintain safe shutdown conditions. There are some differences in the decay heat discharge flow path and the reactor coolant system remains at a slightly higher temperature resulting from the natural circulation flow conditions. With the loss of offsite electrical power, the nonsafety-related diesel-generators provide electrical power for the required nonsafety-related equipment. However, the reactor coolant pumps, main feedwater pumps, and main circulating water pumps are not available. Therefore, core decay heat is transferred to the steam generators using natural circulation in the reactor coolant system, the startup feedwater pumps supply the steam generators, and the steam generators discharge directly to the atmosphere to remove decay heat.

When offsite electrical power is unavailable, reactor coolant temperature is automatically maintained by the steam generator atmospheric power-operated relief valves instead of the turbine bypass valves. The steam generator power-operated relief valves maintain a pre-set steam generator pressure by throttling the steam discharged directly from the steam generators to the atmosphere. The relief valve operation maintains a slightly higher steam generator pressure than the pressure maintained with turbine bypass valve standby operation, resulting in a slight increase in the reactor coolant system temperature. The automatic operation of the startup feedwater subsystem maintains steam generator inventory with the pumps powered from the diesel-

generators. In addition, the direct discharge of steam to the atmosphere prevents condensate recovery, which limits the water inventory for the startup feedwater system.

Following a loss of offsite power, the reactor coolant system temperature is slightly higher than for a reactor trip when offsite electrical power is available, resulting from natural circulation flow and steam generator power-operated relief valve operation. Since the transition to natural circulation flow is relatively slow, the reactor coolant system pressure remains stable without operator action. Operator action is not required to maintain reactor coolant system pressure.

Without offsite electrical power, the pressurizer heaters are manually re-energized after the diesel-generators start. Without reactor coolant pump operation, normal pressurizer spray is unavailable to counteract system pressure increases. Therefore, auxiliary spray provided by the chemical and volume control system makeup pumps is manually initiated to decrease reactor coolant system pressure, if necessary. The operation of the chemical and volume control system makeup pumps to maintain reactor coolant system inventory is similar to their operation when offsite power is available, except that the pumps are manually controlled and powered from the diesel-generators.

The nonsafety-related systems are normally expected to maintain short-term safe shutdown conditions when offsite power is not available. If it is required to establish long-term safe shutdown conditions for equipment maintenance, the cooldown would normally be delayed until offsite power is recovered.

However, the nonsafety-related systems can be used to perform a natural circulation cooldown, if necessary. When performing a natural circulation plant cooldown and depressurization, the operation of the nonsafety-related systems is similar to the normal cooldown operation except that they are powered from the diesel-generators. The primary difference in operation is the use of the steam generator power-operated relief valves to control the cooldown process.

7.4.2 Safe Shutdown Systems

To effect a safe shutdown, with safety-related systems, the plant is initially brought to a stable condition with heat removal provided by the passive residual heat removal heat exchanger. For safe shutdown conditions, control is possible from either the main control room or the remote shutdown workstation. To accomplish a safe shutdown, the functions required are: coolant circulation, boration, heat removal, and depressurization. The portions of the protection and safety monitoring system required to achieve the safe shutdown condition are described in Sections 7.2 and 7.3. The minimum systems required to maintain safe shutdown conditions under a nonaccident condition are listed and discussed in the following paragraphs.

7.4.2.1 Passive Core Cooling System

A description of the passive core cooling system and its operation is provided in Section 6.3. The passive residual heat removal heat exchanger, the core makeup tanks, the in-containment refueling water storage tank, the containment recirculation, and the automatic depressurization system actuate automatically. They can also be manually initiated. Actuation controls are located at the remote shutdown workstation as well as in the main control room.

The safety injection flow from the accumulators, initiates automatically by the reactor coolant system depressurization process. The operation of the accumulator is integrated with the automatic actuation of the other passive core cooling subsystems.

7.4.2.2 Passive Containment Cooling System

A description of the passive containment cooling system and its operation is provided in subsection 6.2.2. The passive containment cooling system actuates automatically. It also can be manually initiated. Actuation controls are located at the remote shutdown workstation as well as in the main control room.

7.4.2.3 Containment Isolation

A description of containment isolation valves and their operation is provided in various subsections. Each system that has piping that penetrates the containment vessel and therefore, requires containment isolation valves is discussed in its own subsection. Most of these systems are nonsafety-related; however, the containment isolation valves and the associated piping are safety-related and automatically close on a safeguards actuation (S) signal. The containment isolation system is discussed in subsection 6.2.3.

7.4.2.4 Reactor Coolant System Circulation

The preferred method of coolant circulation is forced circulation with the reactor coolant pumps supplying the driving head. Upon the loss of main ac power, or when the reactor coolant pumps are tripped during engineered safety system actuation, the reactor coolant pumps are not available. However, the reactor coolant system is designed to provide sufficient natural circulation to achieve safe shutdown conditions with the steam generators and passive residual heat removal heat exchanger removing decay heat. Natural circulation flow is verified by monitoring the reactor coolant system temperatures.

7.4.2.5 Other Systems Required for Safe Shutdown

The other safety-related equipment and systems used to maintain the plant in safe shutdown are identified in Table 7.4-1. They are also listed below, with a reference to the respective section or subsection which discusses their operation in more detail:

- Protection and safety monitoring system — Sections 7.2, 7.3, and 7.5
- Class 1E dc and UPS system — Subsection 8.3.2

These systems are either normally operating or they start automatically when required. The instrumentation for these systems is described in the particular section containing the system description.

The monitoring instrumentation available in the main control room for safe shutdown are safety-related and are part of the protection and safety monitoring system. The instrumentation available for safe shutdown monitoring is listed in Section 7.5.

7.4.3 Safe Shutdown from Outside the Main Control Room

7.4.3.1 Description

If temporary evacuation of the main control room is required because of some abnormal main control room condition, the operators can establish and maintain safe shutdown conditions for the plant from outside the main control room through the use of controls and monitoring located at the remote shutdown workstation. Safe shutdown is a stable plant condition that can be maintained for an extended period of time. In the event that access to the main control room is restricted, the plant is maintained in safe shutdown until the main control room can be re-entered.

7.4.3.1.1 Remote Shutdown Workstation

Safe shutdown can be established and maintained from the remote shutdown workstation. The workstation is designed to allow control of a shutdown following an evacuation of the control room, coincident with the loss of offsite power and a single active failure. No other design basis event is postulated. Subsection 9.5.1 provides a discussion of shutdown in the event of a fire. The remote shutdown workstation equipment is similar to the operator workstations in the main control room and is designed to the same standards.

One remote shutdown workstation is provided. The remote shutdown workstation contains controls, displays, and alarms for the safety-related equipment required to establish and maintain safe shutdown. Additionally, control of nonsafety-related components is available, allowing operation and control when ac power is available. The design basis for the remote shutdown workstation does not require the installation of safety-related, dedicated, fixed-position displays, alarms, and controls. The remote shutdown workstation has the same capabilities as the reactor operator's workstation in the main control room. The controls, displays, and alarms listed in Table 18.12.2-1 are retrievable from the remote shutdown workstation. Subsection 18.12.3 provides more discussion on the remote shutdown workstation displays, alarms, and controls.

The remote shutdown workstation is provided for use only following an evacuation of the main control room. No actions are anticipated from the remote shutdown workstation during normal, routine shutdown, refueling, or maintenance operations.

The remote shutdown workstation has sufficient communication circuits to allow the operator to effectively establish safe shutdown conditions. As detailed in subsection 9.5.2, communication is available between the following stations:

- Main control room
- Remote shutdown workstation
- Onsite technical support center
- Diesel generator local control station

Operator control capability at the remote shutdown workstation is normally disabled, and operator control functions are normally performed from workstations located inside the main control room; however, operator control capability can be transferred from the main control room workstations to the remote shutdown workstation if the control room requires evacuation. Procedures will

instruct the operator to trip the reactor prior to evacuating the control room and transferring control to the remote shutdown workstation. This operator control transfer capability cannot be disabled by any single active failure coincident with the loss of offsite power.

The control transfer function is implemented by multiple transfer switches. Each individual transfer switch is associated with only a single safety-related or single nonsafety-related group. These switches are located behind an unlocked access panel. Entry into this access panel will result in alarms at the main control room and remote shutdown workstation. The access panel is located within a fire zone which is separate from the main control room. Actuation of these transfer switches results in additional alarms at the main control room and remote shutdown workstation, the activation of operator control capability from the remote workstation, and the deactivation of operator control capability from the main control room workstations. This deactivation of operator control capability includes deactivation of all operator control capability provided by the soft control devices described in subsection 7.1.3.3 and deactivation of all operator control capability provided by dedicated switches. This includes deactivation of operator control capability using manual actuation functions provided by the diverse actuation system as described in subsection 7.7.1.11. The manual reactor trip switches located in the main control room are not affected by this control transfer function. The operator displays, located in the main control room and on the remote shutdown workstation, are also not affected by this control transfer function. The displays on the remote shutdown workstation are operational during normal operation (from the main control room) so that they can be used with no delay if transfer to the remote shutdown workstation is required.

7.4.3.1.2 Controls at Other Locations

In addition to the controls and indicators provided at the remote shutdown workstation, the following controls are provided outside the main control room:

- Reactor trip capability at the reactor trip switchgear
- Turbine trip capability at the turbine
- Start/stop controls for the diesel generators, located at each diesel generator local control panel
- Local control at motor control centers and electrical switchgear.

7.4.3.1.3 Design Bases Information

According to GDC 19, the capability of establishing a shutdown condition and maintaining the station in a safe status in that mode is an essential function. The controls and indications necessary for this function are identified in subsection 7.4.2. To provide the availability of the remote shutdown workstation after control room evacuation, the following design features are provided:

- The remote shutdown workstation conforms with the guidelines provided by ANSI 58.6 1996 (Reference 1).

- The remote shutdown workstation achieves and maintains safe shutdown conditions from full power conditions and maintains safe shutdown conditions thereafter.

- The remote shutdown workstation achieves safe shutdown when offsite power is available and when offsite power is not available.

- The remote shutdown workstation operates safety-related systems, independent from the main control room.

- The remote shutdown workstation is designed for a single failure. When a random event, such as a fire, or an allowable technical specification maintenance results in one safety-related division being unavailable, a single failure in a redundant division is not postulated. When a random event other than fire causes a main control room evacuation, a coincident single failure in the systems controlled from the remote shutdown workstation is considered.

- Access to the remote shutdown workstation is under administrative control.

7.4.3.2 Analysis

The analysis of the systems required for safe shutdown is provided in subsection 7.4.1. The following discussion is limited to the remote shutdown workstation.

Conformance to NRC General Design Criteria

General Design Criterion 19 – The remote shutdown workstation provides adequate controls and indications located outside the main control room to establish and maintain the reactor and the reactor coolant system in a safe shutdown condition in the event that the main control room must be evacuated.

Conformance to NRC Regulatory Guides

Regulatory Guide 1.22 – The remote shutdown workstation is tested periodically during station operation.

Regulatory Guide 1.29 – The remote shutdown workstation is designed as seismic Category II to prevent compromising the function of safety-related devices during or after a safe shutdown earthquake.

Conformance to IEEE 603-1991

The remote shutdown workstation and the design features which provide for the transfer of control capability from the main control room to the remote shutdown workstation conforms to applicable portions of IEEE 603-1991. The circuits which perform the control transfer function are designed so that a single failure does not prevent maintaining safe shutdown. This is accomplished by redundant components in the systems required for safe shutdown, using independent safety-related power divisions.

To prevent interaction between the redundant systems, the redundant control channels are wired independently and are separated from each other. Nonsafety-related circuits available for (but not required for) safe shutdown are electrically isolated from safety-related circuits.

7.4.4 Combined License Information

This section has no requirement for information to be provided in support of the Combined License application.

7.4.5 References

1. ANSI 58.6 1996, "Criteria for Remote Shutdown for Light Water Reactors."

Table 7.4-1

SYSTEMS REQUIRED FOR SAFE SHUTDOWN

Protection and Safety Monitoring System
Passive Core Cooling System
Passive Residual Heat Removal Heat Exchanger
Core Makeup Tanks
Accumulators
In-Containment Refueling Water Storage Tank
Automatic Depressurization Valves
Passive Containment Cooling System
Class 1E dc and UPS System
Containment Isolation Valves
Reactor System
Control Rods

7.5 Safety-Related Display Information

7.5.1 Introduction

An analysis is conducted to identify the appropriate variables and to establish the appropriate design bases and qualification criteria for instrumentation employed by the operator for monitoring conditions in the reactor coolant system, the secondary heat removal system, the containment, and the systems used for attaining a safe shutdown condition. This selection of monitored variables is based on the guidance provided in Regulatory Guide 1.97. The variables and instrument design criterion selected for the AP1000 is described in subsections 7.5.2 and 7.5.3.

The safety-related display information is used by the operator to monitor and maintain the safety of the AP1000 throughout operating conditions that include anticipated operational occurrences and accident and post-accident conditions. The equipment which processes the safety-related display information and makes it available to the operator is discussed in subsection 7.5.4.

7.5.2 Variable Classifications and Requirements

Accident monitoring instrumentation is necessary to permit the operator to take actions to address design basis accident situations and for unforeseen situations (should plant conditions evolve differently than predicted by the safety analyses, the control room operating staff has sufficient information to evaluate and monitor the course of the event). Additional instrumentation is needed to indicate to the operating staff whether the integrity of the fuel cladding, the reactor coolant pressure boundary, or the reactor containment has degraded beyond the prescribed limits defined in the plant safety analyses and other evaluations.

Six types of variables are classified to provide this instrumentation:

- Variables that provide information needed by the operator to perform manual actions identified in the operating procedures associated with design basis accident events are designated as Type A. These variables are restricted to preplanned actions for design basis accident events.

- Variables needed to assess that the plant critical safety functions are accomplished or maintained, as identified in the plant safety analysis and other evaluations, are designated as Type B.

- Variables used to monitor for the gross breach or the potential for gross breach of the fuel cladding, the reactor coolant pressure boundary, or the containment are designated as Type C.

- Variables needed to assess the operation of individual safety-related systems are designated as Type D.

- Variables used in determining the magnitude of the postulated releases and continually assessing releases of radioactive materials are designated as Type E.

- Variables that provide information to manually actuate and to monitor the performance of nonsafety-related systems to prevent unnecessary actuation of safety-related systems following plant events are designated as Type F.

The six classifications of variables are not mutually exclusive. When a variable is included in one or more of the six classifications, the equipment monitoring this variable meets the requirements of the highest category identified.

Three categories of design and qualification criteria are used. This classification is made to identify the importance of the information and to specify the requirements placed on the accident monitoring instrumentation. Category 1 instrumentation has the highest performance requirements and is used for information that cannot be lost. Category 2 and Category 3 instruments are of lesser importance in determining the state of the plant and do not require the same level of operational assurance.

The primary differences between category requirements are in qualification, application of single failure, power supply, and display requirements. Category 1 requires seismic and environmental qualification, the application of a single-failure criterion, use of emergency power, and an immediately accessible display. Category 2 requires environmental and seismic qualification commensurate with the required function. It may require emergency power, but does not require the single failure criterion or an immediately accessible display. Category 2 requires a rigorous performance verification for a single instrument channel. Category 3, which is high quality commercial grade, does not require qualification, single failure criterion, emergency power, or an immediately accessible display.

Table 7.5-1 summarizes the following information for each variable identified:

- Instrument range or status
- Type and category
- Environmental qualification
- Seismic qualification
- Number of required channels
- Power supply
- Qualified data processing system (QDPS) indication

7.5.2.1 Variable Types

Accident monitoring variables and information display channels are those that enable the control room operating staff to perform the functions defined by the Types A, B, C, D, E, and F classifications.

Type A

Type A variables provide the primary information to permit the control room operating staff to:

- Perform the diagnosis in the AP1000 emergency operating instructions

- Take the specified, preplanned, manually-controlled actions, for which automatic controls are not provided, and that are required for safety-related systems to mitigate design basis accidents

Type A variables are restricted to preplanned actions for design basis accidents. Variables used for contingency actions and additional variables that might be utilized are Types B, C, D, E, and F.

Type B

Type B variables provide the control room operating staff with information to assess the process of accomplishing or maintaining critical integrity safety-related functions (that is, reactivity control, reactor coolant system integrity, reactor coolant system inventory control, reactor core cooling, heat sink maintenance, and reactor containment environment).

Type C

Type C variables provide the control room operating staff information to monitor:

- The extent to which variables that indicate the potential for causing a gross breach of a fission product barrier have exceeded the design basis values

- The in-core fuel cladding, the reactor coolant pressure boundary, or the primary reactor containment that may have been subject to gross breach

These variables include those required to initiate the early phases of an emergency plan. Excluded are those associated with monitoring of radiological release from the plant that are included in Type E.

Type C variables used to monitor the potential for breach of a fission product barrier have an extended range. The extended range is chosen to minimize the probability of instrument saturation even if conditions exceed those predicted by the safety analysis.

Although variables selected to fulfill Type C functions may rapidly approach the values that indicate an actual gross failure, it is the final steady-state value reached that is important. Therefore, a high degree of accuracy and a rapid response time are not necessary for Type C instrument channels.

Type D

Type D variables provide the control room operating staff with sufficient information to:

- Monitor the performance of plant safety-related systems used for mitigating the consequences of an accident and subsequent plant recovery to attain a safe shutdown condition, including verification of the automatic actuation of safety-related systems

- Take specified, preplanned, manually controlled actions using safety-related systems for establishing and maintaining a safe shutdown condition

Type E

Type E variables provide the control room operating staff with information to:

- Monitor the plant areas where access may be required to service equipment necessary to monitor or mitigate the consequences of an accident
- Estimate the magnitude of release of radioactive material through identified pathways and continually assess such releases
- Monitor radiation levels and radioactivity in the environment surrounding the plant
- Monitor the habitability of the main control room

Type F

Type F variables provide the information that allows the control room operating staff to:

- Take specified, preplanned, manually controlled actions using nonsafety-related systems to prevent the unnecessary actuation of safety-related systems
- Monitor the performance of plant nonsafety-related systems used for mitigating the consequences of an accident and subsequent plant recovery to establish shutdown conditions, including verification of the automatic actuation of nonsafety-related systems
- Operate other nonsafety-related systems normally used for plant cooldown and to maintain plant shutdown conditions

7.5.2.2 Variable Categories

The qualification requirements of the Types A, B, C, D, E, and F accident monitoring instrumentation are subdivided into three categories. Descriptions of the three categories are given below. Table 7.5-2 summarizes the selection criteria for Types A, B, C, D, E, and F variables into each of the three categories. Table 7.5-3 summarizes the design and qualification requirements of the three designated categories.

7.5.2.2.1 Category 1

Selection Criteria for Category 1

The selection criteria for Category 1 variables are subdivided according to the variable type. For Type A, those primary variables used for diagnosis or providing information for necessary operator action are designated as Category 1. For Type B, those primary variables used for monitoring the process of accomplishing or maintaining critical safety functions are designated Category 1. For Type C, those primary variables used for monitoring the potential for breach of a fission product barrier are designated as Category 1. There are no Types D, E, or F Category 1 variables.

Qualification Criteria for Category 1

The Category 1 instrumentation is seismically and environmentally qualified as described in Sections 3.10 and 3.11. Instrumentation continues to read within the required accuracy following, but not necessarily during, a seismic event.

Each instrumentation channel is qualified from the sensor up to, and including, the display. Subsection 7.5.2.2.4 details the extended range instrumentation qualification.

Design Criteria for Category 1

The following design criteria apply to Category 1:

- No single failure (within either the accident monitoring instrumentation, its auxiliary supporting features, or its power sources), concurrent with the failures that are a cause of or result from a specific accident, prevents the control room operating staff from receiving the required information. Where failure of one accident monitoring channel results in information ambiguity (that is, the redundant displays disagree), additional information is provided to allow the control room operating staff to analyze the actual conditions in the plant. This is accomplished by providing additional independent channels of information of the same variable (an identical channel), or by providing independent channels which monitor different variables which bear known relationships to the channels (a diverse channel(s)). Redundant or diverse channels are electrically independent and physically separated from each other and from equipment not classified as safety-related.

  If ambiguity does not result from failure of the channel, then a redundant or diverse channel is not provided.

- The instrumentation is energized from the uninterruptible power supply inverter subsystem from the Class 1E dc system.

- Servicing, testing, and calibration programs are specified to maintain the capability of the monitoring instrumentation. For those instruments where the required interval between testing is less than the normal time interval between shutdowns, a capability for testing during power operation is provided.

- The design provides administrative control of the access for removing channels from service.

- The design provides administrative control of the access to setpoint adjustments, module calibration adjustments, and test points.

- The monitoring instrumentation design minimizes the development of conditions that cause displays to give anomalous indications that are potentially confusing to the control room operating staff.

- The instrumentation is designed to promote the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.

- To the extent practicable, monitoring instrumentation inputs are from sensors that directly measure the desired variables. An indirect measurement is made only when it is shown by analysis to provide unambiguous information.

- Periodic checking, testing, calibration, and calibration verification is performed.

- The range selected for the instrumentation encompasses the expected operating range of the monitored variable.

Information Processing and Display Interface Criteria for Category 1

The following interface criteria are implemented in the processing and displaying of the information:

- The control room operating staff has immediate access to the information from redundant or diverse channels in familiar units of measure. For example, degrees are used, not volts, for temperature readings. Where two or more instruments are needed to cover a particular range, overlapping instrument spans are provided.

- Continuous recording of these channels is provided following an accident until continuous recording of such information is not necessary. The term continuous recording does not exclude the use of discrete time sample data storage systems. This recording is available when required and does not need to be immediately accessible. The recording function is provided by the non-Class 1E data display and processing system.

7.5.2.2.2 Category 2

Selection Criteria for Category 2

The selection criteria for Category 2 variables are subdivided according to the variable type. For Types A, B, and C, some variables that provide backup information are designated Category 2. For Type D, those primary variables that are used for monitoring the performance of safety systems are designated as Category 2. For Type E, those primary parameters monitored for use in determining the magnitude of the release of radioactive materials and for continuously assessing such releases are designated as Category 2. For Type F, those primary parameters monitored for use in implementing preplanned actions using nonsafety-related systems or for monitoring the status of nonsafety-related system operation are designated as Category 2.

Qualification Criteria for Category 2

Category 2 instrumentation is qualified from the sensor up to, and including, the channel isolation device for the environment in which it operates to serve its intended function.

Design Criteria for Category 2

The following design criteria apply to Category 2:

- Category 2 instrumentation that is required for operation of a safety-related component is energized from the Class 1E dc uninterruptible power supply system. Otherwise, the instrumentation is energized from the non-Class 1E dc uninterruptible power system.

- The out-of-service interval is based on the technical specification requirements on out-of-service for the system the instrument serves where applicable.

- Servicing, testing, and calibration programs are implemented to maintain the capability of the monitoring instrumentation. For those instruments where the required interval between testing is less than the time interval between shutdowns, a capability for testing during power operation is provided.

- The design provides administrative control of the access for removing channels from service.

- The design provides administrative control of the access to setpoint adjustments, module calibration adjustments, and test points.

- The monitoring instrumentation design minimizes the potential for the development of conditions that cause displays to give anomalous indications that are potentially confusing to the control room operating staff.

- The instrumentation is designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.

- To the extent practicable, monitoring instrumentation inputs are from sensors that directly measure the desired variables. An indirect measurement is made only when it can be shown by analysis to provide unambiguous information.

- Periodic checking, testing, calibration, and calibration verification is performed.

- The range selected for the instrumentation encompasses the expected operating range of the monitored variable.

Information Processing and Display Interface Criteria for Category 2

The instrumentation signal is processed for display on demand. Recording requirements are determined on a case-by-case basis.

7.5.2.2.3 Category 3

Selection Criteria for Category 3

The selection criteria for Category 3 variables are subdivided according to the variable type. Types B, C, D, E, and F variables which provide backup information are designated as Category 3.

Qualification Criteria for Category 3

The instrumentation is high quality, commercial grade which is not required to provide information when exposed to a post-accident adverse environment.

Design Criteria for Category 3

The following design criteria apply to Category 3:

- Servicing, testing, and calibration programs are implemented to maintain the capability of the monitoring instrumentation. For those instruments where the required interval between testing is less than the normal time interval between plant shutdowns, a capability for testing during power operation is provided.

- The design provides administrative control of the access for removing channels from service.

- The design provides administrative control of the access to setpoint adjustments, module calibration adjustments, and test points.

- The monitoring instrumentation design minimizes the potential for the development of conditions that cause displays to give anomalous indications that are potentially confusing to the control room operating staff.

- The instrumentation is designed to facilitate the recognition, location, replacement, repair, or adjustment of malfunctioning components or modules.

- To the extent practicable, monitoring instrumentation inputs are from sensors that directly measure the desired variables. An indirect measurement is made only when it can be shown by analysis to provide unambiguous information.

Information Processing and Display Interface Criteria for Category 3

The instrumentation signal is processed for display on demand. Recording requirements are determined on a case-by-case basis.

7.5.2.2.4 Extended Range Instrumentation Qualification Criteria

The qualification environment for extended range instrumentation is based on the design basis accident events. The qualification value of the monitored variable is equal to the maximum range for the variable. The monitored variable is assumed to approach this peak by extrapolating the

most severe initial ramp associated with the design basis accident events. The decay is considered proportional to the decay for this variable associated with the design basis accidents. No additional qualification margin is added to the extended range variable. Since extended variable ranges are nonmechanistically determined, extension of associated parameter levels is not justifiable and is, therefore, not implemented. For example, a sensor measuring containment pressure is qualified for the measured process variable range (that is, four times design pressure for steel containments), but the corresponding ambient temperature is not mechanistically linked to that pressure. Rather, the ambient temperature value is the bounding value for design basis accident events analyzed in Chapter 15. The extended range instrument provides information if conditions degrade beyond those postulated in the safety analysis.

7.5.3 Description of Variables

7.5.3.1 Type A Variables

Type A variables provide primary information to permit the control room operating staff to:

- Perform the diagnosis in the AP1000 emergency operating procedures.
- Take specified preplanned, manually-controlled actions, for which automatic controls are not provided, and that are required for safety-related systems to mitigate design basis accidents.

There are no specific preplanned, manually-controlled actions for safety-related systems to mitigate design basis events in the AP1000 design. Therefore, as reflected in Table 7.5-4, there are no Type A variables.

7.5.3.2 Type B Variables

Type B variables provide information to the control room operating staff to assess the process of accomplishing or maintaining critical safety functions, including the following:

- Reactivity control
- Reactor coolant system integrity
- Reactor coolant system inventory control
- Reactor core cooling
- Heat sink maintenance
- Containment environment.

Variables which provide the most direct indication (primary variable) to assess each of the six critical safety functions are designated as Category 1. Backup variables are designated as Category 2 or Category 3. These variables are listed in Table 7.5-5.

7.5.3.3 Type C Variables

Type C variables provide the control room operating staff with information to monitor the potential for breach or the actual gross breach of:

- Incore fuel cladding
- Reactor coolant system boundary
- Containment boundary.

Variables associated with monitoring radiological release from the plant are included in Type E.

Those Type C variables that provide the most direct measure of the potential for breach of one of the three fission product boundaries are designated as Category 1. Backup information that indicates potential for breach or actual breach is designated as Category 2 or Category 3. These variables are listed in Table 7.5-6.

7.5.3.4 Type D Variables

Type D variables provide sufficient information to the control room operating staff to:

- Monitor the performance of plant safety-related systems used for mitigating the consequences of an accident and subsequent plant recovery to attain a safe shutdown condition, including verification of the automatic actuation of safety-related systems

- Take specified, preplanned, manually controlled actions using safety-related systems used for establishing and maintaining a safe shutdown condition

Primary Type D variables are designated as Category 2. Backup information is designated as Category 3. These variables are listed in Table 7.5-7.

7.5.3.5 Type E Variables

Type E variables provide the control room operating staff with information to:

- Monitor the plant areas where access may be required to service equipment to monitor or mitigate the consequences of an accident

- Estimate the magnitude of release of radioactive materials through identified pathways

- Monitor radiation levels and radioactivity in the environment surrounding the plant

- Monitor the habitability of the main control room

Primary Type E variables are designated as Category 2. Backup variables are designated as Category 3. These variables are listed in Table 7.5-8.

7.5.3.6 Type F Variables

Type F variables provide the control room operating staff with information to:

- Take preplanned manual actions using nonsafety-related systems to prevent unnecessary actuation of the safety-related systems
- Monitor the performance of the nonsafety-related systems used to mitigate the consequences of an accident
- Operate other nonsafety-related systems normally used for plant cooldown and to maintain plant shutdown conditions

Primary Type F variables are designated as Category 2. Backup variables are designated as Category 3. These variables are listed in Table 7.5-9.

7.5.4 Processing and Display Equipment

The AP1000 processing and display function is performed by equipment which is part of the protection and safety monitoring system, plant control system, and the data display and processing system. A description of each of these processing systems is provided in Section 7.1.

The protection and safety monitoring system provides signal conditioning, communications, and display functions for Category 1 variables and for Category 2 variables that are energized from the Class 1E dc uninterruptible power supply system. The plant control system and the data display and processing system provides signal conditioning, communications and display functions for Category 3 variables and for Category 2 variables that are energized from the non-Class 1E dc uninterruptible power system. The data display and processing system also provides an alternate display of the variables which are displayed by the protection and safety monitoring system. Electrical separation of the data display and processing system and the protection and safety monitoring system is maintained through the use of isolation devices in the interconnections connecting the two systems, as discussed in subsection 7.1.2.10. The portion of the protection and safety monitoring system which is dedicated to providing the safety-related display function is referred to as the qualified data processing subsystems and are discussed in subsection 7.1.2.5.

The qualified data processing subsystems are divided into two separate electrical divisions. Each of the two electrical divisions is connected to a Class 1E dc uninterruptible power system with sufficient battery capacity to provide necessary electrical power for at least 72 hours. If all ac power sources are lost for a period of time that exceeds 72 hours, the power supply system will be energized from the ancillary diesel generator or from ac power sources which are brought to the site from other locations. See Section 8.3.

Instrumentation associated with primary variables that are energized from the Class 1E dc uninterruptible power supply system are powered from one of the two electrical divisions with 72 hour battery capacity. Instrumentation associated with other variables that are energized from the Class 1E dc uninterruptible power supply system are powered from one of four electrical divisions with 24 hour battery capacity. If a variable exists only to provide a backup to a primary variable, it may be powered by an electrical division with a 24 hour battery capacity. In such

cases, provisions are provided to enable this variable to be powered by an alternate source if it is needed to resolve a discrepancy between two primary variables in the event that all ac power sources are lost for a period in excess of 24 hours.

Class 1E position indication signals for valves and electrical breakers may be powered by an electrical division with 24 hour battery capacity. This is necessary to make full use of all four Class 1E electrical divisions to enhance fire separation criteria. The power associated with the actuation signal for each of these valves or electrical breakers is provided by an electrical division with 24 hour battery capacity, so there is no need to provide position indication beyond this period. The operator will verify that the valves or electrical breakers have achieved the proper position for long-term stable plant operation before position indication is lost. Once the position indication is lost, there is no need for further monitoring since the operator does not have any remote capability for changing the position of these components.

Electrically operated valves, which have the electrical power removed to meet the single failure criterion, are provided with redundant valve position sensors. Each of the two position sensors is powered from a different non-Class 1E power source.

7.5.5 Combined License Information

This section has no requirement for information to be provided in support of the Combined License application.

Table 7.5-1 (Sheet 1 of 12)

POST-ACCIDENT MONITORING SYSTEM

Variable	Range/ Status	Type/ Category	Qualification		Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
			Environmental	Seismic				
RCS pressure	0-3300 psig	B1, B2, D2, C1, F2	Harsh	Yes	3 (Note 4)	1E	Yes	Located inside containment
RCS T_H (Wide Range)	50-700°F	B1, B2, D2, F2	Harsh	Yes	2	1E	Yes	Diverse Measurement: Core exit temperature
RCS T_C (Wide Range)	50-700°F	B1, B2, D2, F2	Harsh	Yes	3 (Note 4)	1E	Yes	
Steam generator water level (wide range)	0-100% of span	D2, F3	Harsh	Yes	1/steam generator	1E	Yes	
Steam generator water level (narrow range)	0-100% of span	D2, F2	Harsh	Yes	1/steam generator	1E	Yes	
Pressurizer level	0-100% of span	B1, D2, F2	Harsh	Yes	3 (Note 4)	1E	Yes	
Pressurizer reference leg temperature	50-420°F	B1, D2	Harsh	Yes	3 (Note 4)	1E	Yes	
Neutron flux	10^{-6}-200% power	B1	Harsh	Yes	3 (Note 4)	1E	Yes	
Control rod position	0-267 steps	B3, D3	None	None	1/control rod	Non-1E	No	
Containment water level	El. 72 ft. to 110 ft. in discrete steps	B1, C1, F2	Harsh	Yes	3 (Note 4)	1E	Yes	

Table 7.5-1 (Sheet 2 of 12)

POST-ACCIDENT MONITORING SYSTEM

Variable	Range/ Status	Type/ Category	Qualification: Environmental	Qualification: Seismic	Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
Core exit temperature	200-2300°F	B1, C1, F2	Harsh	Yes	3/quadrant	1E	Yes	
PRHR HX inlet temperature	50-650°F	D3	None	None	1	Non-1E	No	Primary indication is RCS T_H
PRHR HX outlet temperature	50-500°F	B1, D2	Harsh	Yes	1	1E	Yes	Diverse variable to PRHR flow
PRHR flow	700-3000 gpm	B1, D2, F2	Harsh	Yes	2	1E	Yes	Diverse measure-ment: PRHR outlet temperature
IRWST water level	0-100% of span	B1, D2, F2	Harsh	Yes	3 (Note 4)	1E	Yes	
RCS subcooling (Note 6)	200°F Sub-cooling to 35°F super heat	B1, F2	Harsh	Yes	2	1E	Yes	Diverse measure-ment: Core exit temperature & wide range RCS pressure
Passive containment cooling water flow	0-150 gpm	B1, D2	Mild	Yes	1 (Note 1)	1E	Yes	
PCS storage tank water level	5-100% of tank height	B1, D2	Mild	Yes	2	1E	Yes	Diverse measure-ment: PCS flow
IRWST surface temperature	50-300°F	D3	None	None	1	Non-1E	No	
IRWST bottom temperature	50-300°F	D3	None	None	1	Non-1E	No	
Steam line pressure	0-1200 psig	F2	Harsh/ Mild (Note 8)	Yes	1/steam generator (Note 11)	1E	No	

Table 7.5-1 (Sheet 3 of 12)

POST-ACCIDENT MONITORING SYSTEM

Variable	Range/ Status	Type/ Category	Qualification		Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
			Environmental	Seismic				
Startup feedwater flow	0-1000 gpm	F2	Mild	Yes	1/steam generator (Note 11)	1E	No	
Startup feedwater control valve status	Open/ Closed	D2, F3	Harsh	None	1/valve	Non-1E	No	
Containment pressure	-5 to 10 psig	B1, C2, D2, F2	Harsh	Yes	3 (Note 4)	1E	Yes	
Containment pressure (extended range)	0 to 240 psig	C1	Harsh	Yes	3 (Note 4)	1E	Yes	
Containment area radiation (high range)	10^0-10^7 R	C1, E2, F2	Harsh	Yes	3 (Note 4)	1E	Yes	
Reactor vessel hot leg water level	0-100% of span	B2, B3	Harsh	Yes	1	1E	Yes	Two instruments are provided
Plant vent radiation level	(Note 3)	C2, E2	Mild	None	1	Non-1E	No	
Remotely operated containment isolation valve status	Open/ Closed	B1, D2	Harsh/mild	Yes	1/valve (Note 7)	1E	Yes	Separate divisions on series valves
Boundary environs radiation	N/A	C3, E3	None	None	N/A	Non-1E	No	Site specific
Hydrogen concentration	0-20%	C3	None	None	1	Non-1E	No	Three instruments are provided

Table 7.5-1 (Sheet 4 of 12)

POST-ACCIDENT MONITORING SYSTEM

Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
Class 1E dc switchboard voltages	0-150 Vdc	D2	Mild	Yes	1/switchboard	1E	Yes	
Diesel generator status	On/Off	F3	None	None	1/diesel generator	Non-1E	No	
Diesel generator load	0-6000 kW	F3	None	None	1/diesel generator	Non-1E	No	
Voltage for diesel-backed buses	0-8600V	F3	None	None	3/bus	Non-1E	No	
Power supply to diesel-backed buses	On/Off	F3	None	None	1/supply source/bus	Non-1E	No	
RCP bearing water temperature	70-450°F	F3	None	Yes	1/RCP (Note 10)	1E	No	
RCP breaker status	Open/ Closed	D2, F3	Mild	Yes	1/breaker (Note 11)	1E	No	
Reactor trip breaker status	Open/ Closed	D2	Mild	Yes	1/breaker (Note 11)	1E	No	
MCR air storage bottle pressure	0-5000 psig	D2	Mild	None	1	Non-1E	No	Two instruments are provided
Turbine stop valve status	Open/ Closed	D2	None (Note 12)	None	1/valve	Non-1E	No	
Turbine control valve status	Open/ Closed	D2	None (Note 12)	None	1/valve	Non-1E	No	
Pressurizer pressure	1700-2500 psig	B1, D2	Harsh	Yes	3 (Note 4)	1E	Yes	
Pressurizer safety valve status	Open/ Closed	D2	Harsh	None	1/valve	Non-1E	No	
Pressurizer heater power (current)	0-800 amps	F3	None	None	1/group	Non-1E	No	
Steam generator PORV status	Open/ Closed	D2, F3	Harsh	None	1/valve	Non-1E	No	

Table 7.5-1 (Sheet 5 of 12)

POST-ACCIDENT MONITORING SYSTEM

Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
Steam generator PORV block valve status	Open/ Closed	D2, F3	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Steam generator safety valve status	Open/ Closed	D2	Harsh	None	1/valve	Non-1E	No	
Main feedwater isolation valve status	Open/ Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Main feedwater flow	0-9x10^6 lb/hr	F3	None	None	1/feedline	Non-1E	No	
Main feedwater control valve status	Open/ Closed	D2	Harsh	None	1/valve	Non-1E	No	
Steam generator blowdown isolation valve status	Open/ Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Steam flow	0-9x10^6 lb/hr	F3	None	None	1/steam generator	Non-1E	No	
Main steam line isolation valve status	Open/ Closed	D2, F3	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Main steam line isolation bypass valve status	Open/ Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Main feedwater pump status	On/Off	D2, F3	Mild	None	1/pump	Non-1E	No	
Main to startup feedwater crossover valve status	Open/ Closed	D2, F3	Mild	None	1/valve	Non-1E	No	
Startup feed-water pump status	On/Off	F3	None	None	1/pump	Non-1E	No	
Circulating water pump status	On/Off	F3	None	None	1/pump	Non-1E	No	
Condenser backpressure	0-1 atm	F3	None	None	1	Non-1E	No	

Table 7.5-1 (Sheet 6 of 12)

POST-ACCIDENT MONITORING SYSTEM

Variable	Range/ Status	Type/ Category	Qualification: Environmental	Qualification: Seismic	Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
Startup feedwater Isolation valve status	Open/ Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
Condenser steam dump valve status	Open/ Closed	D2, F3	Mild	None	1/valve	Non-1E	No	
Condensate storage tank water level	0-100% of span	F3	None	None	1	Non-1E	No	
PCS water storage tank isolation valve status (Non-MOV)	Open/ Closed	D2	Mild	None	1/valve	Non-1E	No	
PCS water storage tank series isolation valve status (MOV)	Open/ Closed	D2	Mild	Yes	1/valve (Note 7)	1E	Yes	
Containment temperature	32-400°F	D2, F3	Harsh	None	1	Non-1E	No	
CCS surge tank level	0-100% of span	F3	None	None	1	Non-1E	No	
CCS flow	0-15,000 gpm	F3	None	None	1	Non-1E	No	
CCS pump status	On/Off	F3	None	None	1/pump	Non-1E	No	
CCS flow to RNS valve status	Open/ Closed	F3	None	None	1/valve	Non-1E	No	
CCS flow to RCPs valve status	Open/ Closed	F3	None	None	1/valve	Non-1E	No	
CCS pump inlet temperature	50-200°F	F3	None	None	1	Non-1E	No	
CCS heat exchanger outlet temperature	50-130°F	F3	None	None	1	Non-1E	No	
Containment fan cooler status	On/Off	F3	None	None	1/fan	Non-1E	No	

Table 7.5-1 (Sheet 7 of 12)

POST-ACCIDENT MONITORING SYSTEM

Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
Water-cooled chiller status	On/Off	F3	None	None	1/chiller	Non-1E	No	
Water-cooled chilled water pump status	On/Off	F3	None	None	1/pump	Non-1E	No	
Water-cooled chilled water valve status	Open/ Closed	F3	None	None	1/valve	Non-1E	No	
Spent fuel pool pump flow	0-1500 gpm	F3	None	None	1/pump	Non-1E	No	
Spent fuel pool temperature	50-250°F	F3	None	None	1	Non-1E	No	
Spent fuel pool water level	0-100% of span	D2, F3	Mild	Yes	3 (Note 4)	1E	Yes	
CMT discharge isolation valve status	Open/ Closed	D2	Harsh	No	1/valve	Non-1E	No	
CMT inlet isolation valve status	Open/ Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
CMT upper water level switch	Above/ Below	D2, F2	Harsh	Yes	1/tank	1E	Yes	
CMT lower water level switch	Above/ Below	D2, F2	Harsh	Yes	1/tank	1E	Yes	
IRWST injection isolation valve (Squib)	Open/ Closed	D2	Harsh	None	1/valve	Non-1E	No	
IRWST line isolation valve status (MOV)	Open/ Closed	D3	None	None	1/valve	Non-1E	No	
ADS: first, second and third stage valve status	Open/ Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	

Table 7.5-1 (Sheet 8 of 12)

POST-ACCIDENT MONITORING SYSTEM

Variable	Range/ Status	Type/ Category	Qualification: Environmental	Qualification: Seismic	Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
ADS fourth stage valve status (Non-MOV)	Open/ Closed	D2	Harsh	None	1/valve	Non-1E	No	
ADS fourth stage valve status (MOV)	Open/ Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
PRHR HX inlet isolation valve status	Open/ Closed	D2	Harsh	Yes	1 (Note 7)	1E	Yes	
PRHR HX control valve status	Position	D2	Harsh	None	1/valve	Non-1E	No	
IRWST gutter bypass isolation valve status	Open/ Closed	D2	Harsh	None	1/valve	Non-1E	No	
Accumulator pressure	100-800 psig	D2	Harsh	None	1/tank	Non-1E	No	
Accumulator isolation valve status	Open/ Closed	D3	None	None	1/valve	Non-1E	No	
Accumulator vent valve status	Open/ Closed	F3	None	None	1/valve	Non-1E	No	
Pressurizer spray valve status	Open/ Closed	F3	None	None	1/valve	Non-1E	No	
Auxiliary spray line isolation valve status	Open/ Closed	D2, F3	Harsh	None	1	Non-1E	No	
Purification stop valve status	Open/ Closed	D2	Harsh	Yes	1/valve (Note 11)	1E	No	
Containment recirculation isolation valve status (Non-MOV)	Open/ Closed	D2	Harsh	None	1/valve	Non-1E	No	
Containment recirculation isolation valve status (MOV)	Open/ Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	

Table 7.5-1 (Sheet 9 of 12)

POST-ACCIDENT MONITORING SYSTEM

Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
Purification return line stop valve status	Open/ Closed	D2	Harsh	None	1	Non-1E	No	
Boric acid tank level	0-100%	F3	None	None	1	Non-1E	No	
Demineralized water isolation valve status	Open/ Closed	D2	Mild	None	1/valve	Non-1E	No	
Boric acid flow	0-300 gpm	F3	None	None	1	Non-1E	No	
Makeup blend valve status	Position	F3	None	None	1	Non-1E	No	
Makeup flow	0-300 gpm	F3	None	None	1	Non-1E	No	
Makeup pump status	On/Off	F3	None	None	1/pump	Non-1E	No	
Makeup flow control valve status	Position	F3	None	None	1	Non-1E	No	
Letdown flow	0-250 gpm	F3	None	None	1	Non-1E	No	
RNS hot leg suction isolation valve status	Open/ Closed	D2	Harsh	Yes	1/valve (Note 7)	1E	Yes	
RNS flow	0-3000 gpm	F3	None	None	1/pump	Non-1E	No	

Table 7.5-1 (Sheet 10 of 12)

POST-ACCIDENT MONITORING SYSTEM

Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
IRWST to RNS suction valve status	Open/ Closed	B1, F3	Harsh	Yes	1 (Note 7)	1E	Yes	
RNS discharge to IRWST valve status	Open/ Closed	F3	None	None	1/valve	Non-1E	No	
RNS pump status	On/Off	F3	None	None	1/pump	Non-1E	No	
Reactor vessel head vent valve status	Open/ Closed	D2	Harsh	None	1/valve	Non-1E	No	
MCR return air isolation valve status	Open/ Closed	D2, F3	Mild	None	1/valve	Non-1E	No	
MCR toilet exhaust isolation valve status	Open/ Closed	D2	Mild	None	1/valve	Non-1E	No	
MCR supply air isolation valve status	Open/ Closed	D2, F3	Mild	None	1/valve	Non-1E	No	
MCR differential pressure	-1" to +1" wg	D2	Mild	Yes	2	1E	Yes	
MCR air delivery flowrate	0-80 cfm	D2	Mild	Yes	2	1E	Yes	

Table 7.5-1 (Sheet 11 of 12)

POST-ACCIDENT MONITORING SYSTEM

Variable	Range/ Status	Type/ Category	Qualification Environmental	Qualification Seismic	Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
MCR air delivery isolation valve status	Open/ Closed	D2	Mild	None	1/valve	Non-1E	No	
Instrument air header pressure	0-125 psig	F3	None	None	1	Non-1E	No	
Service water flow	0-10,000 gpm	F3	None	None	1/pump	Non-1E	No	
Service water pump status	On/Off	F3	None	None	1/pump	Non-1E	No	
Service water pump discharge valve status	Open/ Closed	F3	None	None	1/valve	Non-1E	No	
Service water pump discharge temperature	50-150°F	F3	None	None	1/pump	Non-1E	No	
Main control room supply air radiation	Note 5	E3, F3	Mild	Yes	2 (Note 9)	1E	No	
Plant vent air flow	0-110% design flow	E2	Mild	None	1	Non-1E	No	
Turbine island vent discharge radiation level	10^{-6} - 10^{+5} μCi/cc	C2, E2	Mild	None	1	Non-1E	No	
Steam generator blowdown discharge radiation	10^{-6} - 10^{-1} μCi/cc	C2	Mild	None	1	Non-1E	No	
Steam generator blowdown brine radiation level	10^{-6} - 10^{-1} μCi/cc	C2	Mild	None	1	Non-1E	No	

Table 7.5-1 (Sheet 12 of 12)

POST-ACCIDENT MONITORING SYSTEM

Variable	Range/ Status	Type/ Category	Qualification: Environmental	Qualification: Seismic	Number of Instruments Required	Power Supply	QDPS Indication (Note 2)	Remarks
Main steam line radiation level	10^{-1} - 10^{3} μCi/cc	C2, E2	Mild	None	1/line	Non-1E	No	
Technical support center radiation	10^{-1} - 10^{4} mR/hr	E3	None	None	1	Non-1E	No	
Meteorological parameters	N/A	E3	None	None	N/A	Non-1E	No	Site specific
Primary sampling station area radiation level	10^{-1} - 10^{7} mR/hr	E3	None	None	1	Non-1E	No	

Notes:

1. Total flow measurement is obtained from the sum of four branch flow devices.
2. The same information is available in the technical support center via the monitor bus. Information available on the qualified data processing system is also available at the remote shutdown workstation.
3. Noble gas: 10^{-7} to 10^{5} μCi/cc
   Particulate: 10^{-12} to 10^{-7} μCi/cc
   Iodines: 10^{-11} to 10^{-6} μCi/cc
4. The number of instruments required after stable plant conditions is two. A third channel is available through temporary connections to resolve information ambiguity if necessary (See subsection 7.5.4).
5. Noble gas: 10^{-7} to 10^{-2} μCi/cc
   Particulate: 10^{-12} to 10^{-7} μCi/cc
   Iodines: 10^{-11} to 10^{-5} μCi/cc
6. Degree of subcooling is calculated from pressurizer pressure and RCS hot leg temperature.
7. This instrument is not required after 24 hours.
8. Two steam line pressure instruments per SG are located inside containment, and are qualified for a harsh environment. Two steam line pressure instruments per SG are located outside containment (not in MSIV compartment), and are qualified for a mild environment.
9. MCR supply air radiation monitoring is not required after MCR has been isolated.
10. This instrument is only required when non-safety power is available.
11. This instrument is not required if non-Class 1E UPS power is not available.
12. These devices are backup verification to qualified system status parameters. These devices are purchased to perform in their anticipated service environments for the plant conditions for which they must function.

Table 7.5-2

SUMMARY OF SELECTION OF CRITERIA

Type	**Category 1**	**Category 2**	**Category 3**
A	Primary variables that are used for diagnosis or providing information necessary for operator action	Variables that provide backup information	None
B	Primary variables that are used for monitoring the process of accomplishing or maintaining critical safety functions	Variables that provide backup information	Variables that provide backup information
C	Primary variables that are used for monitoring the potential for breach of a fission product barrier	Variables that provide backup information	Variables that provide backup information
D	None	Primary variables used for monitoring the performance of plant safety-related systems	Variables that provide backup information and monitor the performance of plant safety-related systems
E	None	Primary variables to be monitored in determining the magnitude of the release of radioactive materials and for continuously assessing such releases.	Variables that provide backup information in determining the magnitude of the release of radioactive materials and for continuously assessing such releases
F	None	Primary variables to be monitored to implement preplanned manual actions using nonsafety-related systems	Variables that provide backup information and for monitoring the performance of nonsafety-related systems

Table 7.5-3

SUMMARY OF QUALIFICATION, DESIGN, AND INTERFACE REQUIREMENTS

	Category 1	**Category 2**	**Category 3**
Qualification			
Environmental	Yes	Yes	No
Seismic	Yes	As appropriate (See subsection 7.5.2.2.2)	No
Design			
Single failure	Yes	No	No
Power supply	Class 1E dc battery	Class 1E dc or Non-Class 1E dc battery onsite (as appropriate, see subsection 7.5.2.2.2)	Non-Class 1E
Channel out of service	Technical Specifications	As appropriate (See subsection 7.5.2.2.2)	No specific requirement
Interface			
Minimum indication	Immediately accessible	On demand	On demand
Recording	Yes	As required (See subsection 7.5.2.2.2)	As required (See subsection 7.5.2.2.3)

Table 7.5-4

SUMMARY OF TYPE A VARIABLES

There are no Type A variables for AP1000.

Table 7.5-5

SUMMARY OF TYPE B VARIABLES

Function Monitored	**Variable**	**Type/Category**
Reactivity Control	Neutron flux	B1
	Control rod position	B3
Reactor Coolant System Integrity	RCS pressure	B1
	RCS wide range T_{hot}	B1
	RCS wide range T_{cold}	B1
	Containment water level	B1
	Containment pressure	B1
Reactor Coolant Inventory Control	Pressurizer level	B1
	Pressurizer reference leg temperature	B1
	Pressurizer pressure	B1
	Reactor vessel - hot leg water level	B3
Reactor Core Cooling	Core exit temperature	B1
	RCS subcooling	B1
	RCS wide range T_{hot}	B2
	RCS wide range T_{cold}	B2
	RCS pressure	B2
	Reactor vessel - hot leg water level	B2
Heat Sink Maintenance	IRWST water level	B1
	PRHR flow	B1
	PRHR outlet temperature	B1
	PCS storage tank water level	B1
	Passive containment cooling water flow	B1
	IRWST to RNS suction valve status	B1
Containment Environment	Containment pressure	B1
	Remotely operated containment isolation valve status	B1

Table 7.5-6

SUMMARY OF TYPE C VARIABLES

Function Monitored	Variable	Type/Category
Incore Fuel Clad	Core exit temperature	C1
RCS Boundary	RCS pressure	C1
	Containment pressure	C2
	Containment water level	C1
	Containment area high range radiation	C1
	Turbine island vent discharge radiation level	C2
	Steam generator blowdown discharge radiation level	C2
	Steam generator blowdown brine radiation level	C2
	Main steam line radiation level	C2
Containment Boundary	Containment pressure (extended range)	C1
	Plant vent radiation level	C2
	Hydrogen concentration	C3
	Boundary environs radiation	C3

Table 7.5-7 (Sheet 1 of 4)

SUMMARY OF TYPE D VARIABLES

System	Variable	Type/Category
Reactivity Control System	Reactor trip breaker status	D2
	Control rod position	D3
Pressurizer Level and Pressure Control	Pressurizer safety valve status	D2
	Pressurizer level	D2
	RCS pressure	D2
	Pressurizer pressure	D2
	Reference leg temperature	D2
RCS Loops	RCS wide range T_{hot}	D2
	RCS wide range T_{cold}	D2
	RCP breaker status	D2
Secondary Pressure and Level Control	Steam generator PORV status	D2
	Steam generator PORV block valve status	D2
	Steam generator safety valve status	D2
	Main feedwater isolation valve status	D2
	Steam generator level (wide range)	D2
	Steam generator level (narrow range)	D2
	Steam generator blowdown isolation valve status	D2

Table 7.5-7 (Sheet 2 of 4)

SUMMARY OF TYPE D VARIABLES

System	Variable	Type/Category
Secondary Pressure and Level Control (continued)	Main feedwater pump status	D2
	Main feedwater control valve status	D2
	Main steam line isolation valve status	D2
	Main steam line isolation bypass valve status	D2
Startup Feedwater	Startup feedwater control valve status	D2
	Startup feedwater isolation valve status	D2
	Main to startup feedwater crossover valve status	D2
Safeguards	Containment pressure	D2
	Accumulator pressure	D2
	Core makeup tank upper water level switch	D2
	Core makeup tank lower water level switch	D2
	IRWST/line isolation valve status (MOV)	D3
	IRWST/injection isolation valve status (Squib)	D2
	ADS first stage, second stage and third stage valve status	D2
	ADS fourth stage valve status (MOV)	D2
	ADS fourth stage valve status (non-MOV)	D2
	PRHR heat exchanger inlet isolation valve status	D3
	PRHR heat exchanger control valve status	D2
	Reactor vessel head vent valve status	D2
	CMT/discharge isolation valve status	D2
	CMT inlet isolation valve status	D2

Table 7.5-7 (Sheet 3 of 4)

SUMMARY OF TYPE D VARIABLES

System	Variable	Type/Category
Safeguards (continued)	Accumulator/isolation valve status	D3
	PRHR flow	D2
	Containment recirculation isolation valve status (MOV)	D2
	Containment recirculation isolation valve status (non-MOV)	D2
	PRHR HX inlet temperature	D3
	PRHR HX outlet temperature	D2
	IRWST surface temperature	D3
	IRWST bottom temperature	D3
	IRWST water level	D2
	IRWST gutter bypass isolation valve status	D2
	Remotely operated containment isolation valve status	D2
Chemical and Volume Control	Auxiliary spray line isolation valve status	D2
	Purification stop valve status	D2
	Purification return line stop valve status	D2
	Demineralized water isolation valve status	D2
Normal Residual Heat Removal	RNS hot leg suction isolation valve status	D2
Electric Power	Class 1E dc switchboard voltage	D2
Spent Fuel Pool	Spent fuel pool water level	D2

Table 7.5-7 (Sheet 4 of 4)

SUMMARY OF TYPE D VARIABLES

System	Variable	Type/Category
Containment Cooling	Containment temperature	D2
	PCS water storage tank series isolation valve status (MOV)	D2
	PCS water storage tank isolation valve status (non-MOV)	D2
	Passive containment cooling water flow	D2
	PCS storage tank water level	D2
HVAC System Status	MCR return air isolation damper status	D2
	MCR toilet exhaust isolation damper status	D2
	MCR supply air isolation damper status	D2
	MCR air delivery isolation valve status	D2
	MCR air storage bottle pressure	D2
	MCR differential pressure	D2
	MCR air delivery flowrate	D2
Main Steam	Turbine stop valve status	D2
	Turbine control valve status	D2
	Condenser steam dump valve status	D2

Table 7.5-8

SUMMARY OF TYPE E VARIABLES

Function Monitored	Variable	Type/Category
Containment Radiation	Containment area high range radiation level	E2
Area Radiation	Technical support center radiation level	E3
	Primary sampling station area radiation level	E3
Airborne Radioactivity Released from Plant	Turbine island vent discharge radiation level	E2
	Plant vent radiation level	E2
	Plant vent air flow	E2
	Main steam line radiation level	E2
	Boundary environs radiation	E3
	Main control room supply air radiation level	E3
Environs Radiation and Radioactivity	Site specific	E3
Meteorology	Site specific	E3
Accident Sampling	Primary coolant	E3
	Containment air	E3

Table 7.5-9 (Sheet 1 of 4)

SUMMARY OF TYPE F VARIABLES

Variable	Type/Category
Monitoring for preplanned manual nonsafety-related system actions	
RCS pressure	F2
RCS wide range T_{hot}	F2
RCS wide range T_{cold}	F2
Steam generator level (NR)	F2
Pressurizer level	F2
Containment pressure	F2
Steam line pressure	F2
Containment water level	F2
IRWST water level	F2
Startup feedwater flow	F2
Containment area high range radiation level	F2
Core exit temperature	F2
RCS subcooling	F2
PRHR flow	F2
Core makeup tank upper water level switch	F2
Core makeup tank lower water level switch	F2
Monitoring for nonsafety-related system performance	
Pressurizer heater power (current)	F3
Steam generator PORV status	F3
Steam generator PORV block valve status	F3

Table 7.5-9 (Sheet 2 of 4)

SUMMARY OF TYPE F VARIABLES

Variable	Type/Category
Startup feedwater control valve status	F3
Main feedwater flow	F3
Steam generator level (WR)	F3
Steam flow	F3
Main steam line isolation valve status	F3
Main feedwater pump status	F3
Startup feedwater pump status	F3
Condenser steam dump valve status	F3
Condensate storage tank level	F3
Pressurizer spray valve status	F3
Auxiliary spray line isolation valve status	F3
Makeup flow	F3
Makeup pump status	F3
Letdown flow	F3
Circulating water pump status	F3
Condenser backpressure	F3
Accumulator vent valve status	F3

Table 7.5-9 (Sheet 3 of 4)

SUMMARY OF TYPE F VARIABLES

Variable	Type/Category
Boric acid tank level	F3
Boric acid flow	F3
Makeup blend valve status	F3
Makeup flow control valve status	F3
RNS flow	F3
RNS pump status	F3
IRWST to RNS suction valve status	F3
RNS discharge to IRWST valve status	F3
CCS surge tank level	F3
CCS flow	F3
CCS pump status	F3
CCS flow to RNS valve status	F3
CCS flow to RCPs valve status	F3
CCS pump inlet temperature	F3
CCS heat exchanger outlet temperature	F3
Diesel generator status	F3
Diesel generator load	F3
Voltage for diesel-backed buses	F3
Power supply to diesel-backed buses	F3
RCP bearing water temperature	F3
RCP breaker status	F3
Containment fan cooler status	F3
Water-cooled chiller status	F3
Water-cooled chilled water pump status	F3
Water-cooled chilled water valve status	F3
Containment temperature	F3
Main control room supply air isolation damper status	F3
Main control room return air isolation damper status	F3
Main control room supply air radiation	F3
Service water flow	F3

Table 7.5-9 (Sheet 4 of 4)

SUMMARY OF TYPE F VARIABLES

Variable	Type/Category
Service water pump status	F3
Service water pump discharge valve status	F3
Service water pump discharge temperature	F3
Instrument air header pressure	F3
Spent fuel pool pump flow	F3
Spent fuel pool temperature	F3
Spent fuel pool water level	F3
Main to startup feedwater crossover valve status	F3

7.6 Interlock Systems Important to Safety

This section discusses interlock systems which operate to reduce the probability of occurrence of specific events or to verify the state of a safety system. These include interlocks to prevent overpressurization of low-pressure systems and interlocks to verify availability of engineered safety features.

7.6.1 Prevention of Overpressurization of Low-Pressure Systems

7.6.1.1 Description of Normal Residual Heat Removal Isolation Valve Interlocks

An interlock is provided for the normally closed, motor-operated normal residual heat removal system (RNS) inner and outer suction isolation valves. The interlock prevents the suction valves for the normal residual heat removal system from being opened by operator action unless the reactor coolant system pressure is less than a preset pressure and both the suction and discharge valves for the in-containment refueling water storage tank are in a closed position.

There are two parallel sets of two motor-operated valves in series in the normal residual heat removal system pumps suction line from the reactor coolant system hot leg. The two valves nearest the reactor coolant system are designated as the inner isolation valves. The two valves nearest the normal residual heat removal system pumps are designated as the outer isolation valves. Logic for the outer valves is similar to that provided for the inner isolation valves, except that equipment diversity is provided by virtue of the fact that the pressure transmitters used for valve interlocks on the inner valves are diverse from the pressure transmitters used for the outer valve interlocks. Typically, this diversity is achieved by procuring wide range pressure transmitters either with similar measurement principles from different vendors, or with different measurement principles (from either the same or different vendors).

Each valve is interlocked so that it cannot be opened unless the reactor coolant system pressure is below a preset pressure. This interlock prevents the valve from being opened (from the main control room or the remote shutdown workstation) when the reactor coolant system pressure is above the normal residual heat removal system design pressure.

Figure 7.2-1, sheet 18 illustrates the interlock logic which applies to these valves. The logic, shown on sheet 18 is replicated twice, once for each parallel path. A total of four pressure transmitters are used, one associated with each of the four isolation valves. This interlock logic prevents the two series isolation valves from being opened while the reactor coolant system is pressurized above a set pressure.

The valves may be closed by operator action from the main control room at any time. To prevent an inadvertent closure of these valves, no auto-closure interlock that would close the valves on high reactor coolant system pressure is included.

The normal residual heat removal system relief valves provide adequate system pressure protection for conditions after the valves have been opened. (This is discussed in subsection 5.2.2.1). Alarms are provided in the main control room and on the remote shutdown workstation to alert the operator if reactor coolant system pressure exceeds the normal residual heat removal system design pressure after the valves are opened.

7.6.1.2 Analysis of Normal Residual Heat Removal Valve Interlocks

IEEE 603-1991 and IEEE 338-1987 criteria do not apply to the normal residual heat removal isolation valve interlocks. Their function is not required during, or after, a design basis event. However, because of the possible severity of the consequences of loss of function, the requirements of IEEE 603-1991 are applied with the following comments:

- For the purpose of applying IEEE 603-1991, the protection system is the two parallel sets of two valves in series and the components of their interlock circuitry. The inner valve is powered by a separate power supply from the outer valve of each series combination.

- Online testability; IEEE 603-1991, Paragraph 5.7: The pressure interlock signals and logic are tested on line to the maximum extent possible without adversely affecting safety. This test includes the initiating signals for the interlocks from the protection and safety monitoring system cabinets.

- IEEE 603-1991, Paragraph 6.8.2: This requirement does not apply, as the setpoints are independent of mode of operation and are not changed.

7.6.2 Availability of Engineered Safety Features

7.6.2.1 Passive Residual Heat Removal Heat Exchanger Inlet Isolation Valve

The passive core cooling system passive residual heat removal heat exchanger inlet line includes a normally open motor-operated isolation valve that can be manually controlled from either the main control room or the remote shutdown workstation. The generation of the confirmatory open signal to this valve is described in subsection 7.3.1.2.7.

The use of a confirmatory open signal to this valve provides a means to automatically override bypass features that are provided to allow this isolation valve to be closed for short periods of time. As a result of the confirmatory open signal, isolation of the passive residual heat removal heat exchanger inlet line, for short periods of time during modes of plant operation when the passive residual heat removal heat exchanger is required to be operable, is acceptable.

The operation of the valve is controlled by an actuation control circuit that functions in the following manner:

- The control circuit has an automatic operation function that is normally enabled. It allows the valve to automatically open upon receipt of the confirmatory open signal, in case the valve is closed.

- The control circuit has a valve open actuation function that opens the valve when a control switch on the operator workstation is manually actuated. Once the operation is complete, the control circuit returns to automatic operation.

- The control circuit has a valve close actuation function that closes the valve when a control switch on the operator workstation is manually actuated. This function is required when

performing periodic operability testing of the passive residual heat removal heat exchanger discharge valves when the reactor is operating. Once the manual operation is complete, the control circuit returns to automatic operation.

- The control circuit has a valve maintain closed actuation function to provide an administratively controlled manual block of the automatic opening of the valve. This function allows the valve to be maintained closed if needed for leakage isolation. The maximum permissible time that a passive residual heat removal heat exchanger inlet isolation valve can be closed is specified in technical specifications. An alarm is actuated when the maintain closed function is instated.

The valve is interlocked so that:

- If the maintain closed actuation has not been manually initiated, it opens automatically on receipt of a confirmatory open signal with the control circuit in automatic control or during the manual valve close function.

- It cannot be manually closed when a confirmatory open signal is present.

During plant operation and shutdown, the passive residual heat removal heat exchanger inlet isolation valve is open. To prevent an inadvertent closure of the valve, redundant output cards are used in the protection and safety monitoring system cabinet. Power to this valve is normally locked out at power to prevent a fire-induced spurious closing.

Figure 7.2-1, sheet 17 illustrates the interlock logic which applies to the passive residual heat removal heat exchanger inlet isolation valve.

This normally open motor-operated valve has alarms, indicating valve mispositioning (with regard to their passive core cooling function). The alarm actuates in the main control room and the remote shutdown workstation.

An alarm actuates for the passive residual heat removal heat exchanger inlet isolation valve under the following conditions when the passive residual heat removal heat exchanger is required:

- Sensors on the motor operator for the valve indicate when the valve is not fully open.

- Redundant sensors on the valve stem indicate when the valve is not fully open.

7.6.2.2 Core Makeup Tank Cold Leg Balance Line Isolation Valves

Each core makeup tank has a cold leg balance line which is provided with a normally open, motor-operated, isolation valve. The balance line isolation valves, for each core makeup tank, may be manually controlled from either the main control room or the remote shutdown workstation. The generation of the confirmatory open signal to these valves is described in subsection 7.3.1.2.3.

A confirmatory open signal to these valves automatically overrides any bypass features that are provided to allow the balance line isolation valve to be closed for short periods of time. As a result

of the confirmatory open signal, isolation of the core makeup tank cold leg balance line to permit inservice testing of the core makeup tank discharge valves, is acceptable.

The operation of each valve is controlled by an actuation control circuit that functions in the following manner:

- The control circuit has an automatic operation function that automatically opens the valve upon receipt of the confirmatory open signal, in case the valve is closed.

- The control circuit has a valve open actuation function that opens the valve when a control switch on the operator workstation is manually actuated. Once the operation is complete, the control circuit returns to automatic operation.

- The control circuit has a valve close actuation function that closes the valve when a control switch on the operator workstation is manually actuated. This function is provided for performing periodic operability tests of the core makeup tank discharge valves when the reactor is operating. Once the manual operation is complete, the control circuit returns to automatic operation.

- The control circuit has a valve maintain closed actuation function to provide an administratively controlled manual block of the automatic opening of the valve when the pressurizer level is greater than the P-12 interlock. This function allows the valve to be maintained closed if needed for leakage isolation. The maximum permissible time that a core makeup tank cold leg balance line isolation valve can be closed is specified in technical specifications. An alarm is actuated when the maintain closed function is instated.

Each valve is interlocked so that:

- If the maintain closed actuation has not been manually initiated, it opens automatically on receipt of a confirmatory open signal with the control circuit in automatic control or during the manual valve close function.

- It opens automatically whenever the pressurizer water level increases above the P-12 interlock, and the control circuit is in automatic control.

- It cannot be manually closed when a confirmatory open signal is present.

During power and shutdown operations, the core makeup tank cold leg balance line isolation valve remains open. To prevent an inadvertent closure of the valve, redundant output cards are used in the protection and safety monitoring system cabinet. As a result, it is not necessary to lock out control circuit power.

Figure 7.2-1, sheet 17 illustrates the interlock logic which applies to the cold leg balance line isolation valves on each of the two core makeup tanks. The logic shown on sheet 17 is replicated for each core makeup tank.

These normally open motor-operated valves have alarms, indicating valve mispositioning (with regard to their passive core cooling function). The alarms actuate in the main control room and the remote shutdown workstation.

An alarm actuates for a core makeup tank cold leg balance line isolation valve under the following conditions when the core makeup tank is required to be operable:

- Sensors on the motor operator for the valve indicate when the valve is not fully open.
- Redundant sensors on the valve stem indicate when the valve is not fully open.

7.6.2.3 Interlocks for the Accumulator Isolation Valve and IRWST Discharge Valve

The accumulator isolation and in-containment refueling water storage tank injection isolation valves are safety-related in order to retain their pressure boundary and remain in their open position. The accumulator isolation and in-containment refueling water storage tank injection valve operators are nonsafety-related since the valves are not required to change position to mitigate an accident. The DCD Chapter 15 safety analyses assume that these valves are not subject to valve mispositioning (prior to an accident) or spurious closure (during an accident). Valve mispositioning and spurious closure are prevented by the following:

- The Technical Specifications, Section 16.1, require these valves to be open and power locked out whenever these injection paths are required to be available. The accumulators are required to be available when the reactor coolant system pressure is above 1000 psia. Both in-containment refueling water storage tank injection lines are required to be available in Modes 1, 2, 3, and 4. One in-containment refueling water storage tank injection line is required to be available in Mode 5 and in Mode 6 with the reactor upper internals not removed and the refueling cavity not filled.
- The Technical Specifications, Section 16.1, require verification that the motor-operated valves are open every 12 hours. They also require verification that power is removed every 31 days.
- With power locked out, redundant (nonsafety-related) valve position indication is provided in the main control room and remote shutdown workstation. Valve position indication and alarm are provided to alert the operator if these valves are mispositioned. These indications are powered by different nonsafety-related power supplies.

In addition, the valves have a confirmatory open signal during an accident (safeguards actuation signal for accumulator motor-operated valves and automatic depressurization system stage 4 signal for in-containment refueling water storage tank motor-operated valves). The valves also have an automatic open signal when their close permissives (P-11 for accumulator motor-operated valves and P-12 for in-containment refueling water storage tank motor-operated valves) clear during plant startup. The confirmatory open and the automatic open control signals are provided to the valve operator by the nonsafety-related plant control system.

7.6.3 Combined License Information

This section has no requirement for information to be provided in support of the Combined License application.

7.7 Control and Instrumentation Systems

The function of the AP1000 control systems is to establish and maintain the plant operating conditions within prescribed limits. The control system improves plant safety by minimizing the number of situations for which some protective response is initiated and relieves the operator from routine tasks.

The AP1000 control systems share a common hardware design and implementation philosophy. They are also functionally integrated to enhance responsiveness during plant transients. Specific design requirements are imposed that limit the impact of individual equipment failures. (See subsection 7.1.3).

The control systems regulate the operating conditions in the plant automatically in response to changing plant conditions and changes in plant load demand. These operating conditions include the following:

Reactor Coolant System Temperature - The control systems function to maintain the reactor coolant system temperature at or near a programmed value. This value is a function of plant load or other operating conditions. Steam conditions for the turbine depend on the temperature maintained in the reactor coolant. Reactor coolant system temperature is also used for controlling core reactivity.

Nuclear Power Distribution - Operating limits include the distribution of nuclear energy production within the core as well as its average value. The axial distribution of the nuclear power is controlled within prescribed limits.

Reactor Coolant System Pressure - The reactor coolant system is pressurized to prevent significant boiling at operating temperatures. This pressure is controlled within limits that prevent reductions which expose the fuel to possible departure from nucleate boiling or from increases that would challenge the reactor coolant system design pressure.

Pressurizer Water Level - To provide a sufficient buffer for plant transients, the reactor coolant system pressurizer contains a prescribed volume of water and steam which depends on plant load and operating temperature.

Steam Generator Water Level - The steam generator water level is maintained within limits to provide adequate energy removal capability and to avoid moisture carryover.

Steam Dump (Turbine Bypass) - For fast and large transients such as load rejections, an additional thermal load (designated steam dump or turbine bypass) functions until nuclear power is reduced. This steam dump is also used to maintain hot no-load or hot low-load conditions prior to turbine loading. It provides a means for plant cooldown.

7.7.1 Description

The plant control and instrumentation systems described in this section perform the following functions:

Reactor Power Control System - The reactor power control system coordinates the responses of the various reactivity control mechanisms. The system enables daily load follow operation with a minimum of manual control by the operator. Load regulation and frequency control are compatible with the reactor power control system operation. Axial nuclear power distribution control is also performed by the reactor power control system.

Rod Control System - The rod control system, in conjunction with the reactor power control system, maintains nuclear power and reactor coolant temperature, without challenges to the protection systems, during normal operating transients.

Pressurizer Pressure Control - The pressurizer pressure control system maintains or restores the pressurizer pressure to the nominal operating value following normal operating transients. The control system reacts to avoid challenges to the protection systems during these operating transients.

Pressurizer Water Level Control - The pressurizer water level control system establishes, and maintains or restores pressurizer water level to its programmed value. The required water level is programmed as a function of reactor coolant system temperature and power generation to minimize charging and letdown requirements. No challenges to the protection system result from normal operational transients.

Feedwater Control System - The feedwater control system maintains the steam generator water level at a predetermined setpoint during steady-state operation. It also maintains the water level within operating limits during normal transient operation. The feedwater control system restores normal water level following a unit trip. The various modes of feedwater addition are automated to require a minimum of operator involvement.

Steam Dump Control - The steam dump control system reacts to prevent a reactor trip following a sudden loss of electrical load. The steam dump control system also removes stored energy and residual heat following a reactor trip so that the plant can be brought to equilibrium no-load conditions without actuation of the steam generator safety valves. The steam dump control system also provides for maintaining the plant at no-load or low-load conditions to facilitate a controlled cooldown of the plant.

Rapid Power Reduction - For large, rapid load rejections (turbine trip or grid disconnect from 50-percent power or greater) a rapid nuclear power cutback is implemented. This results in a reduction of thermal power to a level that can be handled by the steam dump system.

Defense-In-Depth Control - The plant control system provides control of systems performing defense-in-depth functions. Table 7.7-3 provides a listing of the defense-in-depth functions that are supported by the plant control system and provides a cross reference to the applicable information located in other sections of this document.

7.7.1.1 Reactor Power Control System

Automatic reactor power and power distribution control are the basic functions of the reactor power control system. They are achieved by varying the position of the control rods. Separate control rod banks are used to regulate reactor power and power distribution.

The reactor power control system enables the plant to respond to the following load change transients:

- Step load changes of plus or minus 10 percent
- Ramp load increases and decreases of 5 percent per minute
- Daily load follow operations with the following profile:
  - Power ramps from 100 percent to 50 percent in 2 hours
  - Power remains at 50 percent for 2 to 10 hours
  - Power ramps back up to 100 percent in 2 hours
  - Power remains at 100 percent for the remainder of the 24-hour cycle
- Grid frequency response (denoted load regulation) resulting in a maximum of 10-percent power change at 2 percent per minute

These capabilities are accomplished without a reactor trip or steam dump actuation. During daily load follow and load regulation transients, automatic control of axial offset is provided. The system restores coolant average temperature to a value which is within the programmed temperature band following a change in load. Manual control of either the power control rods (M banks) or the axial offset control rods (AO bank) is performed within the range of defined insertion limits.

The reactor power control system uses a different control strategy for the rods used to regulate core power (M banks) from the control strategy used to regulate axial offset (AO bank). Reactor coolant system boron concentration is adjusted by the operator to account for long-term core burnup. The adjustment also maintains the two gray M banks and both black M banks (M1 and M2) in a near fully withdrawn position, the first two moving gray M banks fully inserted, and the AO bank slightly inserted. During load follow or load regulation response transients, the power control and the axial offset control subsystems jointly function to control both core power and axial offset. The following two subsections provide a description of each control subsystem.

7.7.1.1.1 Power Control

The power control subsystem controls the reactor coolant average temperature by regulating the M control rod bank positions. The reactor coolant loop average temperatures are determined from hot and cold leg measurements in each reactor coolant loop. The average coolant temperature (T_{avg}) is computed for each loop, where:

$$T_{avg} = \frac{T_{hot} + T_{cold}}{2}$$

The error between the programmed reference temperature (based on turbine impulse chamber pressure) and the highest of the lead/lag compensated T_{avg} measured temperatures from each of the reactor coolant loops constitutes the primary control signal. The programmed coolant temperature increases linearly with turbine load from the zero-power to the full-power condition.

The temperature input signals for the power control subsystem are fed from protection channels via isolation devices and the signal selector function.

An additional control input signal is derived from the reactor power versus turbine load mismatch signal. This additional control input signal improves system performance by enhancing response and reducing transient peaks.

The deviation of the reactor coolant temperature from the programmed value is the basic control variable for reactor power control. A deadband is included in the power control subsystem so that no rod motion is demanded if the temperature error is within the deadband. As the temperature error becomes greater, the demanded rod speed becomes greater.

Separate reactor control deadbands are used for each mode of control (load follow, load regulation, or base load). If the plant is in a load follow or load regulation mode of operation, then the deadband is widened from that used for base load operation. This allows the core reactivity feedbacks to assist in stabilizing the plant at the conclusion of the maneuver and reduces the total control rod movement and subsequent wear on the control rods.

A different control strategy is used at low-power levels, principally when the turbine is off-line and the steam dump system is used to regulate coolant temperature. In this mode, nuclear power is controlled directly. For this mode, a nuclear power setpoint calculator allows the operator to enter a desired power level above or below the current power level along with a desired rate of change (limited to fixed predetermined maximum limits). The nuclear power setpoint calculator then supplies a changing setpoint that provides for a linear ramp change in core power at the selected rate.

7.7.1.1.2 Axial Offset Control

The axial offset control subsystem controls the core axial offset (power difference between the top and bottom halves of the core) to a value that is within the desired control range for load follow and grid frequency change transients. This is accomplished by using control rod banks separate from those used for the reactor power control described in subsection 7.7.1.1.1. Measurements of

axial offset are input into the axial offset control subsystem and then compared to an axial offset control "window." This window is calculated from measurements of compensated excore nuclear flux, along with operator inputs for the desired axial offset target value and target bandwidth and the mode of control (load follow, load regulation, or base load). The nuclear flux signals are compensated by measurements of cold leg temperature to account for the effects of moderation of the neutron flux by the reactor vessel downcomer flow. If the plant is in a load regulation mode of control, then a "smoothing" compensation is applied to both the nuclear flux and the axial offset signals. This provides a time-weighted average nuclear flux and axial offset signal input to the axial offset controller to avoid rapid temporary changes from actuating axial offset control. When the axial offset error is outside the acceptable control window, the axial offset rods are actuated until the axial offset error is back inside the control window.

To minimize the potential for interactions between the power and the axial offset rod control subsystems, the power control subsystem takes precedence. If a demand signal exists for movement of the power control rods, then the axial offset rods are blocked from moving. Only when the temperature error is within the reactor power controller deadband and the associated rod banks have stopped are the axial offset rods allowed to move.

7.7.1.2 Rod Control System

The rod control system receives rod speed and direction signals from the power control and axial offset control subsystems. The portion of the rod control system associated with the power and axial offset control subsystems each operate their own sets of control rod banks as follows:

- The power control portion operates the MA, MB, MC, MD, M1 and M2 control rod banks.
- The axial offset control portion operates the AO control rod bank.

For power control, the rod speed demand signals vary over the range of 5 to 45 inches per minute (8 to 72 steps per minute), depending on the magnitude of the input signal. Manual control is provided to move a bank in or out at a prescribed fixed speed. In the automatic mode, the rods are withdrawn (or inserted) in a predetermined sequence within the limits imposed by the control interlocks as shown in Table 7.7-1.

For axial offset control, the rod speed demand signals are set to a fixed constant speed of approximately 5 inches per minute (8 steps per minute). Manual control is provided to move a bank in or out at a prescribed fixed speed. In the automatic mode, the rods are withdrawn (or inserted) within the limits imposed by the control interlocks, as shown in Table 7.7-2.

The shutdown control rod banks are always in the fully withdrawn position during normal operation and are moved to this position at a constant speed by manual control prior to criticality. A reactor trip signal causes them to fall by gravity into the core. There are four shutdown control rod banks.

The power and axial offset control rod banks are the only rods that can be manipulated under automatic control. Each bank is divided into two or more groups to obtain smaller incremental reactivity changes per step. Each control rod assembly in a group is electrically paralleled to move simultaneously. There is individual position indication for each control rod assembly.

Power to the rod drive mechanisms is supplied by two motor-generator sets operating from two separate 480-volt, 3-phase busses. Each generator is the synchronous type, and is driven by a 200-horsepower induction motor. The ac power is distributed to the rod control system cabinets through the reactor trip switchgear.

The variable speed rod drive programmer used in the power control subsystem inserts small amounts of reactivity at low speed. This permits fine control of reactor coolant average temperature about a small temperature deadband, as well as furnishing control at high speed for transients such as load rejections. A summary of the control rod assembly sequencing characteristics is given below:

- The control rod groups within the same bank are stepped so that the relative position of the groups do not differ by more than one step.

- The control rod banks are programmed so that withdrawal of the banks is sequenced in a prescribed order. The programmed insertion sequence is the opposite of the withdrawal sequence. That is, the last control bank withdrawn is the first control bank inserted.

- The control bank withdrawals are programmed so that, when the first bank reaches a preset position, the next bank begins to move out simultaneously with the first bank. This preset position is determined by the maximum allowable overlap between banks (approximately 50 to 100 steps). This withdrawal sequence continues until the reactor reaches the desired power level. The control bank insertion sequence is the opposite of the withdrawal sequence.

- Overlap between successive control banks is adjustable between 0 to 50 percent (0 to 135 steps), with an accuracy of ±1 step.

The constant rod speed used in the axial offset control subsystem provides a slow stable control of core axial offset. This is acceptable since axial offset changes for the design basis load follow transients generally occur over several hours and rapid response is not needed. The slow response of the axial offset control system also allows the rods used by the power control subsystem to counteract the core power reactivity changes that are induced by the axial offset rods.

7.7.1.3 Control Rod Position Monitoring

Digital Rod Position - The digital rod position indication system measures the position of each control rod assembly using a detector consisting of discrete coils mounted concentric with the rod drive pressure housing. The coils are located axially along the pressure housing and magnetically sense the entry and presence of the rod drive shaft through its center line.

Demand Position System - The demand position system counts the pulses generated in the rod control system to provide a digital readout of the demanded bank position. The demanded and measured rod position signals are displayed in the main control room. An alarm is generated whenever an individual rod position signal deviates from the other rods in the bank by a preset limit. The alarm is set with appropriate allowance for instrument error and within sufficiently narrow limits to prevent exceeding core design hot channel factors.

Alarms are also generated if any shutdown rod is detected to have left its fully withdrawn position, or if any M bank control rods are detected at the bottom position, except as part of the normal insertion sequence.

7.7.1.4 Control Rod Insertion Limits

With the reactor critical, the normal indication of reactivity status in the core is the position of the control rod bank in relation to reactor power (as indicated by the ΔT power monitors). The ΔT power signal is used to calculate insertion limits for the banks. The following two alarms are provided for each bank.

- A "low" alarm and interlock alerts the operator of an approach to the rod insertion limits and acts to terminate automatic AO bank rod insertion (on reaching the AO bank "low" setpoint) or AO bank rod withdrawal (on reaching a M bank "low" setpoint). The operator terminates M bank insertion and reactor coolant system boron concentration changes by following appropriate plant procedures.

- A "low-low" alarm alerts the operator to take immediate action to restore the M bank and AO bank within the appropriate limits by terminating M bank insertion or AO bank withdrawal (for "low-low" M bank alarm), or terminating AO bank insertion (for "low-low" AO bank alarm) that were not stopped by the "low" setpoint interlock.

The purpose of the control bank rod insertion alarms and interlocks is to provide warning to the operator of excessive rod insertion and to terminate the insertion. The insertion limit maintains sufficient core reactivity shutdown margin following reactor trip. It also provides a limit on the maximum inserted rod worth in the unlikely event of a hypothetical rod ejection. Insertion limits provide confidence that acceptable nuclear peaking factors are maintained. Since the amount of shutdown reactivity required for the design shutdown margin following a reactor trip increases with increasing power, the allowable rod insertion limits are decreased (the rods must be withdrawn further) with increasing power. The insertion limits for the M banks and the AO bank are calculated from the reactor power, as measured by the ΔT power monitor, according to the following equations:

$$Z_{LL}^{M} = A + B \cdot \Delta T + C \cdot Z_{AO} + D \cdot \Delta T \cdot Z_{AO}$$

$$Z_{LL}^{AO} = E$$

where:

Z_{LL}^{M}	=	Maximum permissible insertion limit for the affected M control bank
Z_{LL}^{AO}	=	Maximum permissible insertion limit for the affected AO control bank
Z_{AO}	=	Current AO bank position

ΔT = Average signal of valid ΔT measurements

A,B,C,D,E = Constants chosen to maintain $Z_{LL} \geq$ the actual limit based on physics calculations

The control rod bank demand position (Z) for the M banks and the AO bank is compared to the respective Z_{LL} as follows:

- If $Z - Z_{LL} \leq F$, a low alarm and interlock is actuated.
- If $Z - Z_{LL} \leq G$, a low-low alarm is actuated.

Since nuclear peaking factors can be aggravated by the opposite movement of the M banks and the AO bank, the interlocks on the AO bank are different, depending on whether the M bank or the AO bank insertion limit setpoint is actuated. If an M bank insertion limit is reached, this stops AO bank withdrawal and reduces the increases in the core peaking factor. If an AO bank insertion limit is reached, this stops AO bank insertion. If the M banks are fully withdrawn, AO bank automatic insertion is blocked.

7.7.1.5 Control Rod Stops

Rod stops are provided to prevent abnormal power conditions that could result from excessive control rod withdrawal initiated by either a control system malfunction or operator violation of administrative procedures.

7.7.1.6 Pressurizer Pressure Control System

The primary system pressure is closely regulated during operation to prevent pressure from increasing to the point where an engineered safety features actuation is required to prevent overstressing the pressure boundary; or from decreasing to a condition where engineered safety features actuation is required to prevent the possibility of departure from nucleate boiling. Fine control of pressure to the desired setpoint is accomplished by regulating the power to a bank of heaters located in the pressurizer. Large decreases in pressure are accommodated by turning on additional heater banks and by the inherent flashing from the water mass in the pressurizer, which is at saturation. Large pressure increases are controlled by actuating pressurizer spray to condense steam.

Pressurizer pressure control is designed to provide stable and accurate control of pressure to its predetermined setpoint. Automatic pressure control is available from the point at which nominal pressure is established in the startup cycle to 100-percent power. During steady-state operating conditions, the pressurizer heater output is regulated to compensate for pressurizer heat loss and a small continuous pressurizer spray. During normal transient operation, the pressure is regulated to provide adequate margin to safety systems actuation or reactor trip. The pressurizer pressure control system is designed to minimize equipment duty (such as spray nozzle thermal cycling due to spray actuation) due to load regulation operation.

Small or slowly varying changes in pressure are regulated by modulation of the variable heater control. Reset (integral) action is included to maintain pressure at its setpoint. Decreases in pressure larger than that which can be accommodated by the variable heater control results in the

actuation of the backup heaters. The backup heaters are deactivated when the variable heaters alone are capable of restoring pressure. Large increases in the pressurizer water level also result in activation of the backup heaters. The purpose of this action is to avoid the accumulation of subcooled fluid in the pressurizer, thereby allowing flashing of the pressurizer fluid to limit the pressure decrease on any subsequent outsurge.

Pressure increases too fast to be handled by reducing the variable heater output result in spray actuation. Spray continues until pressure decreases to the point that the variable heaters alone can regulate pressure. For normal transients including a full-load rejection, the pressurizer pressure control system acts promptly to prevent reaching the high pressurizer pressure reactor trip setpoint.

7.7.1.7 Pressurizer Water Level Control System

The pressurizer water inventory, or level control, provides a reservoir for the reactor coolant system inventory changes that occur due to changes in reactor coolant system density. As the reactor coolant system temperature is increased from hot zero-load to full-load values, the reactor coolant system fluid expands. The pressurizer level is programmed to absorb this change. A deadband is provided around the pressurizer level programmed setpoint to intermittently control charging and letdown. When the pressurizer water level reaches the lower limit of the deadband, it actuates the charging system. The charging system continues to operate until the level is restored to a limit above the nominal program value. When the pressurizer water level reaches the upper limit of the deadband, it actuates letdown to the liquid waste processing system.

Pressurizer water level control provides stable and accurate control of pressurizer level within a prescribed deadband around the programmed setpoint value, as derived from the plant operating parameters. Automatic level control is supplied from the point in the startup cycle where the hot zero-load level is established through 100-percent power. The reference water level is also compensated for changes in operating temperature that result from such items as rod control deadband, or reduced T_{avg} return to power operation.

7.7.1.8 Feedwater Control System

The feedwater control system consists of those controllers and associated hardware whose primary function is to regulate the flow of feedwater into the steam generator. The feedwater control system consists of two separate subsystems. The feedwater control subsystem regulates the flow of feedwater into the steam generators via the main feedwater line. The startup feedwater control subsystem regulates the flow of feedwater into the steam generators via the startup feedwater line. Flow to the startup feedwater line may be supplied by either the main or startup feedwater pump. The following two subsections provide a description of each control subsystem.

7.7.1.8.1 Feedwater Control

The feedwater control subsystem maintains a programmed water level in the shell side of the steam generator during steady-state operation, and limits the water level shrink and swell during normal plant transients. This prevents an undesirable reactor trip actuation. Indication is provided for monitoring system operation. Alarms and indications are provided to alert the plant operator of control system malfunctions or abnormal operating conditions.

Two modes of feedwater control are incorporated in the feedwater control subsystem. In the high-power control mode, the feedwater flow is regulated in response to changes in steam flow and proportional plus integral (PI)-compensated steam generator narrow range water level deviation from setpoint. In the low-power control mode, the feedwater flow is regulated in response to changes in steam generator wide-range water level and PI-compensated steam generator narrow range water level deviation from setpoint. A separate low range feedwater flow measurement is used in the low-power feedwater control mode.

The transition from the low to the high-power control mode is initiated on the basis of the filtered high range feedwater flow signal. The transition point is set at a feedwater flow corresponding to a power at which reliable steam flow indication is expected. The transition point is also low enough to allow effective feedforward control using wide range water level, and to allow feedwater flow indication within the upper limit of the low range feedwater flow measurement. If feedwater flow indication falls below the lower limit of the effective span of the low range feedwater flow measurement, integration (reset) action of the low-power mode feedwater flow controller is inhibited. Tracking is provided to allow a smooth transition between control modes and between manual and automatic control.

The feedwater valve lift required to provide the demanded feedwater flow is computed on the basis of the estimated ΔP available across the feedwater control valve, and the C_V characteristic of the valve. This compensation improves the response to changes in system ΔP, such as following the loss of one feedwater pump during high-power operation.

A high steam generator water level signal reduces the feedwater flow demand signal and closes the feedwater control valves.

7.7.1.8.2 Startup Feedwater Control

During no-load or very low power conditions, the main feedwater control subsystem is not intended to be used for automatic control of the steam generator water level. The startup feedwater control subsystem performs this function.

The startup feedwater control subsystem maintains a programmed water level in the shell side of the steam generator during low power (below approximately 10 percent of plant rated thermal power), no-load, and plant heatup and cooldown modes. During low feedwater flow demand, feedwater is controlled by the startup feedwater control subsystem. Transition between the main and startup feedwater line is automatically controlled based on flow measurements within the respective lines. The startup feedwater control subsystem is also automatically actuated on signals which indicate a loss of water inventory or heat sink in the secondary side of the steam generator and will attempt to recover the inventory loss and return the steam generator water level to the programmed value. If the startup feedwater control subsystem cannot recover the inventory deficit, reactor cooling is initiated by the passive residual heat removal system.

The startup feedwater control subsystem regulates the flow of feedwater in a manner which is similar to the way (main) feedwater is controlled in the low-power control mode. Feedwater flow is regulated in response to changes in steam generator wide-range water level and PI-compensated

steam generator narrow range water level deviation from setpoint. Tracking is provided to allow a smooth transition between control modes and between manual and automatic control.

The startup feedwater control valve lift required to provide the demanded startup feedwater flow is computed on the basis of the estimated ΔP available across the startup feedwater control valve, and the C_V characteristic of the valve. This compensation improves the response to changes in system ΔP, such as during plant heatup or cooldown where the steam pressure can change drastically.

7.7.1.9 Steam Dump Control System

The AP1000 is designed to sustain a 100-percent load rejection, or a turbine trip from 100-percent power, without generating a reactor trip, requiring atmospheric steam relief, or actuating a pressurizer or steam generator safety valve. The automatic steam dump control system, in conjunction with other control systems, is provided to accommodate this abnormal load rejection and to reduce the effects of the transient imposed on the reactor coolant system. By bypassing main steam to the condenser, an artificial load is maintained on the primary system. This artificial load makes up the difference between the reactor power and the turbine load for load rejections and turbine trips. It also removes latent and decay heat following a reactor trip.

The steam dump system is sized to pass 40 percent of nominal steam flow. This capacity, in conjunction with the performance of the reactor power control system, is sufficient to handle reactor trips from any power level, turbine trips from 50-percent power or less, and load rejections equivalent to a step load decrease of 50 percent or less of rated load. For turbine trips initiated above 50-percent power, or load rejections greater than the equivalent of a 50-percent step, the steam dump operates in conjunction with the rapid power reduction system described in subsection 7.7.1.10 to meet the performance described in the previous paragraph.

The steam dump control system has two main modes of operation:

- The T_{avg} mode uses the difference between measured auctioneered loop T_{avg} and a reference temperature derived from turbine first-stage impulse pressure, to generate a steam dump demand signal. This mode is largely used for at-power transients requiring steam dump, such as load rejections and turbine trips (where the load rejection T_{avg} mode is used) and reactor trips (where the plant trip T_{avg} mode is used). The load rejection controller is discussed in subsection 7.7.1.9.1. The plant trip controller is discussed in subsection 7.7.1.9.2.

- The pressure mode uses the difference between measured steam header pressure and a pressure setpoint to generate a steam dump demand signal. This mode is used for low-power conditions (up through turbine synchronization) and for plant cooldown. It is described in subsection 7.7.1.9.3.

Process variable input signals to the steam dump control system are fed from protection channels via isolation devices and the signal selector function. Each input (T_{avg}, turbine load, steam header pressure, and wide-range steam generator water level) is obtained from multiple transmitters of the same parameter. The signal selector rejects any signal which is bad in comparison with the remaining transmitter outputs and allows only valid measurements to be used by the control

system. This makes the steam dump system tolerant of single transmitter failures or input signal failures and eliminates interaction between the control and the protection system.

To prevent actuation of steam dump on small load perturbations, an independent load rejection sensing circuit is provided. This circuit senses the rate of decrease in the turbine load as detected by the turbine impulse chamber pressure. It unblocks the dump valves when the rate of a load rejection exceeds a preset value corresponding to a 10-percent step load decrease or a sustained ramp load decrease of greater than 5 percent per minute.

The steam dump system valves also receive a signal to close on a low wide-range steam generator water level signal. Isolating steam dump on low wide-range water level improves the plant performance to anticipated transients without reactor scram events modeled in the AP1000 Probabilistic Risk Assessment.

7.7.1.9.1 Load Rejection Steam Dump Controller

This controller prevents a large increase in reactor coolant temperature following a large, sudden load decrease. The error signal is a difference between the lead-lag compensated selected T_{avg} and the selected reference T_{avg} (designated T_{ref}), based on turbine impulse chamber pressure.

The T_{avg} input signals are the same as those used in the reactor power control system, although a signal selector algorithm in a separate controller is employed. The lead-lag compensation for the T_{avg} signal compensates for lags in the plant thermal response and in valve positioning. The lead-lag compensation in the T_{ref} signal is used to compensate for hangup effects noted in the turbine impulse pressure measurement on turbine trips and grid disconnects. It allows for a decrease in gain in the steam dump controller, thereby increasing stability. Following a sudden load decrease, T_{ref} is immediately decreased and T_{avg} tends to increase. This generates an immediate demand signal for steam dump. Following the initial steam dump opening, the reactor power control system in conjunction with the rod control system commands the control rods to insert in a controlled manner to reduce the reactor power to match turbine load. On a load rejection resulting in a turbine runback, the steam dump terminates when the reactor power matches the turbine load and the temperature error is within the maneuvering capability of the control rods. On a turbine trip or grid disconnect, the steam dump modulates closed in response to the control rods reducing nuclear power to approximately 15-percent load. At this point, rod insertion stops and the plant stabilizes in preparation for a turbine/generator restart and/or grid synchronization with the steam dumps partially open.

7.7.1.9.2 Plant Trip Steam Dump Controller

Following a reactor trip, the load rejection steam dump controller is defeated and the plant trip steam dump controller becomes active. Since control rods are not available in this situation, the demand signal for steam dump is the error signal between the lead-lag compensated auctioneered T_{avg} and the no-load reference T_{avg}. When the error signal exceeds a predetermined setpoint, the steam dump valves are opened in a prescribed sequence. As the error signal reduces in magnitude, indicating that the reactor coolant system T_{avg} is being reduced toward the reference no-load value, the dump valves are modulated by the plant trip controller. This regulates the rate of removal of decay heat and establishes the equilibrium hot shutdown condition.

7.7.1.9.3 Steam Header Pressure Controller

Decay heat removal between hot standby and residual heat removal system cut-in conditions is maintained by the steam header pressure controller. This controller uses the difference between steam header pressure and a pressure setpoint to control the steam flow to the condensers. Reset action is used to eliminate steady-state error. This controller uses the same steam dump valves as the load rejection and plant trip controllers described in subsections 7.7.1.9.1 and 7.7.1.9.2. The steam header pressure control mode is manually selected by the operator. The pressure setpoint is manually adjusted by the operator based on the desired reactor coolant system temperature. In addition, the controller has a feature that allows automatically controlled plant cooldowns at a chosen rate (within limits). The operator can enter the desired cooldown rate and the desired target reactor coolant system temperature. The control system then dumps the required steam to achieve the setpoint cooldown rate and stops at the target setpoint.

7.7.1.10 Rapid Power Reduction System

The rapid power reduction system rapidly reduces the nuclear power to a level capable of being handled by the steam dump system for a large load rejection (greater than 50-percent power reduction at a rapid rate). Upon the detection of a large and rapid turbine power reduction (via a rate/lag circuit, similar to that used for steam dump control), the circuit provides a signal demanding the release of a preselected number of control rods. The dropping of these preselected rods causes the reactor power to rapidly reduce to approximately 50-percent power.

The large load rejection also actuates the steam dump system and the reactor power control system via a primary-to-secondary power mismatch signal. Following the initiation of the load rejection, the power control rods insert in a controlled manner due to the mismatch between the programmed reference average coolant temperature (based on turbine impulse chamber pressure) and the compensated average coolant temperature measured in the reactor coolant loops. In a similar manner, the load rejection steam dump controller controls the steam dump valves to prevent a large increase in reactor coolant temperature. Following the release of the preselected control rods, the power control system continues to insert the remaining control group control rods to reduce power (by temperature control channel trying to match T_{avg} to T_{ref}). Following the initial opening, the steam dump valves modulate closed based upon the (T_{avg} - T_{ref}) signal.

Controlled rod insertion and steam dump modulation continue until power is reduced to approximately 15-percent power. At this time, the rod motion ceases and the plant stabilizes with steam dump maintained to match the steam flow to the thermal load. The operators can then switch to pressure mode of control on the steam dump control system, recover the released control rods, and establish normal rod control. A normal power escalation is then performed through the following actions: resynchronize the turbine/generator, if necessary, perform turbine loading until the steam dumps close, reset the steam dump controller, place the plant back into automatic, and return to the desired power level.

7.7.1.10.1 Rod Block Interlock

To avoid the potential for a withdrawal of the normally functioning power control rods following the rod release by the rapid power reduction system, a rod withdrawal block is actuated. Actuation

occurs by the reduction of reactor power (P-17) after the initiation of the rapid power reduction system as discussed in subsection 7.2.1.1.11. The rod withdrawal block does not adversely impact the performance of the rapid power reduction system. The demand of the power control subsystem is a continuous rod insertion. Rod withdrawal during the power reduction phase is not required.

7.7.1.10.2 Rapid Power Reduction Rod Selection

The number of rods needed to obtain this power reduction is dependent on the core burnup during the fuel cycle. In addition, if a large load rejection (grid disconnect) is initiated at a part-power condition (50-percent to 100-percent power), then a reduced number of control rods need to be released. Therefore, a means is provided to have the control system select which rods will be released by the rapid power reduction system.

The selection of the rods that are released during the rapid power reduction is based on a thermal power measurement. The thermal power is integrated over time to arrive at a core burnup. Depending on the core burnup and the plant power level, the choice of the control rods to be released by the rapid power reduction system is determined. Capability is provided for the operator to correct the integrated burnup periodically based upon a more detailed burnup calculation.

7.7.1.11 Diverse Actuation System

The diverse actuation system is a nonsafety-related system that provides a diverse backup to the protection system. This backup is included to support the aggressive AP1000 risk goals by reducing the probability of a severe accident which potentially results from the unlikely coincidence of postulated transients and postulated common mode failure in the protection and control systems.

The protection and safety monitoring system is designed to prevent common mode failures. However, in the low probability case where a common mode failure does occur, the diverse actuation system provides diverse protection. The specific functions performed by the diverse actuation system are selected based on the PRA evaluation. The diverse actuation system functional requirements are based on an assessment of the protection system instrumentation common mode failure probabilities combined with the event probability.

The functional logic for the diverse actuation system is shown in Figure 7.2-1, sheets 19 and 20.

Automatic Actuation Function

The automatic actuation signals provided by the diverse actuation system are generated in a functionally diverse manner from the protection system actuation signals. The common-mode failure of sensors of a similar design is also considered in the selection of these functions.

The automatic actuation function is accomplished by redundant microprocessor-based subsystems. Input signals are received from the sensors by an input signal conditioning block, which consists of one or more electronic modules. This block converts the signals to standardized levels, provides a barrier against electromagnetic and radio frequency interference, and presents the resulting

signal to the input signal conversion block. The conversion block continuously performs analog to digital signal conversions and stores the value for use by the signal processing block.

The signal processing block polls the various inputs under the control of a software-based algorithm, evaluates the input signals against stored setpoints, executes the programmed logic when thresholds are exceeded, and issues actuation commands.

The resulting output signals are passed to the output signal conversion block, whose function is to convert microprocessor logic states to parallel, low-level dc signals. These signals are passed to the output signal conditioning block. This block provides high-level signals capable of switching the traditional power plant loads, such as breakers and motor controls. It also provides a barrier against electromagnetic and radio frequency interference.

Diversity is achieved by the use of a different architecture, different hardware implementations and different software from that of the protection and safety monitoring system.

The diverse design uses standard input modules designed for use with small industrial computer systems. It also uses a microprocessor board different from those used in the protection system.

Software diversity is achieved by running different operating systems and programming in different languages.

The diverse automatic actuations are:

- Trip rods via the motor generator set, trip turbine, initiate the passive residual heat removal, actuate core makeup tanks, and trip the reactor coolant pumps on low wide-range steam generator water level

- Open the passive heat removal discharge isolation valves and close the in-containment refueling water storage tank gutter isolation valves on high hot leg temperature

- Trip rods via the motor generator set, trip turbine, actuate the core makeup tanks, and trip the reactor coolant pumps on low pressurizer water level

- Isolate selected containment penetrations and start passive containment cooling water flow on high containment temperature

The selection of setpoints and time responses determine that the automatic functions do not actuate unless the protection and safety monitoring system has failed to actuate to control plant conditions. Capability is provided for testing and calibrating the channels of the diverse actuation system.

Manual Actuation Function

[*The manual actuation function of the diverse actuation system is implemented by hard-wiring the controls located in the main control room directly to the final loads in a way that completely bypasses the normal path through the control room multiplexers, the protection and safety monitoring system cabinets, and the diverse actuation system automatic logic.*]*

The diverse manual functions are:

- Reactor and turbine trip
- Passive containment cooling actuation
- Core makeup tank actuation and reactor coolant pump trip
- Open stage 1 automatic depressurization system valves
- Open stage 2 automatic depressurization system valves
- Open stage 3 automatic depressurization system valves
- Open stage 4 automatic depressurization system valves
- Open the passive residual heat removal discharge isolation valves and close the in-containment refueling water storage tank gutter isolation valves
- Selected containment penetration isolation
- Containment hydrogen igniter actuation
- Initiate in-containment refueling water storage tank injection
- Initiate containment recirculation
- Initiate in-containment refueling water storage tank drain to containment

Actuation Logic Function

There are two actuation logic modes, automatic and manual. The automatic actuation logic mode functions to logically combine the automatic signals from the two redundant automatic subsystems in a two-out-of-two basis. The combined signal operates a power switch with an output drive capability that is compatible, in voltage and current capacity, with the requirements of the final actuation devices. The two-out-of-two logic is implemented by connecting the outputs in series. The manual actuation mode operates in parallel to independently actuate the final devices.

*NRC Staff approval is required prior to implementing a change in this information; see DCD Introduction Section 3.5.

Actuation signals are output to the loads in the form of normally de-energized, energize-to-actuate signals. The normally de-energized output state, along with the dual, two out of two redundancy reduces the probability of inadvertent actuation.

The diverse actuation system is designed so that, once actuated, each mitigation action goes to completion. Any subsequent return to operation requires deliberate operator action.

Indication

To support the diverse manual actuations, sensor outputs are displayed in the main control room in a manner that is diverse from the protection system display functions. The indications that are provided from at least two sensors per function are:

- Steam generator water level – for reactor trip and passive residual heat removal actuations, and for overfill prevention by manual actuation of the automatic depressurization system valves

- Hot leg temperature – for passive residual heat removal actuation

- Core exit temperature – for automatic depressurization system actuation and subsequent initiation of in-containment refueling water storage tank injection and also containment hydrogen igniter actuation

- Pressurizer level – for core makeup tank actuation and reactor coolant pump trip

- Containment temperature – for containment isolation and passive containment cooling system actuation

Isolation

The diverse actuation system uses sensors that are separate from those being used by the protection and safety monitoring system and the plant control system. This prohibits failures from propagating to the other plant systems through the use of shared sensors.

There is signal isolation between the two subsystems within the diverse actuation system, one for each input and output path. These isolators are characterized by a high common mode voltage withstand capability to provide the necessary isolation against faults. The configuration is set up such that the isolation devices are capable of protecting against fault propagation between the diverse actuation system subsystems.

Actuation interfaces are shared between the diverse actuation system and the protection and safety monitoring system. The diverse actuation system actuation devices are isolated from the protection and safety monitoring system actuation devices, so as to avoid adverse interactions between the two systems. The actuation devices of each system are capable of independent operation that is not affected by the operation of the other. The diverse actuation system is designed to actuate components only in a manner that initiates the safety function. This type of interface also prevents the failure of an actuation device in one system from propagating a failure into the other system.

The diverse actuation system and the protection and safety monitoring system use independent and separate uninterruptible power supplies.

Operability, Availability, and Testing

The diverse actuation system is designed to provide protection under all plant operating conditions in which the reactor vessel head is in place and non-Class 1E UPS power is available. The automatic actuation processors, in each of the two redundant automatic subsystems of the diverse actuation system, are provided with the capability for channel calibration and testing while the plant is operating. To prevent inadvertent DAS actuations during online calibration, testing activities or maintenance, the normal activation function is bypassed. Testing of the diverse actuation system is performed on a periodic basis.

Equipment Qualification and Quality Standards

The diverse actuation system is located in a controlled environment, but is capable of functioning during and after normal and abnormal events and conditions that include:

- Wide temperature range of 40° to 120°F
- Noncondensing relative humidity up to 95 percent
- Radio frequency and electromagnetic interference

The diverse actuation system processor cabinets are located in the portion of the Annex Building that is a Seismic Category II structure. The diverse actuation system equipment, including actuated devices, is designed and tested in accordance with industry standards. The adequacy of the hardware and software is demonstrated through the verification and validation program discussed in subsection 7.1.2.14. This program provides for the use of commercial off-the-shelf hardware and software. As the diverse actuation system performs many of the protection functions associated within the ATWS systems used in existing plants, the diverse actuation system is designed to meet the quality guidelines established by Generic Letter 85-06, "Quality Assurance Guidelines for ATWS Equipment that is not Safety-Related."

7.7.1.12 Signal Selector Algorithm

The plant control system for the AP1000 derives some of its control inputs from signals that are also used in the protection and safety monitoring system. The advantages of this design are:

- The nonsafety-related plant systems are controlled from the same measurements which provide protection. This permits the control system to function in a manner which maintains margin between operating conditions and safety limits, and reduces the likelihood of spurious trips.

- Reducing the number of redundant measurements for any single process variable reduces the overall plant complexity at critical pressure boundary penetrations. This leads to a reduction in separation requirements within the containment, as well as to a decrease in plant cost and maintenance requirements.

To obtain these advantages, measures are taken to provide the independence of the protection and control systems. The criteria for these measures are contained in IEEE 603-1991, Section 5.6.3. Isolation devices are provided to guard the protection system against possible electrical faults in the control system.

To avoid a single component failure or spurious signal causing an inadvertent plant trip while a channel is in test or maintenance, the protection and safety monitoring system uses the bypass logic discussed in subsection 7.1.2.9. This necessitates a different mechanism for achieving the functional independence of control and protection.

Functional independence of control and protection is obtained by signal selector algorithms. The purpose of the signal selector algorithm is to prevent a failed signal, caused by the failure of a protection channel, from initiating a control action that could lead to a plant condition requiring that protective action. The signal selector function provides this capability by comparing the redundant signals and automatically eliminating an aberrant signal from use in the control system. This capability exists for bypassed sensors or for sensors whose signals have diverged from the expected error tolerance.

The operation of the signal selector algorithm is described in subsection 7.1.3.2.

7.7.2 Analysis

The control system is capable of maneuvering the plant through certain reference transients. This maneuvering is done without the need for manual intervention and without violating plant protection or component limits. The plant control systems provide high reliability during these anticipated operational occurrences and meet the following objectives:

- The capability to accept 10-percent step load decreases from an initial power level between 100-percent and 25-percent of full power, and step load increase of 10-percent from an initial power level between 15-percent and 90-percent of full power without reactor trip or steam dump actuation.

- The capability to accept ramp load changes at 5-percent power per minute while operating in the range of 15-percent to 100-percent of full power without reactor trip or steam dump system actuation, subject to core power distribution limits.

- The capability to accept the design full-load rejection without reactor trip.

- The capability to accept a turbine trip from full-power operation without reactor trip. This capability is provided with the normally available systems (such as steam dump and feedwater control).

- The capability to follow the design basis network load follow pattern for 90-percent of the fuel cycle. The design basis load follow pattern is defined as the daily (24-hour period) cycle consisting of 10 to 18 hours of operation at 100-percent power, followed by a 2-hour linear ramp to 50-percent power, followed by 2 to 10 hours of operation at 50-percent power and then a 2-hour linear ramp back to 100-percent power.

- The capability to satisfy a 20-percent power increase or decrease within 10 minutes.

- The capability of handling grid frequency changes equivalent to 10-percent peak-to-peak power changes at a two percent per minute rate. This capability is provided over a 15- to 100-percent power range throughout the plant operating life. A total of 35 peak-to-peak swings per day are allowed.

The control system permits maneuvering the plant through the transients without actuation of the following:

- Steam generator safety valves
- Steam generator power operated relief valves
- Pressurizer safety valves

In addition, these valves are not actuated during a normal plant trip.

7.7.3 Combined License Information

This section has no requirement for information to be provided in support of the Combined License application.

Table 7.7-1

ROD CONTROL SYSTEM INTERLOCKS - POWER CONTROL SUBSYSTEM

Designation	Derivation	Function
C-1	2/4 neutron flux (intermediate range) above setpoint	Blocks automatic and manual control rod withdrawal
C-2	2/4 neutron flux (power range) above setpoint	Blocks automatic and manual control rod withdrawal
C-3	Margin to overtemperature ΔT (output of signal selector) below setpoint	Blocks automatic and manual control rod withdrawal
		Actuates turbine runback via load reference
C-4	Margin to overpower ΔT (output of signal selector) below setpoint	Blocks automatic and manual control rod withdrawal
		Actuates turbine runback via load reference
C-5	Turbine impulse chamber pressure (output of signal selector) below setpoint (blocked if in low-power rod control mode)	Blocks automatic control rod withdrawal
		Defeats remote load dispatching (if remote load dispatching is used)
C-11	1/1M bank control rod position above setpoint	Blocks automatic rod withdrawal
C-16	Reactor coolant system T_{avg} or (T_{avg} minus T_{ref}) signal (output of signal selector) below setpoint	Stops automatic turbine loading until condition clears
P-17	2/4 negative flux rate below setpoint	Blocks automatic rod withdrawal

Table 7.7-2

ROD CONTROL SYSTEM INTERLOCKS - AXIAL OFFSET CONTROL SUBSYSTEM

Designation	Derivation	Function
C-1	2/4 neutron flux (intermediate range) above setpoint	Blocks automatic and manual axial offset control rod withdrawal
C-2	2/4 neutron flux (power range) above setpoint	Blocks automatic and manual axial offset control rod withdrawal
C-5	Turbine impulse chamber pressure (output of signal selector) below setpoint	Blocks automatic axial offset control rod withdrawal and insertion
C-15	1/1 bank AO control rod position below setpoint	Blocks automatic axial offset control rod insertion
C-17	1/1M bank control rod position below setpoint	Blocks automatic axial offset control rod withdrawal
C-18	1/1M bank control rod position above setpoint	Blocks automatic axial offset control rod insertion
---	Power control rods moving in	Blocks automatic axial offset control rod insertion and withdrawal
---	Power control rods moving out	Blocks automatic axial offset control rod insertion and withdrawal
---	Power control rods in manual	Blocks automatic axial offset control rod insertion and withdrawal
P-17	2/4 negative flux rate below setpoint	Blocks automatic axial offset control rod withdrawal

Table 7.7-3 (Sheet 1 of 3)

CROSS REFERENCE TABLE FOR DEFENSE-IN-DEPTH FUNCTIONS SUPPORTED BY THE PLANT CONTROL SYSTEM

Supported System	Defense-in-Depth Function	DCD Section	DCD Figure
Component Cooling Water (CCS)	Provides cooling for normal residual heat removal system heat exchangers and pumps when the reactor coolant system pressure and temperature are below 450 psig and 350°F.	9.2.2.1.2.2 9.2.2.4.3	9.2.2-2
Component Cooling Water (CCS)	Provides cooling for the miniflow heat exchangers of the chemical and volume control system makeup pumps.	9.3.6.3.1	9.2.2-2
Component Cooling Water (CCS)	Provides cooling for the spent fuel pool heat exchangers for heat removal from the spent fuel pool.	9.2.2.1.2.3	9.2.2-2
Chemical and Volume Control (CVS)	Supply makeup and boration to the reactor coolant system.	9.3.6.7	9.3.6-1
Chemical and Volume Control (CVS)	Supply coolant to the pressurizer auxiliary spray line.	9.3.6.4.5	9.3.6-1
Standby Diesel and Auxiliary Boiler Fuel Oil (DOS)	Supply fuel to the onsite standby power diesel generators.	9.5.4	9.5.4-1
Main and Startup Feedwater (FWS)	Provide startup feedwater for heat removal from the reactor coolant system (startup feedwater).	10.4.9.1.2	10.4.7-1 10.3.2-1
Normal Residual Heat Removal (RNS)	Remove heat from the reactor coolant system during shutdown operation at reduced pressure and temperature.	5.4.7.1.2.1	5.4-7
Normal Residual Heat Removal (RNS)	Provide low temperature overpressure protection for the reactor coolant system.	5.4.7.1.2.5	5.4-7
Normal Residual Heat Removal (RNS)	Provide low-pressure makeup to the reactor coolant system and remove heat from the reactor coolant system following actuation of the automatic depressurization system.	5.4.7.1.2.4 5.4.7.4.4	5.4-7

Table 7.7-3 (Sheet 2 of 3)

CROSS REFERENCE TABLE FOR DEFENSE-IN-DEPTH FUNCTIONS SUPPORTED BY THE PLANT CONTROL SYSTEM

Supported System	Defense-in-Depth Function	DCD Section	DCD Figure
Spent Fuel Pool Cooling (SFS)	Provide for heat removal from the spent fuel stored in the spent fuel pool by pumping the water from the pool through a heat exchanger, and then returning the water to the pool.	9.1.3.2	9.1-8
Steam Generator (SGS)	Provide decay heat removal capability during shutdown operations by delivery of startup feedwater flow to the steam generator and venting of steam from the steam generators to the atmosphere via the power-operated relief valves.	10.4.9 10.3	10.4.7-1 10.3.2-1
Service Water (SWS)	Provide the capability for removing heat from the component cooling water system.	9.2.1.1.2	9.2.1-1
Service Water (SWS)	Provide the capability for removing heat from the spent fuel pool via the spent fuel cooling and component cooling water systems.	9.2.2 and Table 9.2.2-2	9.2.2-1 9.2.2-2
Service Water (SWS)	Provide the capability for decay heat removal at shutdown conditions through the normal residual heat removal and component cooling systems.	9.2.2 and Table 9.2.2-2	9.2.2-1 9.2.2-2
Nuclear Island Nonradioactive Ventilation (VBS)	Provide ventilation and cooling to the main control room envelope, Class 1E instrumentation and control rooms, Class 1E dc equipment rooms, and Class 1E battery rooms.	9.4.1	9.4.1-1 all sheets
Containment Hydrogen Control (VLS)	Provide hydrogen igniters to control hydrogen concentration in excess of the recombiner capability.	6.2.4	N/A
Central Chilled Water (VWS)	Provide chilled water to support the nuclear island nonradioactive ventilation system cooling of the main control room envelope, Class 1E instrumentation and control rooms, Class 1E dc equipment rooms, and the Class 1E battery rooms.	9.2.7	9.2.7-1 sheets 6 & 7
Central Chilled Water (VWS)	Provide chilled water to support the cooling functions of the compartment unit coolers for the normal residual heat removal system pump.	9.2.7	9.2.7-1 sheets 6 & 7

Table 7.7-3 (Sheet 3 of 3)

CROSS REFERENCE TABLE FOR DEFENSE-IN-DEPTH FUNCTIONS SUPPORTED BY THE PLANT CONTROL SYSTEM

Supported System	Defense-in-Depth Function	DCD Section	DCD Figure
Central Chilled Water (VWS)	Provide chilled water to support the cooling functions of the compartment unit coolers for the chemical and volume control system makeup pump.	9.2.7	9.2.7-1 sheets 6 & 7
Annex/Auxiliary Building Nonradioactive Heating and Ventilation (VXS)	Provide ventilation of the electrical switchgear rooms that contain the diesel bus switchgear. Provide ventilation of the equipment room that contains the switchgear room air-handling units.	9.4.2	9.4.2-1 sheets 3, 4, 5, and 6
Diesel Generator Building Heating and Ventilation (VZS)	Provide ventilation and cooling of the diesel generator building, and ventilation and heating of the diesel oil transfer module enclosure to support operation of the onsite standby power system.	9.4.10	9.4.10-1
Onsite Standby Power (ZOS)	Supply ac power to the Class 1E dc and UPS system.	8.3 and Table 8.3.1-2	8.3.1-2
Onsite Standby Power (ZOS)	Supply ac power to selected electrical components of the plant defense-in-depth, nonsafety-related systems.	8.3 and Table 8.3.1-2	8.3.1-2